RAI 4.6.3-1

Section 4.6.3 of the LRA states that, "In addition, the steady-state temperature without cooling water and continuous RHR flow at 380 °F results in the temperature of the surrounding concrete of approximately 210 °F." Define the steady-state temperature. Is the temperature in the hot pipe containment penetration at 380°F considered as a normal operating condition? Is the temperature in the concrete that surrounds the hot pipe penetration at approximately 210°F considered as a normal operating condition? If answers to these questions are positive, please justify your results since ACI 349 Code limitation of 200°F has been exceeded. Describe how the 210°F was obtained(e.g., measured or calculated).

RNP Response:

Steady state temperature occurs when the concrete cylinder wall temperature reaches its highest value and the heat is either stored in the wall or lost to the atmosphere off of the wall.

The maximum operating temperature of the RHR pipe at the penetration during heatup and cooldown transients is 380°F. This is not the normal operating condition for the pipe. The RHR system operates at above 200°F for approximately 1.6% of the time. This is a conservative estimate based on plant experience of operating the RHR system at 40 hours per heatup/cooldown cycle, assuming 3.5 cycles per year.

Therefore, the 210°F concrete temperature is not considered to be the normal operating condition. Rather, it is based on the above-described estimate for RHR system operating time above 200°F (approximately 1.6% of the time). ACI 349, Appendix A – Thermal Considerations, Section A.4, states: "temperatures shall not exceed 350°F...for accident or any other short term period." This 40 hours per heatup/cooldown cycle was considered a short term period or transient condition. This temperature was calculated to be 208.5°F and rounded to 210°F.

RAI 4.6.3-2

The LRA states that, "The analysis of concrete temperature determined that the allowable number of cycles of heatup and cooldown, at 40 hours or less per cycle, was 252 cycles." What are the heatup and cooldown temperatures used in the analysis? Was there a thermal fatigue analysis for concrete? Based on the analysis, after 252 cycles, describe the expected condition of concrete, such as disintegration or loss of strength. Describe the analysis concept and procedures, and submit the analysis results at the end of 252 cycles.

RNP Response:

The concrete heatup and cooldown temperatures are from 200°F to 210°F during reactor coolant system heatup and 210°F to 200°F during reactor coolant system cooldown.

A thermal fatigue analysis was not performed.

An evaluation was developed that justified operation with cooling water isolated to the RHR penetrations for a continuous period of approximately 18 months. Cooling water was actually isolated to the RHR penetration for less than 4 months between Refueling Outage-15 and -16, leaving the equivalent of 14 months (or 10,080 hours) of "unused" operation with cooling water isolated. The available time of 10,800 hours is equivalent to 252 cycles of heatup/cooldown based on 40 hours per cycle. The 252 cycles of heatup/cooldown bound the projected number of heatup/cooldown cycles (120) and the design heatup/cooldown cycles (200) shown in LRA Section A.2.1.1.
The RHR penetrations are only subject to high temperatures during RHR operation, because the RHR system only operates during the heatup and cooldown cycles, not during normal plant operation.

No disintegration or physical degradation of the concrete was predicted under the above described operating conditions. The subject evaluation determined a 25% reduction in compressive strength (3010 psi) due to temperature affects was greater than the concrete design strength (3000 psi) used in original concrete calculations at the penetration. The reduced concrete strength (3010 psi) at the penetration was determined to be acceptable. This determination was conservative because the actual concrete compressive strengths from field testing were higher than that used in the evaluation, and the actual temperatures are less than the 277°F used in the evaluation.

RAI 4.6.3-3

The LRA states, ". . . the projected number of cycles for 60-year of operation (120 cycles) is less than the allowed number of cycles for penetration S-15 (252 cycles), ..." Please justify the 120 cycles in 60-year of operation, accounting for shutdowns due to maintenance or other reasons.

RNP Response:

A review of RNP operational history to-date and projected cycles were performed based on 27 years of plant operation. The actual cycle count was 87 heatups and 86 cooldowns. The projection for 60 years was performed by summing the actual transient count through 1990 to the rate of accumulation developed in the 1990 through 1999 period which was then multiplied by 40 years, i.e., 120 cycles (120 heatups and 120 cooldowns). The number of design cycles for plant heatups is 200, and for plant cooldowns is 200, as stated in LRA Appendix A, Section A.2, Table 3.9.1-1. Both the projected heatup/cooldown cycles (120) and the design cycles (200) are less than the number of cycles allowed for penetration S-15 (252). This includes expected shutdowns due to maintenance and other reasons.

RAI 4.6.4-1

The applicant stated in its application that prior to the extended period of operation, either an analysis will be performed to permit eliminate credit for the Boraflex panels in the spent fuel racks in determining K_{eff} for the spent fuel array or credit will be used and the current Boraflex Monitoring Program will be evaluated against the 10 elements for an acceptable license renewal aging management program documented in the GALL report.

a. Provide the basis for the decision and the decision to either eliminate credit for the Boraflex or continue with the Boraflex Monitoring Program.

RNP Response:

RNP currently intends to request a Technical Specifications change to eliminate credit for Boraflex. This request should be submitted for NRC review during 2003. The associated analysis is in progress and is based on an approved methodology. The proposed Technical Specifications change is expected to be consistent with similar changes that have been approved for other licensees, and represents a reasonable approach for resolution of Boraflex degradation.

RAI 4.6.4-2

Measurement of boron areal density (BADGER) in conjunction with a predictive code (RACKLIFE) has been shown to be a conservative method of determining the amount of Boraflex degradation. The staff believes that the use of BADGER testing in combination with a predictive code, i.e., RACKLIFE, provides the best method for determining the Boraflex degradation. Sampling and analysis of silica concentration can help determine the average Boraflex loss but would not identify the most degraded panel.

a. How often is the silica concentration measured?

b. Provide the degradation rate of the Boraflex panels.

RNP Response:

Please refer to the RNP Response to RAI 4.6.4-1. The revised analysis is expected to credit soluble boron and fuel assembly burnup in the reactivity analysis, and is based on an approved methodology. Upon NRC approval of the proposed Technical Specifications change, the license renewal intended function provided by Boraflex panels will no longer be applicable, and the current Boraflex monitoring procedure will be terminated.

RAI 4.6.4-3

In its response to NRC Generic Letter 96-04, the applicant stated that using the long term coupon program, monitoring the silica concentration in the spent fuel pool and comparison of silica concentration with industry data provides assurance that a 5% subcriticality margin can be maintained. Since Boraflex degrades at different rates for different locations in the same pool, it would not be appropriate to compare the silica concentration in different spent fuel pools to conclude the degree of degradation in one spent fuel pool is less than in another pool. Inspection of Boraflex coupons can provide information of the rate at which the Boraflex panels are degrading; however, these coupons are smaller in size and are affected by their location in the spent fuel pool.

a. Provide the basis used by the applicant to determine that a 5% sub-criticality margin is maintained by examining the removed coupons.

b. Provide the types of tests performed on the coupons that are removed.

c. Provide the location of the coupons with respect to the fuel assemblies (top, bottom, middle).

RNP Response:

Please refer to the RNP Responses to RAIs 4.6.4-1 and 4.6.4-2.

RAI 4.6.4-4

The applicant's FSAR Supplement summary description for the "Aging of Boraflex in the Spent Fuel Pool" time-limited aging analysis (TLAA) should be revised to reflect the information in the applicant's responses to RAIs 4.6.4-1, 4.6.4-2, and 4.6.4-3. Include an updated FSAR Supplement summary description for the "Aging of Boraflex in the Spent Fuel Pool" TLAA to reflect the information both in Section A.3.2.8 of Appendix A to the license renewal application and CP&L's responses to RAIs 4.6.4-1, 4.6.4-2, and 4.6.4-3, when CP&L's responses to the RAIs are formally submitted under oath and affirmation to the NRC document control desk.

RNP Response:

Subsection A.3.2.8, Aging of Boraflex in Spent Fuel Pool, will be modified to reflect the RNP Responses to RAIs 4.6.4-1 and 4.6.4-2.

RAI B.1-1

10 CFR 54.21(d) requires that each license renewal application (LRA) contain a FSAR supplement; and that the supplement contain a summary description of the programs and activities for managing the effects of aging for the period of extended operation.

Appendix "B" of the LRA discusses aging management programs (AMPS) and evaluates them against a defined program from the GALL Report (NUREG 1801), and a conclusion is reached regarding consistency with NUREG 1801.The LRA Appendix "A", FSAR supplement, contains a brief summary description of the programs for managing aging effects; however, it does not indicate programs are consistent with NUREG-1801. Clarify in the FSAR supplement which AMPs are consistent with NUREG-1801.

RNP Response:

To document consistency of RNP AMPs with NUREG-1801 defined programs, a statement will be incorporated into the LRA UFSAR Supplement, Appendix A, as follows:

> "This program is consistent with the corresponding program described in the GALL Report"

Those AMPs that take exception to one or more provisions of the corresponding NUREG-1801 defined program, or do not have a corresponding program in NUREG-1801, will not incorporate this statement. As noted in the existing descriptions of AMPs in Appendix A of the LRA, enhancements to the programs are required to ensure consistency with the GALL-defined program. These enhancements will be accomplished prior to the period of extended operation. As the enhancements to the programs are completed, the AMP descriptions will be modified to replace the commitment to enhance the program with the above statement of consistency.

Consistency of an RNP AMP with the corresponding GALL-defined program can be ascertained by the statements in the "Conclusion" section of each AMP description provided within the LRA, Appendix B.

RAI B.2.1-1

The inservice examination for steam generator shell welds governed by ASME Section XI Table IWC-2500-1, Examination Category C-A, requires volumetric examination of circumferential welds. The discussion section of Item 2 in LRA Table 3.1-1 focuses on the issue raised in IN 90-04 and addressed in Item D1.1-c of the GALL Table IV.D1 that during ultrasonic examination of these welds, signal from flaws in the weld are likely to be masked by the corner-trap signal from the geometric irregularity in the steam generator upper shell-to-transition cone girth weld.

A. Please discuss if any other nondestructive examination is to be performed to reliably detect aging effects addressed in the Table 3.1-1.

B. If no additional nondestructive examination activities are proposed to detect the aging effects, justify how your current ultrasonic technique is capable of detecting flaws initiating at the location of geometric irregularity.

RNP Response:

LRA Table 3.1-1, Item 2, addresses GALL Report Section IV.D1.1-c, including a concern originally identified in IN 82-37, and later in INs 85-65 and 90-04. The subject of these INs is cracking of the upper shell-to-transition cone girth welds in steam generators. RNP has implemented measures for addressing this concern as discussed in LRA Table 3.1-2, Item 2, and as follows.

Non-reportable indications in the transition cone to upper shell girth weld on the "B" steam generator were identified by conventional UT during a regularly scheduled inservice inspection conducted in 1990 during RO-13. As a result, similar welds on the "A" and "C" steam generators were inspected, and several short (2" or less), shallow (0.47" on C, 0.293" on A), circumferentially oriented flaws were identified. CP&L then elected to perform internal fluorescent magnetic particle examination of a portion of the weld on the "A" steam generator, as a check on both UT sizing and the nature of the indications. This examination confirmed that the indications were in fact short, and suggested that they were fabrication-related, since the indications had the appearance of weld porosity in some locations, and all indications were confined to the weld metal in the girth weld. The location of the indications was re-welded in 1984 as part of the steam generator replacement program.

An evaluation was then performed to determine the efficacy of continued safe operation with these indications. The evaluation concluded that safe operation could continue provided the welds were re-inspected in accordance with ASME Section XI requirements. Details of this process are provided in the RNP letter from S. D. Floyd (CP&L) to NRC, Serial NLS-91-021: "Steam Generator

Inspection – Follow-Up Information," dated May 7, 1991. Subsequent inspections confirmed that no cracking existed in the girth weld region that could impact the continued safe operation of the unit.

The ASME Section XI program has incorporated provisions for augmented inspection of the upper shell-to-transition cone girth welds (see Appendix E of the attachment to the RNP letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0100: "Inservice Inspection Program for the Fourth Ten-Year Interval," dated August 17, 2001). These augmented inspections are in addition to normal Section XI periodic requirements, and will ensure the reliable detection of aging effects addressed in LRA Table 3.1-1.

As stated above, augmented inspections of the upper shell-to-transition cone girth welds, in addition to the normal Section XI periodic testing, will be performed.

RAI B.2.2-1

The applicant stated in its application that its Water Chemistry Program implements a later revision of the EPRI guidelines for Primary and Secondary Water Chemistry than that specified in GALL. Please discuss whether any differences exist between the applicant's water chemistry program and the referenced program.

RNP Response:

Page B-12 of the LRA states:

> *"The Water Chemistry Program differs from GALL Section XI.M2, Water Chemistry, with respect to:*
>
> - *An aging mechanism identified in the RNP AMR was not identified in the GALL Report (Loss of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces).*
> - *The RNP Water Chemistry Program implements later revisions of the EPRI guidelines for Primary and Secondary Water Chemistry than recommended in the GALL Report. The RNP Water Chemistry Program is based on the current, approved revisions of EPRI Guidelines as prescribed by NEI 97-06."*

Since the LRA Water Chemistry Program did not use exactly the same revisions of the EPRI guidelines, RNP conservatively determined that this was an exception.

It is further stated on page B-12 of the LRA:

> *"These differences have no adverse effects on the ability of the program to manage aging effects, and they are not considered to be actual exceptions to the elements of the Water Chemistry Program described in the GALL Report."*

Further, on page B-14 of the LRA (under the discussion of the Steam Generator Tube Integrity Program) it states:

"NRC Generic Letter (GL) 97-05, "Steam Generator Tube Inspection Guidelines," required PWR licensees to verify that licensee steam generator tube inspection practices were consistent with existing regulatory requirements and plant licensing bases. In response to the GL, RNP committed to implement the guidance of NEI 97-06, "Steam Generator Program Guidelines," with exceptions, as described in the RNP correspondence. By letter dated August 13, 1998, the

NRC did not find any concerns relative to compliance with the RNP licensing basis for the steam generator tube inspection techniques in response to GL 97-05."

The RNP Steam Generator Program implements these guidelines (which include water chemistry) and allows local deviations to industry guidelines or industry recommendations whether they are in the inspection, repair, or chemistry arenas. Such deviations are allowed by paragraph 1.1 of EPRI TR-107569-V1 by using a documented technical justification for each deviation or through application of performance based criteria and risk based methodologies. Since the use of technically justified deviations is allowed by the industry guidelines, they are not considered inconsistent. The RNP Steam Generator Program also addresses RNP's commitment to NEI 97-06.

Page B-12 of the LRA concludes:

> *"Based on the above, the Water Chemistry Program is consistent with GALL Section XI.M2, Water Chemistry, and implementation of the Program provides reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation."*

RAI B.2.2-2

The applicant stated in its application that its Water Chemistry Program has been subject to periodic internal and external activities. Please explain what kind of activities were performed and the results of the activities.

RNP Response:

The Water Chemistry Program is subject to periodic self-assessments (internal) as well as assessments by the Nuclear Assessment Section (external). Performance–based assessments involve a review of the program for efficacy. Typically, this consists of a combination of document review, interviews, field observations, etc. Subject matter experts (both internal and external to Progress Energy) are also used to aid in these assessments.

The results of these assessments are captured as part of the Corrective Action Program and condition reports are generated to track suggested program improvements and/or program deficiencies.

The Progress Energy Quality Assurance Program Manual, NGGM-PM-0007, requires that assessments be performed at nuclear plants and company locations where functions affecting safety-related activities are performed. In addition, assessments are regularly scheduled on the basis of the status and safety importance of the activity being performed. These assessments verify compliance, determine the effectiveness, and evaluate the Quality Assurance Program against performance objectives and Quality Assurance Program requirements. The assessment frequencies are based on the Technical Specifications, (U)FSAR commitments, and Quality Assurance Program Manual requirements. The program manual states that assessments focus on areas of potential improvement based on indicators such as previous assessment data, industry experience, regulatory sensitivity, and input from management.

RAI B.2.2-3

The applicant stated in its application that it has developed a new program to address one time inspections to demonstrate the adequacy of the water chemistry controls. Please discuss the criteria that were used to select which piping will be evaluated to confirm the effectiveness of the Water Chemistry Program.

RNP Response:

The Water Chemistry Aging Management Program notes that the GALL identifies a number of instances where the one-time inspections are prescribed to verify the effectiveness of water chemistry in managing aging effects. A one-time inspection will be performed at representative locations for each of the line items identified by GALL. Inspections will include internal visual or volumetric, as required, to determine if loss of material or cracking has occurred. The results of these inspections will be used to assess the condition of the components in question, and will be reviewed against assumptions made regarding the effectiveness of water chemistry controls in support of license renewal.

Acceptance criteria will be based on construction codes, manufacturer's recommendations, engineering evaluations, or metallurgical examinations, as appropriate.

RAI B.2.4-1

Page B-14 of the LRA, first paragraph. The applicant stated that the Steam Generator Tube Integrity Program is performed under the "overall" steam generator program at the Robinson Nuclear Plant (RNP). Please discuss in detail the "overall" steam generator program and, in particular, the Steam Generator Tube Integrity Program at RNP.

RNP Response:

The Steam Generator Program, PLP-114, is a RNP specific program incorporating the guidance of NEI 97-06, "Steam Generator Program Guidelines." The Steam Generator Program envelopes the Steam Generator Tube Integrity Program, as described in Gall Section XI.M19.

RAI B.2.4-2

The applicant presented a table of relevant steam generator components with associated aging effects and aging mechanisms on page B-14 of the LRA. The staff has the following questions:

A. Please clarify whether the aging effects and mechanisms listed in the table are taken from actual degradation observed at RNP, potential degradation, or generic degradation.

B. Please discuss the current and past degradation in the RNP replacement steam generators.

C. Please discuss how the degraded steam generator components have been and will be dispositioned.

D. Please discuss the type and vendor of tube plugs.

RNP Response:

A. The aging mechanisms listed in the table are representative of potential aging effects/mechanisms.

B. There has been no indication of corrosion related degradation in the RNP steam generator tubes to-date. There have been a total of 19 steam generator tubes plugged through November 2002. Four of these were preventatively plugged due to probe restriction. (The tubes were plugged due to inability to pass a qualified probe. No active degradation was detected prior to plugging.) Five tubes were plugged due to loose part indication. The remaining ten tubes were plugged due to wear indications.

C. The Corrective Action Program would address degraded steam generator components.

D. One plug consists of a Westinghouse Alloy 600 mechanical plug with Alloy 690 plug-in-plug (PIP). The remaining plugs are Combustion Engineering Alloy 690 mechanical roll plugs.

RAI B.2.4-3

Page B-14. By a letter dated March 16, 1998, the applicant responded to NRC Generic Letter 97-05, "Steam Generator Tube Inspection Guidelines." In the letter, the applicant stated that it is committed to implement the guidance of NEI 97-06 with exceptions. The staff has the following questions:

A. The applicant needs to clarify whether it will follow NEI 97-06 during the extended period of operation because the applicant's commitment to NEI 97-06 made in the March 16, 1998, letter was part of a response to GL 97-05 only. That commitment was not in the spirit or regulatory framework of the LRA.

B. NEI 97-06 has been revised since the applicant responded to GL 97-05 on March 16, 1998, and will be revised in the future. Discuss whether the steam generator tube integrity program will follow the NEI 97-06 version published at the time of the extended period of operation.

C. If the applicant commits to NEI 97-06 as a part of LRA application, the applicant needs to discuss whether it will take any exception(s) to NEI 97-06.

RNP Response:

RNP is currently utilizing the guidance of Revision 1 of NEI 97-06. RNP will continue to evaluate and implement new guidance provided by future revisions of NEI 97-06. RNP will evaluate the details of new revisions to NEI 97-06 as they are released to determine if exceptions are needed. The process of evaluating changes to the Steam Generator Tube Inspection Program will continue during the period of extended operation.

As a result of the above, the following statement will be added to LRA, UFSAR Supplement, Appendix A, Subsection A.3.1.4, Steam Generator Tube Integrity Program:

> "As part of the existing program, RNP will evaluate the details of new revisions to NEI 97-06 as they are released to determine if exceptions are needed. The process of evaluating changes to the Steam Generator Tube Inspection Program will continue during the period of extended operation."

RAI B.2.4-4

In the March 16, 1998, letter, the applicant discussed two exceptions to NEI 97-06. Exception number 2 is related to NEI 97-06, section 2.2, "Accident-Induced Leakage Performance Criterion." In the letter, the applicant stated that the RNP Updated Final Safety Analysis Report (UFSAR) does not calculate radiological doses to the control room; therefore, the NEI 97-06 leakage performance criterion will only be applied to radiological dose calculations contained in applicable analyses in the UFSAR. The staff is not clear whether the applicant will take the same exception under the LRA. If this exception will be taken in the LRA, the staff has the following questions:

A. Please explain what applicable analyses in the UFSAR that was referenced.

B. Please explain in terms of NEI 97-06 specifications or licensing design basis why it is acceptable that radiological doses to the control room are not calculated.

C. Please describe the condition monitoring assessment and operational assessment that will be performed in terms of leakage calculations and radiological doses calculations during the extended period of operation.

RNP Response:

A. Steam generator tube leakage is an input to the Main Steam Line Break Analysis, which is described in UFSAR Section 15.1.5.

B. Radiological doses to control room operators as a result of an accident are described in UFSAR Section 15.6.5.5.4. Additionally, RNP has requested Technical Specifications changes and a revised radiological source term in accordance with 10 CFR 50.67.

C. Condition monitoring and operational assessments are performed in accordance with EPRI TR-107621, "Steam Generator Integrity Assessment Guideline." An assessment of tube integrity is performed after each steam generator inspection. Primary-to-secondary leakage is limited, consistent with Technical Specifications 3.4.13.

RAI B.2.4-5

The applicant stated that ". . . RNP steam generator tube integrity program is continually upgraded based on industry experience and research via the Operating Experience and Self-Assessment Programs. . .."

A. Please describe in detail how the Steam Generator Tube Integrity Program is upgraded via the Operating Experience and Self-Assessment Programs.

B. Please describe in detail the Operating Experience and Self-Assessment Programs.

RNP Response:

A. The Operating Experience Program and the Self-Assessment Program contribute to upgrading of the Steam Generator Tube Integrity Program by identifying and recommending program improvements. Additional details regarding Operational Experience and Self-Assessment Programs is provided below.

B. The Operating Experience and Self-Assessment Programs were described in Attachment D of the RNP submittal entitled, "Response to Request for Additional Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information," dated February 11, 1997. Pertinent details from that submittal are summarized as follows.

"The Operating Experience Program provides the process for assessing operating experiences from industry sources for possible impact on the operation of CP&L nuclear plants, and it provides the mechanism for the sharing of OE information among CP&L's nuclear sites. Where action is required, corrective actions are initiated to eliminate or reduce the probability of similar incidents. The program also disseminates appropriate information of importance to affected groups.

The OE Program includes, but is not limited to:

1) Applicable INPO operating experience reports and documents;
2) NRC INs and other applicable documents;
3) Significant Adverse Condition Reports generated within the company.

The program provides for source document receipt, processing (screening, evaluation, action tracking), and record maintenance of OE item disposition. It designates responsible personnel to help assure that operational type information originating both from within and outside the

company is screened, disseminated, and actions are tracked. It also identifies personnel responsible for helping ensuring that those items screened for evaluation are forwarded to cognizant plant personnel.

The Self-Assessment Program requires individual line organizations to develop annual self-assessment plans and approve completed self-assessments. Self-assessment topics are determined based upon criteria such as identified weaknesses, impact on nuclear safety, and program or process changes. Details of the assessment process, including the requirements for planning, preparation, conduct, and reporting of results to management, are proceduralized.

RAI B.2.4-6

Please discuss how steam generator tube leakage integrity is managed (i.e., what is the shutdown criteria when a leak occurs and what guidance is used) and describe in detail how tube leakage is monitored at RNP.

RNP Response:

The shutdown criterion is leakage greater than or equal to 150 gallons per day through any one steam generator.

Primary-to-secondary leakage may be detected by the radiation monitoring system or by secondary sample analysis. Steam generator samples are analyzed daily for principal gamma emitters and tritium. Gamma emitter activity levels above background indicate a probable leak. When a primary-to-secondary leak is indicated, its magnitude can be determined through secondary coolant chemical analysis.

RAI B.2.4-7

Please provide all steam generator components that are covered under the Steam Generator Tube Integrity Program other than those components that have been provided in the table on page B-14.

RNP Response:

The Steam Generator Tube Integrity Program is credited with aging management of Component Commodity Group Items 15 and 17 of Table 3.1-1, and Item 3 of Table 3.1-2, of the LRA.

RAI B.2.6-1

In LRA Section B.2.6, "ASME Section XI, Subsection IWF Program," it is stated that in the evaluation of the IWF program against the program elements of the GALL Report, exceptions to Code requirements that have been granted by approved relief requests were not considered to be exceptions to the GALL criteria. Please explain what those relief requests are, and the basis for your determination to not consider them as exceptions to the GALL criteria.

RNP Response:

The current RNP ISI Program is based on repeated 10-year inspection intervals in accordance with the ASME Code and associated regulatory requirement. During the license renewal period of extended operation, the ISI Program will continue to perform its inspection requirement and will be subject to the same requirements prescribed by the ASME Code and associated regulations.

Currently, where conformance with a Code requirement has been considered impractical, the Code (10 CFR 50.55a(f)(5)(iii)) permits the licensee to notify the Commission of this condition and submit the relevant information to support the determination. Therefore, the Commission reviews, approves, or otherwise dispositions relief requests from ASME Code requirements submitted by a licensee. Where considered impractical or a burden to a facility, relief from Code requirements will continue to be submitted for approval during the period of license renewal extended operation.

The RNP Fifth Ten-Year ISI Interval begins on February 19, 2012. Similar to the Fourth Ten-Year Interval, the ISI Program will be developed and prepared to meet the ASME Code requirements as prescribed in 10 CFR 50.55a. The program may also contain relief requests, and the Commission, on the same basis as for the 40-year license, will review these relief requests. Relief requests are plant specific and the generic GALL document does not address them. Since, relief requests receive NRC approval prior to implementation, they effectively represent approved code deviations, and therefore, are not considered to be exceptions to the GALL criteria.

RAI B.2.6-2

LRA Section B.2.6, "ASME Section XI, Subsection IWF Program," listed loss of material due to general corrosion to be the only aging effect/mechanism of concern. It also stated that the IWF program examines hangers for loss of mechanical function; however, loss of mechanical function was not identified as an age-related degradation in the RNP aging management review. Please elaborate on the extent the hangers are examined for loss of mechanical function, following the IWF program, and explain why loss of mechanical function for hangers was not identified as an age-related degradation in the aging management review. Please note that in GALL, Section XI.S3, "ASME Section XI, Subsection IWF Program," under *Parameters Monitored or Inspected*, it is stated that VT-3 visual examination will be used to monitor or inspect component supports for corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close tolerance machined or sliding surfaces, and missing, detached, or loosened support Items. In addition, the GALL program states that the visual examination would be expected to identify relatively large cracks. Discuss how your IWF program was considered to be consistent with the GALL IWF program, considering conformance of all relevant program elements.

RNP Response:

The RNP Aging Management Review (AMR) for IWF Program component supports concluded that the only effect/mechanism of concern was loss of material due to general corrosion. The loss of mechanical function concerns for component supports were addressed in the AMR, but their occurrence could not specifically be attributed to aging. A review of the potential loss of component support intended functions determined that they could be design-related, or due to an unplanned plant operational occurrence, but not to aging. Missing, detached, or loosened support items could also not be attributed to aging. This question and response for RNP is similar to ANO-1 RAI 3.3.6-22 and has been accepted as documented in NUREG-1743, "Safety Evaluation Report, Related to License Renewal of Arkansas Nuclear One, Unit 1." These conclusions were further verified by review of RNP plant reports for component support deficiencies, which did not indicate that such deficiencies are due to aging.

However, the RNP IWF Program for component supports currently requires them to undergo periodic inspections, and the program examines supports for loss of material due to general corrosion and loss of mechanical function. Although not a requirement for license renewal, the program examines supports for loss of mechanical function in accordance with Table IWF-2500-1 (1989 Edition) as follows:

- (F1.10) Mechanical connections to pressure-retaining components and building structure
- (F1.20) Weld connections to building structure
- (F1.30) Weld and mechanical connections at intermediate joints in multi-connected integral and non-integral supports
- (F1.40) Clearances of guides and stops, alignment of supports, and assembly of support items
- (F1.50) Spring supports and constant load supports
- (F1.60) Sliding surfaces
- (F1.70) Hot and cold position of spring supports and constant load supports

The RNP IWF Program provides for visual examination (VT-3) of the Class 1, 2, and 3 component supports. There are no Class MC Component supports at RNP.

The aging management of ASME Class 1, 2, and 3 component supports will continue to be managed by the RNP IWF AMP for loss of material due to corrosion, as well as loss of mechanical function. RNP further confirms that IWF AMP will be implemented consistently with the requirements of 10 CFR 50.55a throughout the period of extended operation, thereby satisfying the requirements for the aging management of ASME Class 1, 2, and 3 component supports.

RAI B.2.7-1

The applicant credits the 10 CFR Part 50, Appendix J Program for aging management of selected components in the reactor containment building at RNP. The applicant identifies the aging effects/mechanisms of concern as: (1) cracking due to elevated temperature, (2) cracking due to thermal fatigue, (3) change in material properties due to elevated temperature, and (4) loss of material due to general corrosion, wear, aggressive chemical, crevice corrosion, galvanic corrosion, and pitting. A number of degradations cited above cannot be readily detected by performing leakage rate tests as described in GALL Section XI.S4, "10 CFR Part 50, Appendix J." Please provide a clear description of the purpose of the program that would be consistent with GALL Section XI.S4, or develop the ten elements of the program that would be consistent with the intended use of the program. In the later case, please provide information as to how the leaktight integrity of the containment will be maintained during the extended period of operation.

RNP Response:

The RNP Appendix J Program is consistent with GALL Section XI.S4. The Appendix J Program is used to detect degradation of components that compromise the containment pressure boundary including: the containment liner, mechanical (including fuel transfer tube) and electrical penetrations, equipment hatch, personnel airlock, mechanical penetration bellows, and seals and gaskets for the personnel airlock and equipment hatch. Each of the aging effects described in the RAI could affect leakage and were determined to be applicable to the Appendix J Program as follows:

- Cracking of seals and gaskets due to elevated temperature
- Cracking of penetration bellows due to thermal fatigue
- Cracking of certain hot pipe penetration without bellows due to thermal fatigue
- Change in material properties of seals and gaskets due to elevated temperature
- Loss of material of containment liner, penetrations, personnel airlock, equipment hatch, and mechanical penetration bellows from any of the aging mechanisms described above in the RAI

In addition, the RNP ASME Section XI, Subsection IWE Program, is consistent with GALL Section XI.S1 with enhancements as described in the LRA Section B.3.13. The IWE Program performs visual inspections as described below:

- Cracking of penetration bellows inside containment due to thermal fatigue
- Cracking of certain hot pipe penetrations without bellows due to thermal fatigue
- Loss of material of containment liner, penetrations (including fuel transfer tube), personnel airlock, equipment hatch, and mechanical penetration bellows (inside containment) from the aging mechanisms described in the RAI above

The 10 CFR Part 50, Appendix J Program and the ASME Section XI, Subsection IWE, Program will continue to be utilized during the extended period of operation. Together, these programs assure that the degradation mechanisms cited in the RAI will be adequately detected and managed.

RAI B.2.7-2

In the element *Scope of Program* of GALL Section XI.S4, "10 CFR Part 50, Appendix J," the program provides an option for leakage testing of containment isolation valves: (1) under Appendix J, Type C test, or (2) along with the tests of the systems containing isolation valves. Please provide information as to which of the options is being used and will be used during the extended period of operation.

RNP Response:

RNP currently performs Appendix J, Type C tests on containment isolation valves at intervals prescribed by and in accordance with the requirements of 10 CFR 50, Appendix J. While there are no plans to change the method of testing in the near future, the RNP Appendix J Program is continually upgraded based on industry experience and research. Additionally, improved technology or techniques may result in the adoption of different leakage testing techniques during the extended period of operation. Any such changes are expected to involve a license amendment request, or will otherwise be controlled in accordance with 10 CFR 50.59 and/or applicable plant procedures.

RAI B.2.7-3

Under *Operating Experience*, the applicant states, "Several Condition Reports have been generated as a result of as-found conditions or as a result of assessments (site and corporate)." Please provide a summary of condition reports where significant as-found leakages (Type A, Type B, and Type C tests) were found (e.g., more than twice the acceptance criteria), including the corrective action taken. The staff requires this information to assess the soundness of the implementation of this existing program.

RNP Response:

A review of the Corrective Action Program database identified no specific conditions where as-found leakages were greater than twice the acceptance criteria. Those as-found conditions cited in the license renewal application involve generic issues, such as using instruments with the wrong calibrated range, assessment findings of more desirable valve line-ups, or more desirable testing configurations. Two instances involved findings that containment purge isolation valve V12-8 had exceeded its leakage acceptance criterion by a small margin, however, the condition was resolved by establishing that the original acceptance criterion was overly restrictive.

RAI B.2.7-4

In the summary description of the program, provided in Section A.3.1.7 of the UFSAR Supplement, the applicant characterized the program as consisting of inspections of accessible surfaces of containment and monitoring of leakage rates through the containment pressure boundary. Moreover, the LRA states that the program is implemented in accordance with 10 CFR Part 50, Appendix J, Regulatory Guide (RG) 1.163, and NEI 94-01, Rev. 0. These documents provide generic requirements (in Appendix J) and guidance (in NEI 94-01 and RG 1.163). The RNP containment related acceptance criteria and basis for leak rate testing are included in plant technical specifications. The UFSAR, in general, is a plant specific report of applicant's commitments. Please provide justification for not referencing the plant specific technical specification requirements and acceptance criteria in the UFSAR Supplement.

RNP Response:

The Technical Specifications are part of the plant Operating License and must be met, independent of statements provided in other CLB documents. Therefore, referencing of Technical Specifications requirements within the UFSAR Supplement is unwarranted.

RAI B.2.8-1

LRA Section B.2.8, Flux Thimble Eddy Current Inspection Program, states volumetric examination techniques will be used to monitor for vibration-induced wear in the incore flux thimble tubes; however, the name of the aging management program implies that eddy current testing techniques (ET) will be used to monitor for vibration-induced wear in the incore flux thimble tubes. If other volumetric inspection methods may be used as alternatives to ET, please state what the inspection techniques are and how the inspection techniques are qualified to monitor for vibration-induced wear of the incore flux thimble tubes.

RNP Response:

Eddy current testing is the technique currently used to implement NRC Bulletin 88-09 requirements for determining the amount of wear on flux thimble tube walls. Other volumetric inspection methods are not currently credited as alternatives to eddy current testing.

RAI B.2.8-2

In the applicant's [Operating Experience] program attribute, it is stated that it identified two incore neutron flux thimble tube leakage events. However, the applicant did not describe these events. Please discuss how this operating experience has been incorporated into the [detection of Aging Effects], [Monitor and Trending], and [Acceptance Criteria] program attributes for the Flux Thimble Eddy Current Inspection Program, as supplemented with the additional information provided in the CP&L response to NRC Bulletin 88-09, dated February 8, 1991.

RNP Response:

The two documented incore flux thimble tube leaks were identified on tubes F-13 and J-07 during 1996 and 1999, respectively. The leakage from F-13 was discovered when RCS coolant was found in the associated tube during eddy current testing, and the leak in J-07 was found after an annunciator activated from water accumulating on the seal table from a slow leak.

While the actual cause and type of degradation for F-13 is unknown, eddy current testing of F-13 indicated 87% wear-through in the vicinity of the fuel assembly bottom nozzle, which implies some type of debris-induced fretting. This was determined to be an isolated event and is not indicative of general degradation associated with the incore flux thimbles.

The cause and type of degradation for J-09 could also not be determined. Since eddy current testing revealed no wear for the tube attributed to the leakage, this occurrence is attributed to a microscopic through-wall crack. This is also considered an isolated event and not indicative of any general degradation associated with the incore flux thimbles.

F-13 was capped and removed from service. The leakage attributed to J-07 was determined to be insignificant, so the tube was isolated but remains in service. The eddy current test procedure was revised to caution the user that tube J-07 may contain water due to the leak and that appropriate care should be exercised at the beginning of testing for this tube. This was determined to be the only enhancement required to the flux thimble eddy current testing program as a result of these events.

RAI B.2.8-3

To ensure that the UFSAR supplement description for the Flux Thimble Eddy Current Inspection Program is cross-referenced to the CP&L response to NRC Bulletin 88-09, amend the UFSAR supplement description for the Flux Thimble Eddy Current Inspection Program to reflect that the information provided in the CP&L response to Bulletin 88-09, dated February 8, 1991, provides additional details regarding the frequency of examinations to be performed, the acceptance criteria for evaluating any flaws that may be detected, and inspection methodology to be used for the examinations.

RNP Response:

The UFSAR Supplement, Appendix A, Section A.3.1.8, description of the Flux Thimble Eddy Current Inspection Program will be modified by the following sentence:

> "Additional details regarding examination frequency, flaw acceptance criteria, and inspection methodology are provided in theRNP letter from G. Vaughn (CP&L) to NRC, Serial NLS-91-024: "Response to NRC Bulletin No. 88-09," dated February 8, 1991."

RAI B.3.2-1

There is no discussion of strategies that address boric acid leak management for component segments that are inaccessible to visual inspection at the RNP. Discuss whether there are provisions in the boric acid corrosion program to inspect, detect, or monitor boric acid leakage in inaccessible locations.

RNP Response:

RNP's response to NRC Bulletin 2002-01, provided by letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0041: "Submittal of Information Requested by NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated April 01, 2002, provides a description of pertinent aspects of the RNP Boric Acid Corrosion Program, as follows:

Visual examinations may be conducted without removal of insulation. However, for leakage examinations of components with external insulation surfaces and joints not accessible for direct visual examination, the surrounding area (including the floor, equipment surfaces underneath the inaccessible component, and other areas where leakage may be channeled) shall be examined for evidence of component leakage.

Discoloration, staining, boric acid residue, and other evidence of leakage on insulation surfaces and the surrounding area shall be given particular consideration as evidence of component leakage. If evidence of leakage is found, removal of insulation to determine the exact source may be required.

When leakage is discovered, the leak/spray path shall be investigated, removing insulation as necessary, to determine the extent of any component degradation.

RAI B.3.2-2

NRC Generic Letter (GL) 88-05 provides guidance on monitoring the condition of the reactor coolant pressure boundary for borated water leakage. NRC Information Notice 86-108 and three supplements give information on degradation of reactor coolant system pressure boundary resulting from boric acid corrosion. The applicant did not address the safety concerns in GL 88-05 or Information Notice 86-108 in section B.3.2 of the LRA. Please discuss whether the boric acid corrosion program at RNP is consistent with GL 88-05 and whether the program addresses the concerns in Information Notice 86-108.

RNP Response:

GL 88-05

The RNP LRA, UFSAR Supplement, Appendix A, Subsection A.3.1.10, notes that the Boric Acid Corrosion Program was implemented in response to NRC GL 88-05.

The RNP response to NRC Bulletin 2002-01, submitted by letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0041: "Submittal of Information Requested by NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated April 1, 2002, provides a discussion of the RNP Boric Acid Corrosion Program relative to GL 88-05 requirements. As discussed in the referenced letter:

"RNP maintains a program for the implementation of NRC GL 88-05. This program is implemented by program and surveillance procedures. Effective implementation of these program procedures was demonstrated during Refueling Outage (RFO)-20 in response to the identification of a CRDM canopy seal weld leak. These program and surveillance procedures are consistent with NRC GL 88-05."

The program procedure outlines specific activities and inspection boundaries, and supplements the requirements of other surveillances for the inspection and disposition of borated system leakage and any resultant corrosion of primary pressure boundary "targets," including other safety-related components.

IN 86-108

NRC GL 88-05 summarizes various reported incidents of boric acid corrosion of reactor coolant system pressure boundary components, including the incidents described in IN 86-108 through Supplement 2. RNP implementation of NRC GL 88-05 provides the basis for concluding that the RNP program addresses IN 86-108 through Supplement 2.

IN 86-108 Supplement 3, discusses boric acid corrosion of threaded fasteners at Calvert Cliffs Unit 1 and Three Mile Island Unit 1. IN 86-108, Supplement 3, concludes:

> *"The primary defense against boric acid corrosion, previously discussed in Information Notice 86-108, remains the same; i.e., minimize leakage, detect and stop leaks soon after they start, and promptly clean up any boric acid residue."*

The conclusion of IN 86-108, Supplement 3, remains the same as the original notice and supplements. Therefore, RNP implementation of NRC GL 88-05 provides the basis for concluding that the RNP program addresses IN 86-108 through Supplement 3.

RAI B.3.2-3

The NRC has issued Generic Letter 97-01, Bulletins 2001-01, 2002-01, and 2002-02 regarding reactor vessel head degradation caused by boric acid leakage. Discuss any steps that have been taken in the RNP Boric Acid Corrosion Program to reflect the staff's concerns and recommendations in the aforementioned NRC generic communications. (It should be noted that Bulletins 2001-01 and 2002-02 are focused on reactor vessel head inspection)

RNP Response:

GL 97-01

GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," was issued to request licensees to describe their program for insuring the timely inspection of CRDM and other closure head penetrations. The following responses provide RNP information relative to the information requested by the GL:

> RNP letter from T. Wilkerson (CP&L) to NRC, Serial RNP-RA/97-0167: "Submittal of Information Requested by GL 97-01, 'Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,'" dated July 29, 1997; and
>
> RNP letter from R. Warden (CP&L) to NRC, Serial RNP-RA/99-0024: "Response to Request for Additional Information GL 97-01, 'Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,'" dated February 1, 1999

Further discussion regarding this matter is also included in the RNP Response to RAI B4.1-1.

No revision to the boric acid corrosion program was indicated by the subject correspondence.

Bulletin 2001-01

NRC Bulletin 2001-01,"Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," requested information related to the structural integrity of the reactor VHP nozzles, including the extent of VHP nozzle leakage and cracking that has been found to date, the inspections and repairs that have been undertaken to satisfy applicable regulatory requirements, and the basis for concluding that plans for future inspections will ensure compliance with applicable regulatory requirements.

The following responses provide RNP information relative to the information requested by the Bulletin:

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0133: "Submittal of Information Requested By NRC Bulletin 2001-01, 'Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,'" dated September 4, 2001

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0153: "Supplemental Information Regarding NRC Bulletin 2001-01, 'Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,'" dated October 2, 2001

Letter from B. L.Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0161: "Supplemental Information Regarding NRC Bulletin 2001-01, 'Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,'" dated October 19, 2001

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0170: "Supplemental Information Regarding NRC Bulletin 2001-01, 'Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,'" dated November 12, 2001

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0175: "Submittal of Results of Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspections Performed during Refueling Outage-21,'" dated December 13, 2002

The following steps were taken to satisfy the recommendations in the subject Bulletin:

- RNP responded to NRC Bulletin 2001-01, by letter dated September 4, 2001, and provided supplements to this submittal to demonstrate that RNP was in compliance with applicable regulatory requirements, and to provide assurance regarding the structural integrity of VHP nozzles. The RNP supplement, dated November 12, 2001, committed that a plan for non-destructive examination of the RNP VHP nozzles would be provided to the NRC staff at least 60 days prior to the start of Refueling Outage-21.

- The September 4, 2001, RNP correspondence indicated that during the RO-20 in May 2001:

    - Extensive visual examinations of the reactor vessel head were performed.

- The reactor vessel head shroud and insulation were removed for these visual examinations resulting in the performance of a bare-metal visual examination.

- Additionally, in support of these visual examinations, cleaning of the reactor vessel head was performed.

- No evidence of VHP nozzle leakage or any other sources of reactor coolant system pressure boundary leakage were identified. The effort expended during RO-20 to clean and visually examine the reactor vessel head provides a sound baseline for future examinations.

Further detailed discussion is provided in the aforementioned docketed correspondence.

No revision to the boric acid corrosion program was indicated by the subject correspondence.

Bulletin 2002-01

RNP responded to the subject Bulletin via the following correspondence:

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0041: "Submittal of Information Requested By NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated April 1, 2002

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0072: "Submittal of 60 Day Response to NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated May 17, 2002

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0182: "Submittal of 30 Day Response to NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated December 13, 2002 (Note: this is a 30-day post-outage response following head inspection)

The following steps were taken to satisfy the request for information in the subject Bulletin:

- Information related to the integrity of the reactor coolant pressure boundary, including the RPV head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements.

- The basis for concluding that RNP satisfies applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary, and the extent that future inspections will ensure continued compliance with applicable regulatory requirements.

- The basis for concluding that the boric acid inspection program is providing reasonable assurance of compliance with the applicable regulatory requirements discussed in GL 88-05 and the Bulletin.

- The results of the bare-metal qualified visual examination determined that the 69 VHP nozzles were acceptable with no degradation, cracking, or leakage identified. No degradation of the RPV head was identified. Therefore, no corrective action or root cause determinations were necessary.

Further detailed discussion is provided in the aforementioned docketed correspondence.

No revision to the boric acid corrosion program was indicated by the subject correspondence.

Bulletin 2002-02

RNP responded to the subject Bulletin via the following correspondence:

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0122: "Reactor Vessel Head Inspection Plan for Refueling Outage-21," dated August 12, 2002

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0126: "Submittal of Information Requested by NRC Bulletin 2002-02, 'Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,'" dated September 9, 2002

Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0175: "Submittal of Results of Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspections Performed during Refueling Outage-21,'" dated December 13, 2002

The following information was provided as requested in the subject Bulletin:

- RNP plans to supplement the RPV inspection program with non-visual NDE methods. The RNP RPV inspection plan for the RO-21 was provided to the NRC by letter dated August 12, 2002.

- The schedule and frequency for NDE examinations during future refueling outages, i.e., refueling outages subsequent to RO21, will be established following careful review of such factors as the RO-21 inspection results; industry information that becomes available as similar examinations are completed at other facilities; improvements in industry understanding of examination techniques and crack growth rates; and, the possibility of procuring a replacement RPV head for HBRSEP, Unit No. 2.

- The bare-metal qualified visual examination of the RPV head and head penetration nozzles did not identify evidence of VHP nozzle leakage or cracking.

- The NDE of the RPV head penetration nozzles found no evidence of service-related degradation.

Further detailed discussion is provided in the aforementioned docketed correspondence.

No revision to the boric acid corrosion program was indicated by the subject correspondence.

RAI B.3.2-4

The applicant stated that as a result of the license renewal review, the scope of the Boric Acid Corrosion Program will be enhanced to identify additional areas in which components may be susceptible to exposure from boric acid (e.g.,containment, auxiliary, and spent fuel buildings).

A. Please provide a list of specific areas (i.e., buildings) that will be covered by the boric acid corrosion program.

B. Please specify which piping systems and components that will be covered in the boric acid corrosion program.

C. Please describe the boric acid corrosion program.

RNP Response:

The RNP Boric Acid Corrosion Control Program is described in detail in the following docketed correspondence:

> Letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0072: "Submittal of 60 Day Response to NRC Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated May 17, 2002

Also, refer to Part A of the RNP Response to RAI B3.10-10 for additional information in this regard.

RAI B.3.2-5

The applicant stated that boric acid leakage from the pressurizer is managed by boric acid corrosion program and the ASME Code. Address why the steam generators and reactor pressure vessel are not included in the Boric Acid Corrosion Program.

RNP Response:

The statement regarding the pressurizer was not intended to limit the scope of the program only to the pressurizer. The steam generators and reactor pressure vessel are included in the Boric Acid Corrosion Control Program. Please refer to Item 26 in LRA Table 3.1-1.

RAI B.3.3-1

Please discuss flow-accelerated corrosion (FAC) problems that have occurred in RNP. Describe the current FAC program. Discuss the effectiveness of the FAC program in resolving the past FAC occurrences.

RNP Response:

The purpose of the Flow Accelerated Corrosion Program is to develop a standardized method of identifying, inspecting, and evaluating piping systems that are susceptible to FAC.

This program satisfies a regulatory commitment made by CP&L to the NRC, in response to NRC Bulletin 87-01 and NRC GL 89-08, regarding implementation of a long-term FAC Monitoring Program.

Under the RNP FAC Program plant systems were reviewed for susceptibility. In general, secondary (steam cycle) systems are considered susceptible to FAC wear, except those that are stainless steel. Alloy piping with chromium content greater than 1% is ten times more resistant to FAC than carbon steel, but such piping has been included in the initial program until the expected low wear rates are verified. The RNP FAC Program is credited to manage aging effects for components within the following systems within the scope of license renewal (including components identified as in scope per 10 CFR 54.4(a)(2)):

- Steam generator blowdown system
- Main steam
- Extraction steam system
- Auxiliary boiler/steam system
- Feedwater system
- Heater vents, drains, and level control
- Condensate system
- Steam generators
- AFW

The RNP FAC Program is based on the criteria identified in NSAC-202L-R2 as recommended by GALL. As stated in LRA Subsection B.3.3, the FAC Program (with identified enhancements) is consistent with GALL Section XI.M17, Flow Accelerated Corrosion. This determination is based on an evaluation of the site FAC Program with respect to each of the GALL program elements discussed in Section XI.M17.

Several problem areas have been identified at RNP as a result of the FAC Program, including wall thinning of pipe due to FAC in the following areas:

- High-pressure steam extraction lines – 100% of this piping was replaced with FAC-resistant piping (stainless steel or low alloy steel)
- Reheater drains – 99% of piping replaced with FAC-resistant pipe
- Condensate system – 100% inspection coverage, with limited replacement. The system is currently subject to ongoing monitoring and trending
- Small bore drains – 100% replaced with FAC-resistant piping
- 2" blowdown piping – 100% replaced with FAC-resistant piping

The effectiveness of the FAC Program has been demonstrated by a decrease in iron transport measurements. Also, there has been no evidence of FAC-related leaks in more than two years. This is in contrast to 15 identified FAC-related leaks during the period from January 1990 to November 1999.

Another example of how the FAC Program has been effective in resolving FAC problems is documented in NRC Integrated Inspection Report No. 50-261/98-02. In this report, a specific case of wall thinning was reviewed by the NRC (SG "A" nozzle to reducer). This inspection found records of the FAC test to be complete and accurate. Problem areas were found to be properly evaluated and dispositioned by engineering.

For further information in this regard, see the RNP Responses to RAIs B.3.3-5 and B.3.3-6.

RAI B.3.3-2

The applicant stated that as a result of the license renewal review, enhancements will be made to the FAC program.

A. The applicant will added to the FAC program those components that may be susceptible to FAC or to erosion. Please identify all components and systems that are covered in the program scope.

B. Please discuss the enhancement(s) to the program elements for *Scope of Program* and *Corrective Actions.*

C. Please describe the program improvements made as a result of NRC inspections. Provide the reference of the NRC Inspection reports.

RNP Response:

A. During the AMR process, several components were identified that were not in the current site FAC Program. These components are included in the scope of the enhanced License Renewal AMP (see below). Implementation of these AMP enhancements has not yet been completed for the site programs.

B. Scope of Program

Components not specifically identified in the current site program will be added to site program documents. These components were identified during the LR AMR process and include steam nozzles, feedwater nozzles, steam generator nozzle thermal sleeves, and temperature elements (thermowells).

The FAC Program does not currently monitor for erosion. The program will be enhanced to inspect for erosion wear in locations deemed to be susceptible by the system engineer.

The FAC predictive model considers valves to be high-wear components. Downstream piping is used as a "leading indicator" for valves deemed to be susceptible to FAC wear. The FAC Program will be revised to add a section dedicated specifically to valves. An additional requirement will be added to program procedures to require material alloy analysis for potentially susceptible valves.

Corrective Actions

The RNP FAC Program procedure will be revised to state that a Condition Report "shall" be initiated in accordance with the Corrective Action Program for through-wall failures, or when actual wall thickness is found to be substantially less than the expected value.

C. An NRC inspection was performed from April 27 to May 1, 1992 (NRC Inspection Report No. 50-261/92-13). The inspector found the FAC Program to be weak with little Corporate direction. Several needed program enhancements were identified by this NRC Inspection. A follow-up NRC inspection was performed in September 1993 (NRC Inspection Report No. 50-261/93-20). The follow-up inspection noted significant program improvements.

RAI B.3.3-3

The applicant stated that ". . . administrative controls for the program will be revised to mandate that corrective actions be taken in accordance with the corrective action program when certain acceptance criteria are not met . . .."

A. Please clarify if the above statement is consistent with GALL XI.M17, "Flow-Accelerated Corrosion," because in GALL XI.M17 the administrative controls element is not related to the corrective actions element..

B. Please discuss the "certain acceptance criteria" that may not be met.

RNP Response:

A. The statement in question is referring to the LR evaluation of the Corrective Action Program element for the RNP FAC Program. The "administrative controls" delineated in the site FAC Program procedure currently state that a Condition Report "should" be initiated in accordance with Corrective Action Program procedures whenever a through-wall failure (leak) occurs. As an enhancement for the Corrective Action Program element, RNP will revise the site procedure to state that a Condition Report "shall" be initiated in accordance with Corrective Action Program procedures for through-wall failures, or when actual wall thickness is found to be substantially less than the expected value. Use of the term "administrative controls" in this statement was not meant to infer the program enhancement was for the Administrative Controls program element.

B. The "certain acceptance criteria" refers to FAC related failures, including through-wall failures, or when actual wall thickness is found to be substantially less than the expected value.

RAI B.3.3-4

The applicant stated that several condition reports have been generated as a result of as-found conditions or as a result of its assessments. Describe the condition reports.

RNP Response:

The as-found conditions and assessment results were documented and tracked within the Corrective Action Program using Condition Reports. Please refer to the RNP Response to RAI B.3.3-1.

RAI B.3.3-5

In order for the staff to evaluate the acceptability of the FAC program, the applicant should provide a list of the components in the program most susceptible to FAC. The list should include initial wall thickness (nominal), current wall thickness and the future predicted wall thickness.

RNP Response:

The goal of the RNP FAC Program is to eliminate the risk of piping failures (either leaks or minimum wall violations) caused by flow accelerated corrosion. This requires that inspections identify the pipe, inspection data analysis supports accurate remaining life predictions, and uninspected pipe is modeled or analyzed to have high confidence in predicted remaining life. Replacements are scheduled to preclude the need for reinspections.

The inspection selection process considers the predicted time to minimum acceptable wall thickness and predicted wear rates. Components with a short predicted service life are inspected first to confirm their suitability for continued service. For components previously inspected, the estimated time remaining to reach minimum acceptable wall thickness, and wear rate, may be obtained from actual inspection data. An initial population of components to be inspected is based on CHECWORKS model predictions, engineering judgment, and industry or plant events. Also included are components inspected as a result of sample expansion due to detected wear.

Below is a listing of the 100 most susceptible components from the RNP FAC Program. The components are listed in order of Lifetime Average Wear Rate. Also shown are run hours remaining to reach minimum wall thickness. (One refueling cycle equates to approximately 13,000 hours.) Piping components are identified by line listings, followed by a unique number to identify the specific piping component (e.g., ell, reducer, straight pipe, valve). For example, the component designator FW04-03 is a unique identification number for a 4 foot long 20 inch straight pipe within the pipe line FW-04. These unique identifiers are assigned to each piping component within each line listing. Components which require "no further inspection" are those piping components with a predicted remaining life greater than plant life (including life extension).

RAI B.3.3-5

FAC SUSCEPTIBLE COMPONENTS

COMPONENT	Last Insp RO	RO-14 MIN MEAS	RO-15 MIN MEAS	RO-16 MIN MEAS	RO-17 MIN MEAS	RO-18 MIN MEAS	RO-19 MIN MEAS	RO-20 MIN MEAS	RO-21 MIN MEAS	Lifetime Average W.R. mpy	After RO-22 RUN HOURS TO MIN	INSPECTION ACTION / PLAN	REPAIR OR REPLACEMENT ACTION / PLAN
HD201-1 u/s Mn	19						0.421			33.9	23,800	RO-22 INSPECTION	Previous Replacement with CrMo
HD201-1 d/s Mn	19						0.416			33.6	23,200	RO-22 INSPECTION	Previous Replacement with CrMo
HD201-1 Br	19						0.443			28.9	3,100	RO-22 INSPECTION	Previous Replacement with CrMo
FW10-45	16		1.130	1.101						27.1	100,500	RO-25 INSPECTION	
MS042B-11 u/s Mn	20			0.362				0.362		24.3	59,300	RO-22 Replacement SS	RO-22 Replacement SS
HD022-13	16		0.321	0.316						22.4	11,200	RO-22 INSPECTION	
CR03-02	17				0.598					22.3	67,000	RO-25 INSPECTION	
FW30-06	18					1.176				21.9	29,000	RO-23 INSPECTION	
HD201-1x1	19						0.294			21.1	9,700	RO-22 INSPECTION	Previous Replacement with CrMo
FW04-03	16		1.172	1.159						20.5	4,400	RO-22 INSPECTION	
MS042B-11 d/s Mn	16			0.346						20.5	20,400	RO-22 Replacement SS	RO-22 Replacement SS
FW09-52x1	20							0.882		19.1	121,400	RO-28 INSPECTION	
MS042C-09 d/s Mn	16		0.332	0.335						18.7	26,200	RO-22 Replacement SS	RO-22 Replacement SS
MS042C-09 u/s Mn	16		0.352	0.350						18.7	33,300	RO-22 Replacement SS	RO-22 Replacement SS
FW11-47	18					0.949				18.2	81,000	RO-25 INSPECTION	
ES12-19	21								0.274	17.8	39,700	RO-24 INSPECTION	
B01-B u/s Main	17				0.303					17.8	500	RO-22 Replacement SS	RO-22 Replacement SS
HD002-17R	16		0.457	0.454						17.7	70,500	RO-25 INSPECTION	

RAI B.3.3-5

FAC SUSCEPTIBLE COMPONENTS

COMPONENT	Last Insp RO	RO-14 MIN MEAS	RO-15 MIN MEAS	RO-16 MIN MEAS	RO-17 MIN MEAS	RO-18 MIN MEAS	RO-19 MIN MEAS	RO-20 MIN MEAS	RO-21 MIN MEAS	Lifetime Average W.R. mpy	After RO-22 RUN HOURS TO MIN	INSPECTION ACTION / PLAN	REPAIR OR REPLACEMENT ACTION / PLAN
HD048-02 LE u/s	20							0.375		17.6	4,400	RO-22 Replacement CrMo	RO-22 Replacement CrMo
FW11-16LE	17				0.957					17.4	25,600	RO-22 INSPECTION	
MS042B-20 u/s Mn	16			0.372						17.1	54,200	RO-22 Replacement SS	RO-22 Replacement SS
CR05-02	18					0.968				17.1	310,100	NO FURTHER INSPECT.	
FW11-30	16		1.096	1.087						16.8	85,800	RO-25 INSPECTION	
CR06-05	18					0.431				16.7	36,600	RO-24 INSPECTION	
CR05-02x1	18					0.630				16.2	144,600	RO-28 INSPECTION	
HD001-29B	16		0.349	0.332						15.9	20,000	RO-22 INSPECTION	
MS042C-10	16		0.289	0.288						15.9	16,700	RO-22 Replacement SS	RO-22 Replacement SS
FW02-02 u/s SE	15	1.823	1.866							15.8	462,900	NO FURTHER INSPECT.	
FW02-03	15	1.232	1.223							15.8	53,300	RO-24 INSPECTION	
FW07-06	20							1.143		15.8	66,700	RO-25 INSPECTION	
HD048-02 SE d/s	20							0.391		15.6	39,300	RO-24 INSPECTION	
MS042B-11Br	16			0.273						15.5	9,100	RO-22 Replacement SS	RO-22 Replacement SS
FW04-04x1	15		1.214							15.5	51,600	RO-24 INSPECTION	
ES04-11	19						0.340			15.4	18,100	RO-22 INSPECTION	
FW05-02	19						1.201			15.4	89,300	RO-25 INSPECTION	
MS042D-16 d/s Mn	16			0.327						15.1	45,200	RO-22 Replacement SS	RO-22 Replacement SS
FW12-06 d/s Mn	16		1.370	1.366						14.9	40,500	RO-24 INSPECTION	
FW09-52x2	20							0.894		14.9	169,400	RO-30 INSPECTION	
B02A-21 Br ext	17			0.323	0.321					14.9	53,800	RO-25 INSPECTION	

RAI B.3.3-5

FAC SUSCEPTIBLE COMPONENTS

COMPONENT	Last Insp RO	RO-14 MIN MEAS	RO-15 MIN MEAS	RO-16 MIN MEAS	RO-17 MIN MEAS	RO-18 MIN MEAS	RO-19 MIN MEAS	RO-20 MIN MEAS	RO-21 MIN MEAS	Lifetime Average W.R. mpy	After RO-22 RUN HOURS TO MIN	INSPECTION ACTION / PLAN	REPAIR OR REPLACEMENT ACTION / PLAN
FW03-02 u/s SE	16			1.946						14.9	554,200	NO FURTHER INSPECT.	
FW30-02x2	16			1.154						14.8	31,300	RO-23 INSPECTION	
FW11-16SE	17				0.764					14.8	20,800	RO-22 INSPECTION	
B03-B u/s Main	17				0.327					14.8	58,200	RO-25 INSPECTION	
FW03-03	16			1.259						14.8	93,900	RO-25 INSPECTION	
HD197-03 Br	20							0.356		14.6	109,800	RO-28 INSPECTION	
FW02-06	16			1.295						14.2	122,400	RO-28 INSPECTION	
MS042D-16 u/s Mn	16			0.308						14.2	41,000	RO-22 Replacement SS	RO-22 Replacement SS
ES03-11(shell)	19						1.115			14.1	71,300	RO-25 INSPECTION	
B02A-21 u/s M	17			0.364	0.350					14.1	78,700	RO-25 INSPECTION	
FW11-49x1	*16*		0.934	0.927						14.0	155,100	RO-30 INSPECTION	
FW12-06 u/s Mn	16		1.374	1.372						14.0	51,900	RO-24 INSPECTION	
HD075-02SE	17				0.280					13.8	51,800	RO-24 INSPECTION	
HD044-04	18					0.352				13.7	99,600	RO-25 INSPECTION	
FW12-04	20							1.365		13.6	99,200	RO-25 INSPECTION	
HD070-30	18		New			0.241				13.5	9,200	RO-22 INSPECTION	RO-15 Replacement A106
FW03-02 d/s LE	16			1.325						13.5	153,300	RO-30 INSPECTION	
FW02-02 d/s LE	15	1.371	1.400							13.3	259,300	NO FURTHER INSPECT.	
MS043C-02	17				0.265					13.3	31,100	RO-23 INSPECTION	
FW03-06	16			1.318						13.2	153,800	RO-30 INSPECTION	
ES02-08 (shell)	19						1.091			13.1	63,200	RO-25 INSPECTION	

RAI B.3.3-5

FAC SUSCEPTIBLE COMPONENTS

COMPONENT	Last Insp RO	RO-14 MIN MEAS	RO-15 MIN MEAS	RO-16 MIN MEAS	RO-17 MIN MEAS	RO-18 MIN MEAS	RO-19 MIN MEAS	RO-20 MIN MEAS	RO-21 MIN MEAS	Lifetime Average W.R. mpy	After RO-22 RUN HOURS TO MIN	INSPECTION ACTION / PLAN	REPAIR OR REPLACEMENT ACTION / PLAN
FW09-22x2	18					0.976				13.1	78,900	RO-25 INSPECTION	
FW11-45	*16*		0.910	0.904						13.1	156,000	RO-30 INSPECTION	
HD216-04	16		0.264	0.260						13.1	30,000	RO-23 INSPECTION	
FW07-03	17				1.254					13.0	124,100	RO-28 INSPECTION	
FW07-05	20							1.108		13.0	63,000	RO-25 INSPECTION	
FW03-05	16			1.224						12.9	95,100	RO-25 INSPECTION	
HD059-07 SE	20							0.277		12.8	95,700	RO-25 INSPECTION	
FW28-02	16	1.236	1.245	1.239						12.8	106,400	RO-28 INSPECTION	
HD075-02LE	17				0.278					12.8	59,500	RO-25 INSPECTION	
FW12-08 d/s Mn	14	1.400								12.8	63,500	RO-25 INSPECTION	
MS042D-10 d/s Mn	20							0.175		12.6	10,700	RO-22 Replacement SS	RO-22 Replacement SS
HD042-13 d/s Mn	21								0.506	12.6	216,900	RO-30 INSPECTION	
FW16-05x2	15		0.427							12.6	24,500	RO-22 INSPECTION	
HD042-13 u/s Mn	21								0.507	12.5	219,200	RO-30 INSPECTION	
FW11-04	15	0.914	0.932							12.5	22,400	RO-22 INSPECTION	
FW04-02X1	15		1.159							12.5	45,400	RO-24 INSPECTION	
HD045-02	18					0.365				12.3	25,000	RO-22 INSPECTION	
C13-25 Br	20							0.431		12.3	57,500	RO-25 INSPECTION	
FW10-33	19						0.778			12.2	116,400	RO-28 INSPECTION	
HD197-03 d/s Mn	20							0.391		12.2	160,800	RO-30 INSPECTION	
MS042B-11D	16			0.280						12.2	37,000	RO-22 Replacement SS	RO-22 Replacement SS

RAI B.3.3-5

FAC SUSCEPTIBLE COMPONENTS

COMPONENT	Last Insp RO	RO-14 MIN MEAS	RO-15 MIN MEAS	RO-16 MIN MEAS	RO-17 MIN MEAS	RO-18 MIN MEAS	RO-19 MIN MEAS	RO-20 MIN MEAS	RO-21 MIN MEAS	Lifetime Average W.R. mpy	After RO-22 RUN HOURS TO MIN	INSPECTION ACTION / PLAN	REPAIR OR REPLACEMENT ACTION / PLAN
B02-25Br	16		0.277	0.264						12.1	12,700	RO-22 Replacement SS	RO-22 Replacement SS
B02-25u/s Mn	16		0.320	0.312						12.1	32,900	RO-23 INSPECTION	
FW06-05	20							1.086		12.1	53,400	RO-24 INSPECTION	
FW04-06x3	17				1.170					12.1	77,100	RO-25 INSPECTION	
FW05-06x1	21								1.151	12.1	113,100	RO-28 INSPECTION	
FW12-08 u/s Mn	14	1.400								12.0	73,300	RO-25 INSPECTION	
HD077-02LE	17				0.280					11.9	69,500	RO-25 INSPECTION	
MS042C-16d/s Mn	20							0.316		11.9	116,500	RO-22 Replacement SS	RO-22 Replacement SS
FW09-39X2	15		0.943							11.9	198,400	RO-30 INSPECTION	
MS043C-04	19						0.201			11.7	33,700	RO-24 INSPECTION	
FW11-05	15	0.953	0.965							11.7	54,600	RO-25 INSPECTION	
HD072-Ax2	17				0.327					11.6	92,000	RO-25 INSPECTION	
MS043D-18	19						0.202			11.6	38,900	RO-24 INSPECTION	
FW14-07x1	15		0.389							11.5	6,600	RO-22 Replacement CrMo	RO-22 Replacement CrMo
FW14-07x2	15		0.419							11.5	29,400	RO-23 INSPECTION	
FW11-06	15	0.963	0.951							11.5	46,200	RO-24 INSPECTION	
FW07-02	17				1.301					11.5	184,600	RO-30 INSPECTION	
FW09-12 SE	18					0.859				11.4	130,700	RO-28 INSPECTION	
FW28-06	18					1.321				11.4	213,700	RO-30 INSPECTION	

RAI B.3.3-6

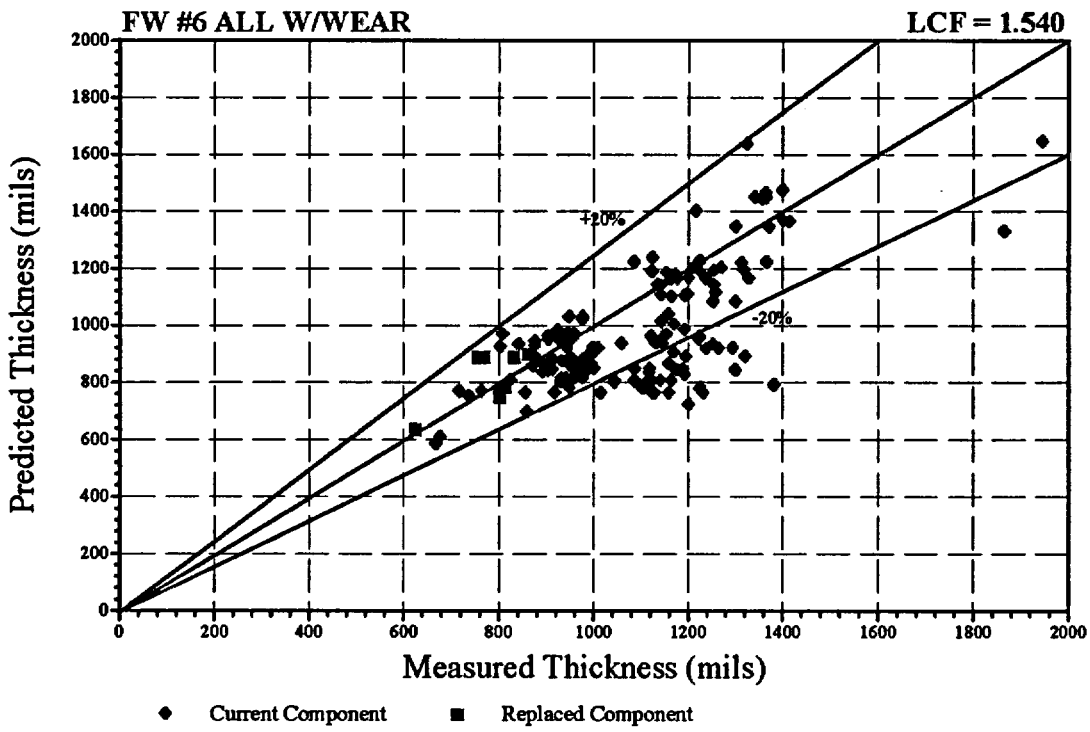
The FAC program in RNP includes prediction of the wall thinning for the components susceptible FAC. The wall thinning is predicted by the EPRI's CHECWORKS computer code. In order to allow the staff to evaluate the accuracy of these predictions, the applicant should provide a few examples of the components for which wall thinning is predicted by the code and at the same time measured by ultrasonic examination or any other measurement method employed in the RNP. This procedure will show the effectiveness of CHECWORKS in predicting the as-found condition.

RNP Response:

Below is a chart that provides comparisons of predicted versus as-found thicknesses for RNP feedwater piping. The thickness prediction is based on initial thickness (nominal wall) minus the predicted wear over the life of the component. The predicted wear is calculated initially assuming no known wear. The wear is then adjusted based on actual measurements of many components within a line. The adjustment is a correction factor which is applied to the predicted wear in the components in the line. Normally, some components will wear less than predicted and some will wear more than predicted. The line correction factor (LCF) is derived by calculating an adjustment factor for each component, then taking the median value of these individual adjustments as the line correction factor. The actual thickness measurements vary from predictions due to variations in initial pipe wall thickness, e.g., some components are substantially thicker than nominal. The data points in the non-conservative direction are a result of higher than median wear, combined with initial thickness values close to nominal.

Also provided below are data sheets from several systems within the program scope. These data sheets contain data points (in inches) for measured thickness, predicted thickness, and minimum allowable thickness.

Comparison of Thickness Predictions



Heater Drains and MSR Drains

Component Name	Measured Thickness Last Insp	Predicted Thickness Last Insp	Minimum Allowable	**Difference Between Measured and Predicted**	Difference Between Measured and Minimum Allowed	Remaining Life Hours
HD70-14 L90	0.254	0.297	0.089	**(0.043)**	0.165	1,068,514
HD1-43 L90	0.262	0.281	0.100	**(0.019)**	0.162	3,659,667
HD1-44	0.274	0.285	0.100	**(0.011)**	0.174	4,605,128
HD216-6	0.265	0.260	0.130	**0.006**	0.135	3,113,309
HD47-29 exp(S/E)	0.363	0.351	0.276	**0.012**	0.087	727,331
HD66-18 new	0.265	0.247	0.055	**0.018**	0.210	881,433
HD222-5	0.278	0.250	0.123	**0.028**	0.155	1,028,460
HD222-3	0.267	0.235	0.123	**0.032**	0.144	1,055,870
HD46-15 L90	0.341	0.305	0.212	**0.036**	0.129	693,672
HD70-27 old	0.262	0.222	0.055	**0.040**	0.207	656,447
HD48-4 L90	0.342	0.296	0.276	**0.046**	0.066	328,306
MS42C-15	0.288	0.234	0.123	**0.055**	0.165	1,184,370
HD47-7 L90	0.335	0.275	0.212	**0.060**	0.123	865,007
HD70-34 new	0.282	0.213	0.055	**0.069**	0.227	899,759
HD48-6 L90	0.362	0.282	0.276	**0.080**	0.086	572,197
HD222-14 L90	0.293	0.204	0.123	**0.089**	0.170	844,110
HD2-31 L90	0.276	0.178	0.100	**0.098**	0.176	507,474
HD68-3 redL(S/E)	0.339	0.226	0.100	**0.114**	0.239	1,187,402
HD70-36	0.265	0.147	0.055	**0.118**	0.210	830,069
MS42A-8 exp(L/E)	0.304	0.177	0.123	**0.127**	0.181	2,122,773
HD48-9 tee(U/S)	0.450	0.272	0.276	**0.178**	0.174	1,073,101
HD2-30 red(S/E)	0.343	0.159	0.100	**0.185**	0.243	895,201

Feedwater System

Component Name	Measured Thickness Last Insp	Predicted Thickness Last Insp	Minimum Allowable	**Difference Between Measured and Predicted**	Difference Between Measured and Minimum Allowed	Remaining Life Hours
FW3-2 exL(L/E)	1.325	1.636	0.977	**(0.311)**	0.348	1,233,825
FW11-35	0.809	0.963	0.562	**(0.154)**	0.247	2,260,012
FW9-1	0.842	0.932	0.782	**(0.090)**	0.060	77,839
FW12-8 Run	1.400	1.474	1.172	**(0.073)**	0.228	1,023,059
FW10-13D exp(S/E)	0.717	0.773	0.623	**(0.056)**	0.094	876,217
FW28-3	1.173	1.180	0.977	**(0.007)**	0.196	707,798
FW12-8 Branch	0.872	0.859	0.782	**0.013**	0.090	71,703
FW9-54 L90	0.801	0.765	0.749	**0.036**	0.052	145,018
FW6-2 L90	1.271	1.202	0.977	**0.069**	0.294	1,173,895
FW9-29 L90	0.856	0.765	0.799	**0.091**	0.057	158,962
FW11-17	0.977	0.875	0.782	**0.102**	0.195	1,336,476
FW9-5 L90	1.059	0.935	0.782	**0.124**	0.277	1,975,041
FW10-47 L90	0.948	0.790	0.720	**0.158**	0.228	615,423
FW11-20 L90	1.152	0.960	0.902	**0.192**	0.250	1,329,060
FW10-8 L90	1.118	0.855	0.782	**0.263**	0.336	740,928
FW10-2 L90	1.115	0.815	0.782	**0.300**	0.333	848,341
FW10-3 L90	1.124	0.815	0.782	**0.309**	0.342	874,359
FW10-5 L90	1.159	0.775	0.782	**0.384**	0.377	1,091,174
FW30-4 L90	1.301	0.847	0.977	**0.455**	0.324	322,168
FW2-2 exL(S/E)	1.866	1.333	0.879	**0.533**	0.987	697,989
FW30-1	1.382	0.796	0.977	**0.586**	0.405	192,058

Condensate System						
Component Name	Measured Thickness Last Insp	Predicted Thickness Last Insp	Minimum Allowable	**Difference Between Measured and Predicted**	Difference Between Measured and Minimum Allowed	Remaining Life Hours
C8-1 red(S/E)	0.433	0.493	0.315	**(0.060)**	0.118	2,197,609
C11-01A	0.343	0.382	0.315	**(0.039)**	0.028	603,387
C92-10 tee(BR.)	0.342	0.357	0.251	**(0.015)**	0.091	444,494
C82-3	0.499	0.506	0.394	**(0.007)**	0.105	732,931
C09-07	0.344	0.343	0.315	**0.001**	0.029	463,387
C12-6	0.354	0.347	0.315	**0.007**	0.039	494,318
C13-39	0.342	0.329	0.315	**0.013**	0.027	249,662
C84-1 tee(D/S)	0.478	0.461	0.394	**0.017**	0.084	85,012
C9-6 L90	0.350	0.328	0.315	**0.022**	0.035	361,828
C13-13	0.351	0.322	0.315	**0.030**	0.036	464,739
C13-10 L90	0.346	0.306	0.315	**0.040**	0.031	184,036
C9-4 L90	0.371	0.324	0.315	**0.047**	0.056	679,865
C23-3	0.492	0.436	0.394	**0.056**	0.098	1,026,831
C17-2	0.345	0.280	0.315	**0.065**	0.030	218,277
C22-11D	0.483	0.409	0.394	**0.074**	0.089	653,609
C15-2 L45	0.336	0.255	0.315	**0.081**	0.021	77,342
C14-2 L90	0.354	0.263	0.315	**0.091**	0.039	190,449
C18-2 L45	0.403	0.299	0.315	**0.104**	0.088	366,216
C17-07 L90	0.364	0.252	0.315	**0.112**	0.049	223,030
C14-1A	0.403	0.269	0.315	**0.134**	0.088	505,260
C14-16 noz	0.448	0.265	0.315	**0.183**	0.133	618,015
C17-8 noz	1.803	1.570	0.315	**0.233**	1.488	5,683,239
C20-3 exp(L/E)	0.960	0.686	0.591	**0.274**	0.369	3,831,769

RAI B.3.4-1

In LRA Section B.3.4, "Bolting Integrity Program," cracking is not considered as an aging effect of concern specifically identified with regard to bolting integrity. In GALL, Section XI.M18, "Bolting Integrity," cracking is identified specifically as an aging effect requiring management. Please discuss the inconsistency between the RNP bolting integrity program and its counterpart program in GALL.

RNP Response:

GALL XI.M18 discusses cracking of bolting in two applications: (1) high strength bolting on structural supports, and (2) Class 1 and 2 pressure boundary components.

At RNP, NSSS supports are the only structural supports that have a limited number of high strength bolting applications. RNP aging management evaluations have determined that these high strength bolting applications are in a benign service environment, and are not susceptible to cracking.

The RNP methodology generally treats pressure boundary bolting as a subcomponent, except in those cases where unique considerations require that it be individually subject to aging management review. Relative to cracking, a review of design and licensing documents has identified a single instance wherein "hard" (i.e., susceptible) bolting has been used in pressure boundary applications on components in the scope of license renewal. This instance has been documented in the Bolting Integrity Program, as well as LRA Table 3.3-1, Item 23. Additionally, the Bolting Integrity Program contains actions to enhance plant documents with regard to the prohibition of molybdenum disulfide.

For additional information relative to the RNP Bolting Integrity Program, see the RNP Response to RAI 3.3-2.

RAI B.3.6-1

Please provide the specific Service Class (such as CMAA Specification # 70 or # 74) to which the cranes within the scope of license renewal were designed.

RNP Response:

Polar Crane

The polar crane is considered to meet the requirements of CMAA-70. A fatigue evaluation has determined that this crane has an extremely low use factor. There was no specific service class noted.

Spent Fuel Cask Crane

The spent fuel cask crane load bearing structures and components were designed to meet the requirements of CMAA-70 for Class A1 cranes, which is for standby service cranes.

Turbine Building Crane

The Turbine Building crane was designed in accordance with the Electric Overhead Crane Institute (EOCI)-61 and American Institute of Steel Construction (AISC) 6th Edition. There was no specific service class noted.

Spent Fuel Bridge Crane

Design, fabrication, material, and erection for the spent fuel bridge crane are in accordance with the AISC Manual of Steel Construction, 1963 Edition. There was no specific service class noted.

RAI B.3.6-2

It is stated in Section B.3.6 of the LRA that enhancements will be made in the scope of the program so that the cranes will be inspected using the attribute inspection checklist for structures. Provide a summary of this attribute inspection checklist.

RNP Response:

The attribute inspection checklist for cranes/structures is as follows:

- Steel member and connection corrosion
- Damaged members or connections (deformation, tears, cracks, broken welds, loose bolts, etc.)
- Baseplate or anchor bolt corrosion
- Damaged or degraded grout pads
- Structure geometry to include excessive deflection, cross-section distortion, or member misalignment.
- Missing parts (including bolts, nuts, connectors, washers over slotted holed, etc.)
- Coating deficiencies

The attribute inspection checklist for structures does not explicitly address the subject of wear. However, the existing terminology will be enhanced to include GALL terminology, such as wear.

As a result of the above, the information in the second paragraph of LRA Subsection A.3.1.14, "Inspection of Overhead Heavy Load and Light Load Handling," is modified to note that wear will be addressed. The paragraph will read:

> "Administrative controls for Inspection of Overhead Heavy Load and Light Load Handling equipment will be enhanced, prior to the period of extended operation to: (1) include requirements for inspecting the turbine gantry crane in addition to the other cranes that require inspection, (2) note that cranes are to be inspected using the attribute inspection checklist for structures, and (3) revise the attribute inspection checklist for structures to include GALL terminology, such as wear."

RAI B.3.6-3

Please clarify whether the effects of wear on the rails will be managed, consistent with GALL Section XI.M23, "Overhead Heavy and Light Load Handling Systems," and indicate how rail wear would be managed

RNP Response:

Crane rails will be managed by the "Inspection of Overhead Heavy Load and Light Load Handling Systems Program."

Although wear was not specifically identified as an aging effect, crane rails are addressed as a structural commodity for steel member and connection corrosion and damaged members or connections (e.g., deformation, tears, cracks, broken welds, loose bolts). Additionally, existing terminology will be enhanced to include GALL terminology, such as wear (refer to the RNP Response to RAI B.3.6-2).

Only personnel trained and familiar with cranes through education and work experience can perform the inspections. Civil engineering is consulted when observed structural degradation could affect the load bearing capabilities of the crane. Conditions that do not meet the prescribed acceptance criteria are documented and corrective action applied. The crane inspection program has incorporated required program enhancements to provide reasonable assurance that the components within the scope of license renewal will continue to perform their intended functions for the period of extended operation.

RAI B.3.8-1

The applicant stated that the Buried Piping and Tanks Surveillance Program is credited for aging management of selected components in the fuel oil system. Provide a list of specific buried pipes and components that are covered in this program.

RNP Response:

"Piping and Fittings" include the following pipe line numbers:

1½-FO-36,
2-FO-21,
2-FO-58A, and
2-FO-58B

These line numbers represent carbon steel fuel oil pipe and fittings that are buried in soil or in contact with standing water.

In accordance with LRA Table 3.3-1, Item 22, the external surface of the bottoms of the tanks mounted on the ground means, the large fuel oil storage tanks, i.e., the bottoms of the following tanks are in contact with the ground - IC Turbine Fuel Oil Storage Tanks and EDG Fuel Oil Storage Tank.

RAI B.3.8-2 PART A

The applicant stated that the program elements will be enhanced to review and update cathodic protection procedures and to install pressure taps and perform leak testing on the underground fuel oil piping.

A. Please discuss the documentation of these enhancements. Discuss when will these enhancements be implemented and how can the NRC ensure the enhancements be implemented according to the LRA.

RNP Response:

Please refer to LRA UFSAR Supplement, Appendix A, Subsection A.3.1.16, which documents the commitment regarding implementation of these enhancements.

RAI B.3.8-2 PART B

The applicant stated that the program elements will be enhanced to review and update cathodic protection procedures and to install pressure taps and perform leak testing on the underground fuel oil piping.

B. Please discuss the frequency of leak testing. Discuss why the leak testing is specified for the diesel fuel oil piping but not other buried piping.

RNP Response:

Currently, fuel oil piping leak-testing is performed every two years. This testing is an enhancement to the program, since the pressure taps for the piping from the Diesel Fuel Oil Storage Tank (DFOST) to the day tanks had not yet been installed at the time of the LRA submittal. No leakage has been found in the underground piping from the Unit 1 fuel oil storage tanks to Unit 2 tanks. Based on this operating experience two years is considered a reasonable frequency for this test.

Leak testing is specified for the diesel fuel oil piping based on environmental concerns. It is not needed for the other buried piping in the scope of the inspection program discussed in LRA Section B.3.12, because the other piping are in: 1) the moderate pressure SWS which has a high flow rate of water, 2) the SFPS which is maintained at operating pressure and monitored while in standby conditions, or 3) the DSD, which is a closed coolant system and fluid inventory is monitored periodically. For further information regarding detection of leakage, please refer to the RNP Responses to RAIs B.3.12-2 and B.3.12-3 (part B).

RAI B.3.8-3

The applicant has taken several exceptions to GALL XI.M28, "Buried Piping and Tanks Surveillance" The applicant stated that it uses the guidance in NACE RP-0169-76 in lieu of NACE RP-0169-96 as recommended in GALL XI.M28. The applicant stated that it will perform enhancements to review and update, as necessary, cathodic protection procedures to ensure consistency with the 1996 NACE standards. The staff is not clear that the proposed enhancements would make the 1976 standards consistent with the 1996 standards. Provide information to show that the 1976 standards and proposed enhancements satisfy the NACE 1996 standards and NACE Standard RP-0285-95 that are recommended in GALL XI.M28.

RNP Response:

There are no buried tanks within this program. Thus, NACE Standard RP-0285-95, Corrosion Control of Underground Storage Tank Systems by Cathodic Protection, is not applicable to this program. The RNP Cathodic Protection System protects buried fuel oil system piping and the external bottom surface of fuel oil tanks that are in contact with the ground.

The planned enhancements to the program will assure consistency with the GALL Report guidelines regarding NACE Standard RP-0169-96 to the extent that this is possible with an existing cathodic protection system. The specific exceptions to the guidelines are listed in the "Conclusion" section of LRA Subsection B.3.8.

RAI B.3.8-4

GALL XI.M28 recommends that the coating conductance versus time or the current versus time be monitored to provide an indication of the coating condition and effectiveness of the cathodic protection system when compared to predetermined values. The applicant stated that in-situ measurement of coating conductance is not considered prudent due to the potential to cause coating damage. The applicant also stated that it has no documentation of initial coating conductance. Please provide parameters that will be monitored to assure the integrity of the coating on the buried pipe.

RNP Response:

As noted in the RNP Response to RAI B.3.12-3, the integrity of the coating on buried piping was established based on excavation and inspection in the early 1990s. In-situ measurement of coating conductance is not considered prudent due to the potential to cause coating damage during excavation and measurement, the potential for changing the local soil electrolytic conditions, or stressing the coatings due to changes in the local conditions of the supporting soil. Please refer to the RNP Response to B.3.12 for how coatings will be monitored based on inspections.

RNP monitors on a monthly basis rectifier output levels of voltage and amperage for technical comparison of load changes. RNP maintains the cathodic protection system rectifiers by inspecting and via cleaning them to prevent damage. It also directs the conduct of troubleshooting of unexpected changes. Based on site experience, anomalies due to piping configuration changes and other physical damage of installed protection equipment are most often responsible for the changes in output values. Therefore, it is possible to conclude that required changes in rectifier settings are due to damaged equipment and not due to coating degradation. If no physical damage or configuration changes are found, the onset of potentially adverse coating degradation may be occurring. As demonstrated by site experience, a thorough investigation would follow to determine the best of course of action.

Preventive maintenance is performed annually and determines the pipe-to-soil potential at each anode. This procedure is based on the criteria in Regulatory Guide 1.137, Section C.2.h. An independent assessment of this procedure has been performed using NACE RP-01-69 (1992 revision) as a basis for evaluating the cathodic protection system.

RAI B.3.8-5

Please describe the cathodic protection system installed and coating material used on the buried piping.

RNP Response:

The cathodic protection system for was installed to protect the light fuel oil piping and storage tanks from galvanic corrosion. Unit Nos. 1 and 2 each has its own rectifier that incorporates an impressed current system. Each rectifier serves 21 anodes, which induce electron flow to the surrounding structures/piping system. The rectifiers are 240/80 volt AC to DC, air cooled, pad mounted, DC tap changing, with a DC ammeter and voltmeter. The anodes are 1-1/2 inch diameter with a 2 inch diameter enlarged end for lead wire attachment. Each annode is 60 inch long with a type CD Durichlor 51 high silicon chromium cast iron, pre-packaged within an 8 inch diameter by 84 inch long canister, with 10 feet of #8 AWG stranded copper-type HMWPE lead wire. The supply cable from the rectifier to the anodes and the return cable from the piping to the rectifier are #2 AWG stranded copper-type HMWPE. The HMWPE insulation for the lead wire and supply wire is approved for direct burial.

The cathodic protection system supply cable has been installed in a PVC conduit at an approximate depth of 24 inch below grade (i.e., 24 inch below the base of the concrete slab). The PVC is encased in a 4 inch concrete protection barrier from anode to anode. This barrier is for protection against future excavations. A 10 inch diameter concrete anode box with a cast iron traffic-rated lid is utilized at each anode location for access to the anode splices.

The negative terminal of a rectifier is connected to the piping system being protected, and the positive terminal is connected to the strategically located anodes. The locations and installation are in accordance with the recommended practices in Section 8 of the NACE Standard RP-01-69 (1983 revision). Current flow can be adjusted by changing the rectifier output voltage. Current flow to each anode has a maximum current draw of one amp.

The system furnishes protection for piping or vessels in contact with the soil, i.e., the six-inch pipe from the Unit No. 1 area to the DFOST, the bottom of the DFOST, the two-inch piping from the DFOST to the emergency diesel generator day tanks, and the 1-1/2 inch and the 2 inch piping to the auxiliary boilers. Plant personnel monitor and test the system and adjust the rectifier current and voltage, as necessary, to provide adequate protection to the light oil system.

RAI B.3.8-6

In a 1991 NRC inspection, the staff determined that the cathodic protection system was known to have been operating outside of its original specification. The NRC staff concluded that only about 7 years of cathodic protection could be assured following the systems's installation in 1981. The applicant reported that degradation of the cathodic protection system found in 1988 was caused by installation of concrete in the yard. Subsequently, the applicant performed an inspection of emergency diesel generator fuel oil underground piping to close out the staff's concern. The applicant's inspection showed that no galvanic corrosion was evident in the emergency diesel generator fuel oil underground piping. The staff is not clear which buried pipes have degraded coating/pipe and which have no degraded coating/pipe.

A. Please discuss the condition of all buried pipes and their coatings that are covered in this program.

B. Please provide data to show that the cathodic protection system installed on the buried pipes will maintain its integrity and intended function during the extended period of operation.

C. Please discuss what controls are in place to keep the cathodic protection system(s) from being operated outside of their effective lifetime.

RNP Response:

A. The cathodic protection system is designed to protect the buried fuel oil piping, and bottoms of the diesel fuel oil storage tank and the three Unit 1 internal combustion turbine fuel oil tanks, and the Unit No.1 vertical lighting oil tank (not in scope). The underground piping in the scope of this program is identified in the RNP Response to RAI B.3.8-1. Also, as noted in the RNP Response to RAI B.3.12-3, NRC Inspection Report 50-261/91-21 identified finding 91-21-04, Corrosion Protection of Underground Fuel Oil Piping. This finding was closed in 1992 based on inspection results of the EDG fuel oil underground piping on March 27 and May 20, 1992. The piping examination demonstrated the piping coating was intact with no detectable piping degradation.

B. The program described in LRA Section B.3.8 consists of a cathodic protection system, which is a subsystem of the EDGs. This subsystem is completely separate from the EDG and is not in scope of license renewal, and as such, it performs no licensing renewal intended function. However, it is a system intended to protect the buried fuel oil piping from galvanic corrosion. The system is designed and installed in accordance with NACE standards, and is operated, monitored, and maintained by procedure, and has a site history of

making improvements. This provides assurance that it will operate throughout the extended period of operation.

C. Currently, RNP monitors rectifier output levels monthly. The monitoring procedure provides the method necessary to maintain the cathodic protection system rectifiers by inspecting the output voltage and amperage for technical comparison of load changes, and by cleaning to prevent rectifier damage. Another procedure performed annually determines pipe-to-soil potential. This procedure is based on the criteria in Regulatory Guide 1.137, Section C.2.h. An independent assessment of this procedure has been performed using the NACE standard RP-01-69 (1992 revision) as a basis for evaluating the cathodic protection system. Acceptance criteria are consistent with the NACE standard for pipe-to-soil potential measurements.

RAI B.3.8-7

The applicant stated that it completed a hardware upgrade of the cathodic protection system and established base line operating parameters.

A. Please discuss in detail the hardware upgrade and for which piping it applies. Discuss whether the hardware upgrades satisfy the NACE standards.

B. Please describe the base line operating parameters. Discuss whether any of the operating parameters has been examined periodically and compared to the base line to determine the effectiveness of the cathodic protection system.

RNP Response:

A. These hardware upgrades were completed in 1992 and were performed in response to the NRC finding discussed in the RNP Response to RAI B.3.12-4. Additionally, the RNP Response to RAI B.3.8-5 includes a general description of the current system. The upgrades included replacement of 20 anodes, including the addition of one anode and the installation of a new positive cable run in conduit. The buried cable is in PVC conduit encased in a 4 inch concrete barrier for protection. The cable installation is 24 inches below the bottom of the concrete slab. A 10 inch diameter concrete anode box with cast iron traffic rated lid is installed at each anode location. The existing anodes were abandoned in place and replacement locations were selected based on vendor recommendations and specifications.

Work performed on the cathodic protection system was done in accordance with vendor specifications, which were developed in accordance with recommended practices in Section 8 of the NACE Standard RP-01-69 (1983 revision). The system design and performance was assessed in 1996 and 2001 by an independent company. In 2001, the criteria used to determine the system's effectiveness was based on NACE standards RP-01-69 (1992 Revision). The assessment of the annual PM that determines pipe-to-soil potential is discussed in more detail in the RNP Response to RAI B.3.8-4.

B. The Conclusion section in Appendix B, Subsection B.3.8 of the LRA, states that the RNP program with listed enhancements is consistent with the GALL program and identifies any differences as exceptions. The baseline parameters and regular monitoring are described in the RNP Response to RAI B.3.8-4. The NACE standards identified in GALL and the parameters described in GALL provide for periodic monitoring to determine effectiveness.

RAI B.3.8-8

If the leakage in the buried pipes is not detected by inspection via excavation, discuss whether there are other measures that could detect such leak before the leakage challenges the intended function of the system.

RNP Response:

As discussed in the RNP Response to RAI B.3.8-2 (part B), planned enhancements include the performance of pressure testing for leakage. The pressure taps were recently installed during RO-21 in 2002. These enhancements support the confirmation process and can be used to detect leakage in the underground pipe. Currently, leak testing of underground piping from the DFOST to the RAB is performed in accordance with an RNP surveillance procedure, which meets the requirements of the ASME Code, Section XI, Table IWD-2500-1, Item D2.10, and 10 CFR 50.55a(g).

RAI B.3.8-9

The applicant stated that the combined activities in the Buried Piping and Tanks Surveillance Program and Buried Piping and Tanks Inspection Program (in Section B.3.12 of the LRA) will manage aging effects of buried piping and tanks. However, the Buried Piping and Tanks Inspection Program is credited to manage the aging effect of loss of material due to galvanic corrosion whereas the Buried Piping and Tanks Surveillance Program does not. Clarify why galvanic corrosion is not included in the Buried Piping and Tanks Surveillance Program.

RNP Response:

Differences between activities in the Buried Piping and Tanks Surveillance Program and the Buried Piping and Tanks Inspection Program are discussed further in the RNP Response to RAI B.3.12-1.

As noted in the second paragraph of LRA, Appendix B, Subsection B.3.8, galvanic corrosion is not an applicable aging effect for the components included in the Buried Piping and Tanks Surveillance Program. Also, as stated in the first paragraph of LRA, Appendix B, Subsection B.3.8, this program applies only to the fuel oil system. Buried components of the fuel oil system are the same material; therefore, galvanic corrosion is not applicable.

RAI B.3.9-1

The applicant stated that the Above Ground Carbon Steel Tanks Program is credited for aging management of tanks in the fuel oil system. Provide a list of components covered under this program. Discuss whether there are tanks made with materials other than carbon steel that should be considered in the program.

RNP Response:

The components managed under this program include:

Diesel fire pump fuel oil tank
Diesel oil storage tank vent filter
Dedicated shutdown diesel (DSD) fuel oil day tank
DSD fuel oil tank
EDG day tank vent filters
EDG fuel oil day tanks
EDG fuel oil storage tank
EOF DG fuel oil day tank
Unit 1 internal combustion turbine tanks

This program was evaluated specifically for carbon steel fuel oil tanks, and no tanks made of other than carbon steel are included.

RAI B.3.9-2

The applicant described operating experience in which a loss of diesel fuel from the Unit 1 turbine fuel oil tank was detected. The root cause was attributed to pitting corrosion on the inside surface of the tank.

A. Please provide more detail of the Unit 1 turbine fuel oil tank leak event. For example, discuss the root cause of the pitting corrosion inside the tank.

B. If a tank leak was not detected, discuss whether there are other defense-in-depth measures that would detect the leak and alert the operator to take corrective actions before the leakage challenges the intended function of the system. Discuss the consequence and safety significance of a undetected turbine fuel oil leak or leak in other fuel oil tanks covered in this program such as an emergency diesel fuel oil tank leak.

RNP Response:

As discussed in LRA Appendix B.3.9, the leakage from the bottom of the Unit No. 1 lighting oil tank (on LR Drawing G-190204DLR, Sheet 3, it is identified as vertical IC turbine lighting oil tank) was caused from internal corrosion. Consequently this event is associated with the Fuel Oil Chemistry Program, LRA Section B.3.10, which includes periodic cleaning and internal inspection of the fuel oil tanks. An impressed current cathodic protection system is credited with protecting the external surface of tank bottoms (see LRA Section B.3.8). LRA Section B.3.9 describes the Above Ground Carbon Steel Tanks Program, which involves the management of aging affects associated with the external exposed surfaces of the tanks. No other site-specific operating experience relevant to the Above Ground Carbon Steel Tanks Program was identified.

A. During a routine fuel tank inspection on Unit No. 1, several pits were discovered in the Unit No. 1 vertical lighting oil tank floor. Three holes attributed to pitting extended completely through the tank floor. A section of the tank floor was removed to inspect conditions under the tank. The inspection revealed that the tank was positioned directly on the ground and soil conditions under the tank indicated a loss of diesel fuel from the tank. The three Unit No. 1 IC turbine tanks are similar tanks. These tanks are administratively isolated from the Unit No. 1 lighting oil tank. No through wall pitting was identified in the Unit No. 1 IC turbine fuel oil tanks; however, one tank experienced partial pitting of the inside surface of the tank bottom and required repair.

No root cause of the pitting was identified in the evaluation of the event. However, failure to detect the leak was attributed to an inadequate inspection

frequency for the Unit No. 1 tanks. No records of previous inspections were found. Currently, the tanks are scheduled for inspections on a 7-year cycle.

B. The fuel oil tank leak was identified by inspection and was not identified due to a loss of fuel oil inventory. The tank inventory was monitored frequently and no loss of fuel oil occurred that was significant in relation to RNP nuclear safety. Since the leakage did not result in a detectable loss of FO inventory and the Technical Specifications governing FO capacity were not violated, this event is not considered safety significant.

The Unit No. 1 IC turbine tanks and the DFOST have level instrumentation available for monitoring fuel oil inventory. The DFOST and the Unit No. 1 IC turbine fuel oil tanks are independent of each other, and have low level alarms in the RNP control room. Technical Specifications govern the required surveillances that ensure the minimum required inventories are satisfied.

The DSD fuel oil tank and DSD fuel oil day tank have a local low level alarm on their annunciator panel, which would alert operations of low tank level.

The diesel fire pump fuel oil tank level is verified weekly in accordance with surveillance requirements.

The EOF/TSC diesel day fuel oil day tank has a low level alarm on a local annunciator panel that would alert operations to take action to investigate and remedy the condition.

RAI B.3.9-3

The applicant stated that the above ground carbon steel tank program is credited for the exterior surface of the carbon steel tanks. However, If this program covers only the outside surface and not the inside surface of the tank, discuss how the integrity of the inside surface of the tank is assured in light of the turbine fuel oil tank leak which was caused by the corrosion in the inside surface.

RNP Response:

The aging management program applicable to the inside of the fuel oil tanks is the Fuel Oil Chemistry Program. Refer to LRA, Table 3.3-1, Item 7, and Appendix B, Section B.3.10, Fuel Oil Chemistry Program. The bottom of the leaking Unit No. 1 fuel oil tank was repaired with fiberglass laminate.

RAI B.3.9-4

The applicant stated that the Unit 1 turbine fuel oil tank is scheduled for inspections on a five year cycle. GALL XI.M29, "Above Ground Carbon Steel Tanks," recommends system walkdowns during each outage.

A. Please discuss the inspection frequency for all the above ground carbon steel tanks covered in this program in the extended period of operation and provide the technical basis for the inspection frequency.

B. Discuss the inspection procedures in detail.

RNP Response:

The five year inspection interval discussed in LRA Section B.3.9 is referring to an internal inspection and not the walkdown that satisfies the criteria in this program. The internal cleaning and inspection satisfies the criteria of the Fuel Oil Chemistry Program (see LRA Appendix B.3.10). The current interval for internal inspections of the Unit No. 1 fuel oil tanks is 7 years (see the RNP Response to RAI B.3.9-2).

A. The walkdown of the external, exposed surfaces of carbon steel tanks in the scope of this program during the extended period of operation will satisfy the frequency criteria recommended in the "Monitoring and Trending" Element of GALL Program XI.M29.

B. The procedures with enhancements used to perform walkdowns of the external surfaces of the tanks provide qualitative criteria to ensure aging effects are at acceptable levels. The focus of the walkdown is on prevention by ensuring satisfactory condition of the external coatings on the surface of the tanks. For tanks in contact with the ground, the condition of caulking and sealants are observed to prevent water seepage below the tank bottom. If an unsatisfactory condition is identified, it is entered into the Corrective Action Program for evaluation and to determine appropriate corrective actions. The external surfaces of tanks in contact with the ground are also cathodically protected and addressed by the Buried Piping and Tanks Surveillance Program, LRA Section B.3.8. Also, see the RNP Response to RAI B.3.10-10.

RAI B.3.9-5

The applicant stated that this program takes certain exception to GALL XI.M29. The applicant stated that thickness measurements will not be performed on tank bottoms to detect exterior corrosion because the tanks are protected from corrosion by the cathodic protection system and the oily sand that is located underneath of the tanks.

A. Please discuss how would the oily sand prevent corrosion of the tank bottom. Provide operating experience to show the success of the oily sand application. Discuss how the oily sand is situated underneath the tanks. Discuss whether periodic inspections will be performed to ensure the presence of the oily sand because the sand could be dispersed by the force of nature.

B. Please clarify whether the cathodic protection system has been installed in the above ground tanks or will be installed in a future date. If the cathodic system is currently in place, describe its operating experience (e.g., condition of the coating). Describe in detail the cathodic protection system that is installed on the tanks.

RNP Response:

A. The RNP Response to RAI 3.2.1-3 discusses industry practices relating to oily sand. As noted in that response, no credit for the oily sand can be taken to prevent corrosion, protection using oily sand is not needed, since the intrusion of water under the tanks is unlikely and the external surfaces of the tank bottoms are protected by a cathodic protection system. Oily sand was part of the installation of the flat bottom tanks. The tanks are supported on a cylindrical concrete pad that surrounds and contains the sand. The concrete support pads are raised a few inches above the floor of the fuel oil tank containment pads. Along with sealants, this geometry minimizes the chances of seepage of water below the tank. There is no access to the external surface of the tank bottoms, and therefore no periodic inspections are performed. As described in RNP Response to RAI B.3.9-2, a section of a tank bottom was inspected during the repair of a Unit No. 1 fuel oil tank. The presence of water or external corrosion was not identified.

   The AMP description in LRA Section A.3.1.17 has been changed to note that oily sand is no longer credited.

B. Aspects of the RNP Responses to RAIs B.3.9-2, B.3.9-3, and B.3.9-4 relate to the inside surface of the above ground tanks. LRA Section B.3.10, Fuel Oil Chemistry Program, describes the activities that address the aging affects on the inside surfaces of the tank. There is no passive cathodic protection inside

the tanks and there are no current plans to install such protection. The impressed current cathodic protection system is installed and is discussed in LRA Section B.3.8, The Buried Piping and Tanks Surveillance Program. The cathodic protection system is described in the RNP Response to RAI B.3.8-5. The cathodic protection system protects the external surfaces of buried fuel oil piping and the external surfaces of tanks that are in contact with the ground.

RAI B.3.9-6

The applicant stated that the program will be enhanced to assure that external surfaces of the fuel oil tanks are inspected periodically and to include corrective actions. Discuss the documentation process of these enhancements to ensure that the applicant's commitment is properly recorded.

RNP Response:

Refer to LRA UFSAR Supplement, Appendix A, Section A.3.1.17. This section documents the commitments associated with the implementation of identified enhancements.

RAI B.3.10-1

The applicant stated that the Fuel Oil Chemistry Program is credited for aging management of selected components in the fuel oil system in RNP. Please specify each component and system that will be covered by the Fuel Oil Chemistry Program.

RNP Response:

The systems that will be covered by the Fuel Oil Chemistry Program are considered part of the fuel oil system. This system includes the storage of fuel oil and supply piping systems to the EDGs, the Dedicated Shutdown Diesel Generator and the Diesel Fire Pump.

Item 7 in LRA Table 3.3-1 refers to the following equipment:

Diesel fire pump fuel oil tank
DSD fuel oil day tank
DSD fuel oil priming pumps
DSD fuel oil pumps
DSD fuel oil tank
EDG fuel oil day tanks
EDG fuel oil duplex filters
EDG fuel oil hand priming pumps
EDG fuel oil storage tank
EOF DG fuel oil day tank
EOF DG fuel oil pump
EOF/TSC main storage tank
Flow orifices/elements
Fuel oil transfer pumps
Unit 1 IC turbine tanks
Valves, piping, tubing, and fittings

RAI B.3.10-2

The applicant stated that the administrative controls for the Fuel Oil Chemistry Program will be enhanced to improve sampling and de-watering of selected storage tanks. Please discuss the enhancements to improve the sampling and de-watering process. Please specify which storage tanks will be selected and which will not be selected. Discuss the selection criteria.

RNP Response:

The basis for the selection of certain tanks was the review of current practices and activities against the criteria found in the GALL program attributes. The specific enhancements are:

- Periodically take a bottom sample from the underground EOF/TSC main storage tank, and analyze it for corrosion products and bacterial growth.

- Two methods currently exist for sampling fuel oil in DSD FO tank. Only one would result in removing visible water. Consequently, the enhancement is to ensure that a check for visible water is performed and, if found, removed from the bottom of the tank.

- Formalize current practices for bacteria testing for fuel oil. This should include periodically obtaining bottom samples from the Unit 1 IC turbine tanks, DFOST, DSD FO tank, diesel fire pump FO tank and the EOF/TSC main storage tank.

- Ensure that a check for visible water is performed and, if found, removed from the bottom of the diesel fire pump fuel oil tank.

RAI B.3.10-3

The applicant stated that it will formalize existing practices for draining and filling the diesel fuel oil storage tank and bacteria testing for fuel oil samples from various tanks. Please discuss the formalization process. Discuss briefly the procedures of bacteria testing.

RNP Response:

Please refer to the RNP Response to RAI B.3.10-10, with respect to bacteria testing. A Betz Microbiological Test Kit has been used for identifying aggressive bacteria.

A plant procedure currently exists for draining and filling the diesel fuel oil storage tank. Additional formality can be added to this practice by establishing an acceptable frequency of performance.

RAI B.3.10-4

On page B-44 of the LRA, the applicant discussed several events related to degraded fuel oil tank and fuel oil contamination. On page B-45, second paragraph, the applicant stated that no adverse bacteria had been identified and results of chemical testing show bulk average oil conditions have always been within specifications.

A. It seems that the statement on page B-44 contradicts the statement on page B-45. Please clarify which event(s) described on page B-44 occurred in RNP. If there was a case of fuel oil contamination in RNP, clarify whether it was caused by bacteria.

B. Discuss the specifications to which the oil conditions were compared. Discuss the acceptance criteria of fuel oil (This question is related to Question B.3.10-8).

RNP Response:

A. Neither event resulted in a contamination from bacteria.

For the first event, after the FO to the Unit No. 1 failed to light, it was discovered that the Unit No. 1 lighting fuel oil tank contained contaminants that had resulted in filter clogging. These contaminants were attributed to the supplier. This tank is administratively isolated from the IC turbine oil storage tanks.

For the second event, as noted in the application, coating degradation and pitting corrosion were identified on the internal bottom surface of the diesel fuel oil storage tank. The DFOST tank internal inspection performed during Refueling Outage-21 identified that the tank floor had coating failure and some corrosion pitting. The coating on the tank walls, however, was reported to be in good or excellent condition. Corrosion products from the tank were analyzed at the Harris Environmental and Energy Center and concluded that the oil at the bottom contained water with relatively high chlorine concentrations. Carbon steel is susceptible to corrosion when immersed in oxygenated/chlorinated water which may be present under the sediment deposits. The carbon steel is susceptible to pitting corrosion under these deposits. Additional analyses indicated that no aerobic bacteria were present and no fungi/yeast growths were observed in the oil.

Fuel oil normally contains chlorine. Furthermore, an adverse electrochemical potential is established in conjunction with the electrochemical cell formed by pitting corrosion. The electrochemical potential results in exacerbating the

condition by attracting chlorine ions, which tends to concentrate at the corrosion sites. Therefore, this was not a confirmed case of contamination.

The repair to the DFOST tank bottom is discussed in the RNP Response to B.3.10-10.

B. See the RNP Responses to RAIs B.3.10-10 (the introduction and part A) and B.3.10-8.

RAI B.3.10-5

The applicant identified several exceptions to GALL XI.M30, "Fuel Oil Chemistry." One of the exceptions is that the Fuel Oil Chemistry Program in RNP is used to manage aging effects on all system components "wetted" by fuel oil. This results in additional materials in RNP being in scope beyond those in the GALL report. The applicant needs to specify each of the additional materials beyond those in the GALL report.

RNP Response:

Please refer to the RNP Responses RAIs B.3.10-1 and B.3.10-10. Also, refer to LRA Table 2.3-25 for the Component/Commodities in the fuel oil system that require an AMR.

RAI B.3.10-6

On page B-45 of the LRA, the applicant is taking exception to the one-time inspection. GALL VII.H1, "Diesel Fuel Oil System," specifies that for the internal surface of a carbon steel tank the Fuel Oil Chemistry Program be augmented by a one time inspection in accordance with GALL XI.M32, "One-Time Inspection." The applicant stated that a one-time inspection of small, elevated, diesel fire pump fuel oil tank and diesel generator day tanks is not warranted because the small tanks provide limited access to the tank internals making it impractical to clean and perform a meaningful inspection. The applicant stated that ultrasonic testing is considered inappropriate to detect small amounts of pitting in tanks constructed of carbon steel that is measured in units of gauge thickness. The applicant also stated that on the basis of operating history, external tank and structure inspections are considered sufficient to identify degradation in the tank walls.

A. Please discuss how can the internal surface integrity of the diesel fire pump fuel oil tank and diesel generator day tanks be validated if a one-time inspection will not be performed on these tanks.

B. Please discuss degradation history of all fuel oil tanks that are covered under this program.

C. Please discuss how the external inspection of the fuel oil tanks can assure the integrity of the inner surface of the tanks.

D. Please describe the external tank and structural inspection procedures that the applicant will perform and the frequency of such inspections.

E. If ultrasonic testing is inappropriate to detect degradation in fuel oil tanks, the applicant needs to propose other nondestructive examinations to inspect the inner surface of the tanks.

RNP Response:

A. There is no history of failures of the diesel fire pump fuel oil tank and diesel generator day tanks. The diesel generator day tanks are sheltered inside the RAB and not prone to condensation. Fuel oil supplied to the day tanks is taken from a level well above the bottom of the diesel fuel oil storage tank. Water is periodically checked and removed from the emergency diesel day tanks, if found. Consequently, there is no reason to suspect that the integrity of these day tanks is in question.

The diesel fire pump fuel oil tank receives periodic shipments of fuel oil from a local supplier. It is situated outdoors. Currently, fuel oil is sampled periodically,

but not from the bottom drain and there is no periodic requirement for checking for and removing water from the bottom drain. Therefore, a one-time ultrasonic test or other non-destructive test (or inspection) of the internal surface of the diesel fire pump fuel oil tank will be performed in locations most susceptible to corrosion. Testing will be accomplished prior to the beginning of the period of extended operation. If degradation is found, further actions will be evaluated under the Corrective Action Program. The inspection of the diesel fire pump fuel oil tank will be performed under the One-Time Inspection Program.

As a result of the above response, the information in LRA Subsection A.3.1.31, One-Time Inspection Program, is modified to include a one-time ultrasonic, or other non-destructive test, of the diesel fire pump fuel oil tank in locations most susceptible to corrosion.

B. Site operating experience over a recent 10-year period was reviewed and summarized in LRA Section B.3.10. No failures were identified.

C. An external inspection would not be expected to detect minor degradation on the inner surface of the tanks. However, it will identify minor leakage, which will precede the amount of degradation that would challenge the structural integrity of the tank.

D. Formal inspections (see LRA Sections B.3.9, B.3.15 and B.3.17) will involve a walkdown of the tanks and the area surrounding the tanks. In addition to formal inspections, plant operators on rounds and chemistry personnel obtaining samples are able to identify such leakage. Such leakage would be identified and reported in the Corrective Action Program.

E. Ultrasonic testing or other non-destructive testing will be performed as noted above.

RAI B.3.10-7

Page B-45 of the LRA, the applicant is taking exception to Detection of Aging Effects in GALL XI.M30. The applicant stated that ultrasonic thickness measurements of bottoms of large storage tanks are not typically performed at RNP unless warranted by the level of coating degradation and corrosion found during inspection. Please demonstrate how the thickness of the tank bottom will be verified without ultrasonic measurements. Discuss the procedures in order to verify the thickness of the tank bottom.

RNP Response:

See the RNP Response to RAI B.3.10-10 (part A, paragraph entitled "Detection of Aging Effects").

RAI B.3.10-8

Page B-45 of the LRA, the applicant is taking exception to fuel oil standards in GALL XI.M30. The applicant will use alternate standards and acceptance criteria for fuel oil sampling in place of ASTM standards D 1794, D 2709, D 4057, and modified D 2276, which are recommended in the GALL report. The applicant needs to demonstrate that its alternate standards and acceptance criteria are consistent with the ASTM standards.

RNP Response:

Please note that the GALL report recommends ASTM D 1796 and not ASTM Standard D 1794. At RNP, testing is based on ASTM D 1796-97, "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method," in lieu of ASTM D 2709 for determining water and sediment using a centrifuge approach. ASTM D 1796-97 is considered a more appropriate test for the fuel oil used at RNP. For additional information regarding the other exceptions, please refer to the RNP Response to RAI B.3.10-10 (part A).

RAI B.3.10-9

Page B-45 of the LRA, the applicant is taking exception to fuel oil additives in GALL XI.M30. The applicant stated that based on operating history and fuel oil management activities, biocides, biological stabilizers and corrosion inhibitors are not necessary and are not used in the fuel oil at RNP. GALL XI.M30 states that the quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. On page B-44, the applicant has suggested that there has been cases of degraded oil events occurring in RNP. Please clarify how would the quality of fuel oil in RNP be maintained without these additives

RNP Response:

Please refer to the RNP Response to RAI B.3.10-10. There is no evidence to suggest that additives would have precluded these events. Regarding the Unit No. 1 vertical lighting oil tank, it is important to note that filter clogging was caused by debris from a delivery truck and not caused by fuel oil sediments or biological growth. The other event is related to pitting on the bottom of the DFOST tank and the origin of the aggressive environment for this occurrence was not definitively established. However, the primary corrosion preventive is the tanks internal coating. The degraded internal coating on the bottom of the tank has since been replaced with an improved coating material.

A review of Condition Reports over a recent 10 year period was performed. No events due to degraded fuel oil were identified. Considering that additives such as biocides and stabilizers have not been used at RNP and that there is no adverse site operating experience due to degraded fuel oil based on storage methods, the current methods are considered prudent and acceptable. Therefore, no fuel oil additives are considered necessary.

RAI B.3.10-10

In its conclusion, the applicant stated that its Fuel Oil Chemistry Program is consistent with GALL XI.M30. However, the applicant did not provide sufficient information on the Fuel Oil Chemistry Program to support its conclusion. In addition, the applicant is taking major and significant exceptions to GALL XI.M30. To demonstrate that its Fuel Oil Chemistry Program is consistent with the GALL report, the applicant needs to do the following:

A. The applicant needs to resolve the staff's concerns regarding the exceptions to GALL XI.M30 by providing a technical basis for each exception.

B. The applicant needs to demonstrate that its current Fuel Oil Chemistry Program is within the current licensing basis.

RNP Response:

The level of information presented in the LRA was based on guidance summarized in a letter from Pao-Tsin Kuo (NRC) to Alan Nelson (NEI) entitled: "Observations from the Nuclear Energy Institute (NEI) License Renewal Demonstration Project and Comments from an Advisory Committee on Reactor Safeguards (ACRS) Letter that May Result in Changes to NEI 95-10, Revision 3," dated July 24, 2002. Item 3 and 13 of the attachment to that letter state:

"3. When the Generic Aging Lessons Learned (GALL) report identifies specific conditions that should be met for the GALL report's conclusion to apply, the applicant should provide a statement in the license renewal application indicating that the conditions specified in the GALL report are met. The appropriate wording to indicate that an applicant's aging management program meets the evaluation as described in the GALL report is "AMP is consistent with GALL." Engineering judgment may be used by the applicants in making this determination. When there is some expectation that NRC staff may not come to the same determination with respect to a particular program element, the applicants should identify these as differences from GALL report in their license renewal application."

"13. The Plant X sample application presents summary information and does not include detailed information that is in the GALL report. The regional inspectors perform inspection/verification to confirm the accuracy of information in the application. On-site documentation should be clearly linked to summary application details to facilitate the regional inspection. Applicants need a clear paper trail that is auditable and retrievable for onsite inspections."

As noted in LRA Section B.3.10, these differences have been evaluated and determined to result in no significant adverse effects on the ability of the program to manage aging effects. Additionally, the LRA states: "The Fuel Oil Chemistry Program, with the enhancements identified previously, is consistent with GALL Section XI.M30, Fuel Oil Chemistry, with acceptable exceptions, and implementation of the Program provides reasonable assurance that the aging effects will be managed..." Therefore, the exceptions are acceptable based on engineering judgment, and after the referenced enhancements are made, the program will be consistent with GALL.

A. In the LRA program description for B.3.10, exceptions were taken to the program elements in GALL relating to: Scope of Program, Preventive Actions, Parameters Monitored/Inspected, and Detection of Aging Effects. (Note that the last bullet in the Conclusion section should be under "Detection of Aging Effects" and not "Preventive Actions.")

   Scope of Program: RNP expanded the scope of the program to manage potential aging effects in more components than the large storage tanks. The focus in the GALL Report is placed on large storage tanks, thereby maintaining the fuel oil quality and its associated container. The internal environments of the components in the fuel oil system are exposed to the quality of fuel oil controlled under this program. Fuel oil from the main storage tanks is drawn from a level above the bottom and is representative of the bulk average fluid conditions. Consequently, the components downstream are being managed by the efforts taken to maintain the quality of fuel oil.

   Monthly surveillance testing requires a check for water in the EDG day tanks. To prevent biological growth, the surveillance requires that water be removed, if found. Quarterly fuel oil samples are taken from the EDG day tanks and are tested for water and sediment. The results indicate that fuel oil has remained within specifications for water and sediment.

   Preventive Actions: As noted in the LRA based on operating history and fuel oil management activities, biocides, biological stabilizers, and corrosion inhibitors are not necessary and are not used in the fuel oil at RNP. RNP shares fuel oil with Unit No. 1, which runs an internal combustion (IC) turbine that uses significantly more fuel than the Unit No. 2 EDGs. This usage results in maintaining a relatively fresh supply of fuel oil. The Unit No. 1 tanks are used as a repository for fuel oil when the Unit No. 2 diesel fuel oil storage tanks are drained for periodic inspections and cleaning, as well as periodically refreshing the supply between inspections. This tends to maintain a relatively fresh supply of fuel oil immediately available to the EDGs. The dedicated shutdown diesel generator (DSD) fuel oil storage also receives its fuel oil from

Unit No. 1. To date, site operating experience supports the viability of this process.

Parameters Monitored/Inspected, Detection of Aging Effects and Acceptance Criteria: Alternate standards and acceptance criteria are used for fuel oil sampling at RNP in place of the ASTM standards recommended in the GALL Report. The standards being used at RNP meet or exceed those recommended in GALL. For example, ASTM Standard D 4057 recommended in GALL addresses industry practices for sampling techniques in large fuel oil storage tanks in the petroleum industry. These tanks are significantly larger than the tanks at RNP. NRC Inspection Report 91-21 questioned the methodology used in sampling the DFOST at RNP. The method used at RNP of recirculating the oil within the tank was shown to be equivalent to the industry standard to which RNP is committed (ASTM D 270-1975). The NRC was satisfied with the testing results, showing that the samples drawn using both methods yielded "virtually identical results. ... This testing provided justification for the licensee to obtain fuel oil storage tank samples by their existing methodology." ASTM D 2276 covers the test method for determination of particulate contaminants in aviation turbine fuel using a field monitor. Fuel oil is periodically sampled for suspended particulate using a procedure, which is an equivalent laboratory test. The test method is based on ASTM D 5452, which covers the gravimetric determination by filtration of particulate contaminant in a sample of aviation turbine fuel delivered to a laboratory. This test provides equivalent results using a filter with pore size of 0.8 μm. This pore size (0.8 μm) is identified as the modified test method in GALL for the field test. Equivalency is established because the same filter size is being used as in the suggested modification to the field test method. Additionally, even though the test apparatus is different, its location is in a controlled laboratory environment. It would not be practical to use the laboratory test setup in the field location.

Detection of Aging Effects: Ultrasonic thickness (UT) measurements of bottoms on large storage tanks are not typically performed at RNP unless warranted by the level of coating degradation and corrosion found during inspection. The Fuel Oil Chemistry Program addresses management of the internal surfaces of the components within the fuel oil system. The response to this RAI is based on addressing Loss of Material due to corrosion mechanisms from inside the tank. The Above Ground Carbon Steel Tanks Program and the Buried Piping and Tanks Surveillance Program address the external surfaces of these carbon steel tanks.

Internal inspection of the DFOST is performed periodically based on a maximum 10 year interval. The inspection intervals stated in LRA Sections B.3.9 and B.3.10 for the Unit No. 1 tanks should have said internal inspections of the Unit No. 1 IC turbine tanks are performed periodically and meet the recommendations in API 653. Internal surfaces are inspected for

coating integrity. If coating integrity were compromised, additional inspections and appropriate testing would be performed to determine the extent of damage. However, if coatings are intact, then corrosion is not anticipated and further testing would not be necessary.

In recent years, two of the Unit No. 1 IC turbine tanks and the DFOST tank experienced degradation due to pitting. At that time UT testing was done to establish the bottom condition. These tanks have since been repaired. The most recent tank repair was for the DFOST tank, which was repaired in fall 2002 during Refueling Outage-21. After the tank was drained, oil sludge was removed and the interior of the tank was pressure washed with high temperature water and citrus degreaser. The bottom of the tank was also sponge jet blasted. Ultrasonic testing measurements were taken at several locations, which established the condition of the tank bottom. No weld repairs of the pitting were required or performed. Belzona Ceramic-R-Metal compound was applied to the tank bottom and on the walls a few inches above the bottom. Provided this coating is shown to remain intact during subsequent tank inspections, corrosion is not anticipated and no further ultrasonic testing would be necessary.

The 10 year inspection interval for the DFOST has proven to be adequate for identifying aging effects before damage occurs.

Detection of Aging Effects: A one-time ultrasonic test or other non-destructive test of the internal surface of the diesel fire pump fuel oil tank will be performed in locations most susceptible to corrosion. For additional information in this regard, please refer to the RNP Response to RAI B.3.10-6.

Leakage from elevated tanks is readily observable. Through-wall leakage would be detected during operator rounds by external visual inspection of the tank, foundation, and dikes.

B. In accordance with UFSAR Section 1.8.0 (page 1.8.0-19) and Technical Specifications 3.8.3, fuel oil is sampled for API or specific gravity, water and sediment, viscosity, and cloud point. These specifications are identified in the Technical Specifications bases. New fuel received for storage in the Unit No. 1 IC turbine fuel oil storage tanks and subsequently transferred to the Unit No. 2 DFOST is verified to meet the analysis limits prior to adding to the Unit No. 1. Stored fuel in the Unit No. 1 IC turbine tanks and Unit No. 2 DFOST is sampled every 31 days. Accumulated water is checked for and removed from each fuel oil storage tank every 31 days.

The enhancements that will be made to support operation during the extended period go beyond the CLB at RNP. One example of such an enhancement is the test for bacteria in the DFOST. This test is not a licensing requirement at RNP, but it is good practice. The laboratory uses a

standard kit to periodically perform this test, and testing is done to the manufacturer's instructions. Formalizing bacteria testing means to convert these manufacturer's instructions into formal laboratory procedures. For further information on enhancements associated with dewatering tanks, please refer to the RNP Response to B.3.10-2.

RAI B.3.11-1

The required withdrawal schedule criteria of ASTM Standard E185-82 are based on estimated fluence exposures, in effective full power years (EFPY) for the inner surface (ID) and 1/4T locations of the H. B. Robinson Nuclear Plant (RNP) reactor vessel (RV). For PTS, the RNP RV is limited by upper circumferential weld 10-273 (Heat W5214), which is represented in the RNP RV surveillance program. Since this material has a projected RT_{PTS} shift above 200°F, the applicant is required by 10 CFR Part 50, Appendix G, and ASTM Standard E185-182 to withdraw five RV surveillance capsules in accordance with the requirements of the standard.

In addition, Section 5.3.1 of the RNP UFSAR provides a detailed description of the RNP RV surveillance program. The UFSAR indicates that the applicant has already pulled and tested Capsules S, V, Z, and T in accordance with the requirements of the ASTM standard. However, Footnote 4 of the UFSAR Section 5.3.1 description implies that Capsule V will be reinserted within the RNP RV cavity either before or during the license extension period. In order to confirm consistency with the Evaluation and Technical Basis section of GALL Program XI.M31, "Reactor Vessel Surveillance Program," clarify how the withdrawal schedule for remaining Capsules X, U, V, and W equate to estimated exposures (in terms EFPY relative to the end of extended operating period for RNP) for the inner surface and 1/4T locations of the RNP RV during and through the extended period of operation for RNP, which these capsules are required to be withdrawn and tested in accordance with ASTM E185-82, and which of these capsules are considered by the applicant to be additional optional capsules for withdrawal and testing. In addition Please clarify whether Capsule V or other capsules will be reinserted into the RV cavity, and if required for withdrawal during the period of extended operation, how the time and position of reinsertion will ensure that the exposures of these capsules will meet the intent of ASTM E185-82 for the extended period of operation.

RNP Response:

Capsules S, V, and T have been removed and evaluated as required by the RNP RV Surveillance Program, and the results have previously been reported. The results are documented in the NRC's Reactor Vessel Integrity Database (RVID), Version 2 [with noted comments to RVID, Version 2, provided by letter from R. Warden (CP&L) to NRC, Serial RNP-RA/99-0162: "Comments on Reactor Vessel Integrity Database Data," dated August 27, 1999.]. Note that a recent UFSAR change has been made to correct errors relating to capsule references and descriptions. Capsule Z was inadvertently removed from the reactor vessel and capsule Y was inadvertently referred to as capsule V in the UFSAR.

Capsule X was removed from the reactor vessel during RO-20 in Spring 2001, and the test results are reported in WCAP-15805, "Analysis of Capsule X from Carolina Power and Light Co." This report was submitted by RNP letter from B. L. Fletcher III (CP&L) to the NRC, Serial RNP-RA/02-0033: "Report of the Analysis of Surveillance Capsule X for the Reactor Vessel Radiation Surveillance Program," dated April 25, 2002.

Capsule X was removed at 20.39 EFPY, with a fluence value of 4.49 x 10^{19} n/cm^2, E> 1.0 MeV. Post-irradiation mechanical tests of the Charpy V-notch and tensile specimens were performed, along with a fluence evaluation. The beltline material test results are compared with the predicted values from Regulatory Guide 1.99, Rev. 2, in WCAP-15805, which includes calculated fluence values at 29 EFPY and 50 EFPY for beltline materials, including inlet and outlet nozzles and welds.

The surveillance capsule removal schedule is included in WCAP-15805 and is provided in Appendix A, Section A.2.1.2, of the LRA. Capsule U will be the fifth capsule removed, which is recommended to occur at approximately 29.8 EFPY exposure (at approximately calendar year 40), with a peak fluence value of 6.00 x 10^{19} n/cm^2, E> 1.0 MeV. This corresponds with the 50 EFPY fluence value projected for the RPV clad/base metal interface at the end of the 60 calendar years (per WCAP 15805, Table 6-14). Therefore, Capsule U should provide data representative of the vessel materials at the end of the license renewal period and should demonstrate compliance with 10 CFR Part 50, Appendix G, and ASTM Standard E185-82.

As noted in WCAP-15805, Table 7-1, Capsules Y and W currently lag the vessel peak fluence. Based on the current RNP surveillance plan, as specified in Section 5.3 of the LRA UFSAR Supplement, these two capsules will be repositioned at the end of the current license into lead positions, such that they may be removed for testing during the period of extended operation, if needed. Capsule Y is expected to surpass a fluence value 6.00 x 10^{19} n/cm^2 at approximately 50 calendar years, and would be available for removal later in the period to obtain relevant fluence data. Capsule W has lower exposure than Capsule Y, and would be available for use beyond the period of extended operation, if needed. Therefore, since additional capsules are available to provide the necessary data during and beyond the period of extended operation, consistent with the recommended RV surveillance capsule withdrawal and testing program outlined in GALL Program XI.M31, the program is considered consistent with GALL.

RAI B.3.11-2

In regard to the USFAR supplement summary for the RV Surveillance Program, please clarify that the RV Surveillance Program will be implemented in accordance with the appropriate requirements of 10 CFR Part 50, Appendix H for RV materials surveillance programs (not the NRC's recommend guidelines of RG 1.99, Revision 2), and that the data obtained through fracture toughness testing will be used in the applicant's calculations of the time-limited aging analysis calculations of: (1) the RNP pressure-temperature (P-T) limits and low temperature overpressure protection (LTOP) limit setpoints, as required by Section IV.A.2 of 10 CFR Part 50, Appendix G; (2) the USE values/EMA analyses for the RNP RV beltline materials, as required by Section IV.A.1 of 10 CFR Part 50, Appendix G; and (3) the RTPTS values for the RV beltline materials, as required by 10 CFR 50.61 for PTS evaluations. In addition, please amend the UFSAR supplement description for the RNP RV Surveillance Program to reflect the clarifying information in the applicant's response to RAI B.3.11-1 and that collectively, that this additional UFSAR Supplement information ensures that the RNP RV Surveillance Program when implemented is consistent with the program attributes of GALL Program XI.M31, "Reactor Vessel Surveillance Program."

RNP Response:

The CP&L response to GL 92-01, Revision 1, described how the RNP Reactor Vessel (RV) Surveillance Program met the intent of 10 CFR 50, Appendix H (reference letter from R. Starkey, Jr. (CP&L) to NRC, Serial: NLS-92-179: "Response to GL 92-01, Revision 1, Reactor Vessel Structural Integrity," dated July 6, 1992). The RV Surveillance Program will be implemented in the same manner during the period of extended operation.

Appendix A, Section 3.1.19, of the LRA, Reactor Vessel Surveillance Program, will be revised to refer to 10 CFR 50, Appendix H, instead of Regulatory Guide (RG) 1.99, Rev. 2. The information in the first paragraph of LRA Subsection A.3.1.19, Reactor Vessel Surveillance Program, is modified to read:

> "Periodic testing of metallurgical surveillance samples is used to monitor the progress of neutron embrittlement of the reactor pressure vessel as a function of neutron fluence, in accordance with 10 CFR 50, Appendix H."

The data obtained through surveillance testing will be used in the determination of:

1) RNP P-T and LTOP limits, as required by Section IV.A.2 of 10 CFR 50, Appendix G (refer to the RNP Response to RAI 4.2.2.3-1 for additional details).
2) USE values, as required by Section IV.A.1 of 10 CFR 50, Appendix G (refer to the RNP Response to RAI 4.2.2-1 for additional details),
3) RT_{PTS} values, as required by 10 CFR 50.61, for PTS evaluations (refer to the RNP Response to RAI 4.2.1-1 for additional details).

Please refer to the RNP Response to RAI B.3.11-1 for changes to be made to the UFSAR Supplement for the RNP RV Surveillance Program.

RAI B.3.12-1

The applicant stated that it will combine this program and the Buried Piping and Tanks Surveillance Program as discussed in Section B.3.8 of the LRA to manage aging effects associated with the buried piping and tanks. The staff has the following questions:

A. As was discussed in Section B.3.8, please confirm that there are no buried tanks covered under this program.

B. Please provide a list of all buried pipes that are covered under this program.

C. This program covers buried cast iron piping and fittings which the surveillance program in Section B.3.8 does not cover. Discuss why Section B.3.8 of the LRA does not cover buried cast iron piping and fittings.

RNP Response:

RNP does not intend that the referenced be combined. The Buried Piping and Tanks Inspection Program (described in LRA B.3.12) manages aging by relying on the integrity of the coatings to prevent corrosion, and involves buried components within the scope of license renewal. The Buried Piping and Tanks Surveillance Program (described in LRA B.3.8) manages aging by using an impressed current cathodic protection system, and the fuel oil system is the only piping system at RNP that has such a system. The aspects relating to coating inspections in B.3.8 rely on the activities described under the program in B.3.12.

A. The programs names used in the LRA are based on those presented in GALL. As noted in the Conclusions section under the listed exception for the Scope of Program (LRA B.3.12), "The Program contains no buried tanks."

B. Please refer to the RNP Response to RAI B.3.10-10.

C. The scope of the program in B.3.8 (refer to the RNP Response to RAI B.3.8-1) is small when compared with the scope of the program discussed in B.3.12, and program B.3.8 only contains components in the fuel oil system. The buried fuel oil piping is not cast iron.

RAI B.3.12-2

The applicant stated that leaks have occurred in the north service water header pipe in July 1995, and in March and September 1998.

A. The applicant stated that other buried pipes on site have not exhibited exterior corrosion such as experienced on the north service water header. Discuss how the exterior condition of other buried pipes could be assured unless an inspection via excavation of each buried pipe has been performed. Please discuss whether all the buried pipes have been inspected via excavation.

B. Please discuss how leaks in the north service water header were detected.

C. The applicant implied that because leaks had been detected in the north service water header pipe; therefore, leaks can be detected in the buried fuel oil pipe(s). Discuss how leaks can be detected in the buried fuel oil system piping without excavation.

RNP Response:

A. See LRA Table 3.3-1, Item 17. The corrosion on the north service water header resulted from holidays caused during installation, and leakage was detected by standing surface water appearing above the pipe. There have been no similar site experiences with other buried piping in the service water or fire protection systems.

Excavation and Inspection of buried pipe is not required by the GALL program. It requires inspection when buried pipe is excavated for any reason. As stated in LRA B.3.12, RNP is consistent with the approved GALL program. If during inspections, there is an indication that coating is degraded, then the appropriate corrective actions will be determined under the Corrective Action Program, which will address aspects such as the degraded condition and additional inspection requirements.

The exterior inspection of the SWS piping involved only the affected portion of the north service water header. When the Radwaste Building was erected, the north service water header had to be rerouted. Three leaks have occurred in the north service water header in the section of pipe that was installed in 1984. The leaks were identified in July 1995, and in March and September 1998. The root cause of the March and September 1998 leaks is improper installation of the tapecoat external wrapping. The root cause of the July 1995 leak was misoperation of a backhoe during initial installation.

Subsequently, this portion of the service water piping was raised above ground level.

B. The information requested is contained in the response to part A above.

C. Comparisons of fuel oil system flow totalizers located at each end of the buried piping from Unit No. 1 to the fuel oil storage location at Unit No. 2 can be used to monitor for a loss of fuel oil. Additionally, pressure testing of buried pipe assists in identifying underground leaks in the fuel oil system. RNP monitors for underground fuel oil leakage to assure compliance with environmental permits and regulations. Minor leakage is expected to have essentially no impact on the system intended function. Regarding excavation of buried piping for the sole purpose of inspection, RNP recognizes the potential for damaging or stressing coatings on buried piping and the affect it has on changing the electrochemical nature of the soil.

The RNP Response to RAI B.3.12-1 clarifies that the Inspection program in B.3.12 is not combined with the Surveillance program B.3.8. The statements regarding leakage in B.3.12 only refer to the scope of water systems included in the inspection program and make no inferences regarding fuel oil piping. Leak detection in fuel oil piping is discussed in the surveillance program, B.3.8. The RNP Response to RAI B.3.8-2 (part B) discusses the pressure testing used to monitor for leakage in the buried fuel oil piping.

RAI B.3.12-3

The applicant stated that periodic excavations of buried piping for inspection are not warranted.

A. If periodic excavations of buried piping are not warranted, please discuss the frequency of excavating inspection for each of the buried pipes covered under this program.

B. Please discuss the inspection history and results of all buried pipes covered under this program. If a buried pipe covered under this program has never been inspected since the commercial operation of the plant, demonstrate that each buried pipe is within its design specifications and its structural integrity is acceptable prior to the extended period of operation and during the extended period of operation.

RNP Response:

A. The period of inspection for buried piping will depend primarily on maintenance and modification activities. There are no schedule frequencies for excavations. If during maintenance, degraded pipe coatings are identified, then an appropriate sample would be determined based on engineering judgment and other relevant operating experience. LRA Section B.3.12 provides summary-level operating experience regarding leakage in buried pipe due to corrosion from the external environment.

B. RNP reviewed the activities described in GALL Section XI.M34. The criteria implied in this RAI question are not the same as those listed in GALL.

Under program element "Detection of Aging Effects" the GALL program element states:

> "...Buried piping and tanks are inspected when they are excavated during maintenance. The inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. However, because the inspection frequency is plant specific and also depends on the plant operating experience, the applicant's proposed inspection frequency is to be further evaluated for the extended period of operation."

A summary-level discussion has been provided in the LRA regarding operating experience. As noted in LRA Section B.3.12, the site operating experience and the high soil resistance are the basis for not performing scheduled inspections. Additionally, service water systems can tolerate some leakage and still achieve its safety function. A jockey pump normally

maintains the site fire protection system headers at normal operating pressure. The inability of the jockey pump to maintain header pressure would provide notice of potential leakage in buried piping. Monthly checks of the Dedicated Shutdown Diesel (DSD) jacket water system expansion tank would reveal loss of jacket water system integrity and provide a means to detect leakage in DSD buried piping.

Please refer to the RNP Response to RAI B.3.8-1 for piping components covered by the cathodic protection system.

NRC Inspection Report 50-261/91-21 identified finding 91-21-04, Corrosion Protection of Underground Fuel Oil Piping. This finding was closed in 1992 and the closure notes are provided below:

"Actions taken and closure was based on inspection results of the EDG fuel oil underground piping on March 27 and May 20, 1992. The piping examination demonstrated the piping coating was intact with no detectable piping degradation. The licensee (CP&L) concluded from this sample that the underground fuel oil piping had not degraded by galvanic corrosion. Additionally, the licensee completed a hardware upgrade of the cathodic protection system and was establishing base line operating parameters. The NRC found that the technical staff demonstrated a good knowledge level of the system operation and design. The inspector concluded the licensee had accomplished appropriate actions to verify the integrity of the underground fuel oil piping and had upgraded the cathodic protection system to an operable status."

RAI B.3.12-4

In Section B.3.8 of the LRA, the applicant stated that in an NRC inspection of a degraded cathodic protection system of a buried pipe, the NRC concluded that about 7 years of cathodic protection could be assured following the system's installation since 1981 and that the cathodic protection system on that buried pipe had been operated outside of its original specification. In Section B.3.12, the applicant stated that the leak occurred in the north service water header pipe was caused by the improper installation of the coating material. In light of these two observations,

A. Please discuss whether the cathodic protection system is installed properly on all buried pipes.

B. Please discuss the potential of service-induced coating degradation after a period of operation even if the coatings were properly installed on all buried pipes.

C. Please discuss whether all buried pipes, regardless of materials of construction, are installed with the cathodic protection system.

D. Please provide the year in which the cathodic protection system was installed in all buried pipes.

E. Based on a period of 7 years for the effectiveness of the cathodic protection system, discuss the need of periodic inspections of buried pipes to confirm the effectiveness of the cathodic protection system and integrity of the pipes unless the applicant can propose an alternative inspection to assure the effectiveness of the cathodic protection system and the structural integrity of buried pipes.

RNP Response:

Please refer to the RNP Response to RAI B.3.12-3.

With respect to the cathodic protection system, installation was completed in 1981.

RAI B.3.12-5

The applicant stated that if coating failures do occur, there will be ample time to identify and repair leaks before catastrophic failure.

A. Please discuss how much time is allowed for the operator to identify the buried pipe leak and take corrective actions before the leak in any of the buried pipe would challenge the intended function of the system.

B. Please discuss the potential for the operator to safely shutdown the plant, given a leak has occurred in a buried pipe.

C. Please discuss the consequence and safety significance of a catastrophic pipe failure in each of the buried pipes.

RNP Response:

A. The conclusion that there will be ample time to identify and repair leaks before catastrophic failure was based on operating experience with leakage in the SWS.

As noted in LRA Section B.3.12, the failures experienced to date were due to localized failures of the external coating of buried pipes. The bare spot or pipe material exposed by the defect in the coating becomes the anode, and the large intact coating area becomes the cathode. The local spot is preferentially attacked, resulting in a through-wall defect. Due to the concentrating effects of galvanic corrosion, the damage is very localized, and the adjacent piping with intact coatings is usually not damaged at all, which is the reason that the overall pipe retains its structural integrity. The leakage becomes detectable long before the localized openings can expand to the extent to weaken the pipe structurally.

Catastrophic failure of piping has been associated with cracking. Loss of material, not cracking, is the aging affect associated with this program. Catastrophic failure due to loss of material would require corrosion over large portions of the piping causing a loss of overall structural integrity. The GALL program prescribes the use of inspection when maintenance is performed as a means of detecting degradation of pipe coating, which could lead to unacceptable amounts of loss of material. The acceptance of this approach is dependent on site history. RNP's site history shows that the soil has high resistivity and is not especially harsh. This has lead to very few buried pipe failures. As noted above, localized damage would most likely be identified by indications of leakage or a loss of pressure in the system. On this basis, the inspection program is well suited to prevent catastrophic failure and loss of overall structural integrity.

B. The aging management for this buried piping will have a high likelihood of preventing such catastrophic failure. Additionally, it should be noted that exterior coating is "non-Q" even though the pipe itself is "Q". This is standard industry practice that reflects the fact that the pipe does not lose its safety function if the exterior coating fails. Based on the above, expected leakage resulting from coating failures will be small and will not affect the ability of operations personnel to safely shutdown the plant.

C. Plant abnormal and emergency operating procedures provide instructions for mitigating a catastrophic failure of the SW system. However, such failures are considered extremely unlikely given the plant operating history and the proposed aging management program.

RAI B.3.12-6

The applicant stated that the program will be enhanced by adding certain requirements. Please discuss the documentation process of these enhancements to assure that the applicant's commitments will be properly implemented during the extended period of operation and that the documentation will be available for future NRC inspection.

RNP Response:

Refer to LRA UFSAR Supplement, Appendix A, Subsection A.3.1.20, which documents the commitment regarding implementation of these enhancements.

RAI B.3.12-7

The objective of the Buried Piping and Tanks Inspection Program is to prevent, monitor, and mitigate exterior corrosion of the buried piping and tanks. However, the program does not address the integrity of the inside surface of the buried pipes. The staff understands that Section B.3.10, Fuel Oil Chemistry Program, manages the aging effects on the inside surface of the buried fuel oil pipes; however, the Fuel Oil Chemistry Program does not specify the inspection of the inside surface of the buried fuel oil pipes.

A. Please discuss whether the Buried Piping and Tanks Inspection Program covers the inspection of the inside surface of the buried pipes. If not, discuss whether there is an inspection program to ensure the integrity of the inside surface of the buried pipes.

B. Please discuss the potential of corrosion occurring on the inside surface of the buried pipes.

RNP Response:

A. Section B.3.12 does not cover inspection of the inside surfaces of buried pipe, and no such inspection program is proposed for aging management of buried fuel oil piping.

B. The Fuel Oil Chemistry Program manages the aging mechanisms associated with the inside surfaces of fuel oil piping and components. With respect to internal surfaces, buried piping is subjected to conditions that are substantially similar to above ground piping. The Fuel Oil Chemistry Program ensures the quality of the fuel oil by periodic sampling of fuel oil, by removing water from the bottom of the tank if any is found, and checks for aggressive bacteria. The program also credits periodic cleaning and inspections of large storage tanks. Prior to entering the buried pipe, fuel oil is drawn from the storage tanks well above the tank bottom. The fuel oil velocities in the tank are insufficient to entrain water into the supply piping; therefore, water would not be present in the piping system components. During the search of site operating experience, no leakage or deleterious condition was identified due to aging mechanisms associated with internal surfaces of carbon steel fuel oil pipes, fittings, and valves.

RAI B.3.13-1

In addressing the program element *Confirmation Process*, the applicant states that the program will be enhanced to require reexaminations, and document that repairs meet the specified acceptance standards. The requirements for supplemental examinations, additional examinations, and documentation of acceptance criteria are parts of Subsection IWE of the ASME Code, as modified by 10 CFR 50.55a, and referenced in GALL Section XI.S1, "ASME Section XI, Subsection IWE. "Please provide clarification regarding the enhancements (to be implemented during the extended period of operation) which are currently not required.

RNP Response:

The site procedure for the IWE Program meets the requirements of IWA-4000, IWA-2200, and Table IWE-3410-1 for repairs and reexaminations, except as allowed by 10 CFR 50.55a(b)(2)(ix)(B) and approved requests for relief. However, an improvement was recommended to add the following statement to the IWE Program procedure: "Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1." This was recommended to clearly summarize the requirements in one location.

RAI B.3.13-2

Based on the database on degradation of moisture barrier between the concrete floor and the cylinder liner, Subsection IWE of Section XI of the ASME Code (as referenced in GALL Section XI.S1) requires 100% examination of moisture barrier once every inspection interval. During the IWE examinations, a number of licensees have discovered degradation of moisture barriers and significant corrosion of liner plates below the concrete floor levels. Please provide technical justification for the exception taken to the GALL program (i.e., one time inspection of this area).

RNP Response:

RNP has received NRC approval for relief from Subsection IWE of ASME Section XI. This is documented in a letter from Herbert N. Berkow (NRC) to D.E. Young (CP&L) dated July 26, 1999 titled, "Evaluation of Relief Requests IWE/IWL-1 through IWE/IWL-9: Implementation of Subsections IWE and IWL of ASME Section XI For Containment Inspection for Carolina Power and Light Company's H. B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP2) (TAC No. MA4637)." Relief Request IWE/IWL-01 has been approved to provide a VT-3 examination on those portions of the insulated moisture barriers and liner plate that are exposed when a maintenance activity requires removal of the insulation. Although Relief Requests IWE/IWL-01 and IWE/IWL-02 do not require examination of these "inaccessible" areas, 10 CFR 50.55a(b)(2)(ix)(A) does require the evaluation of these inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. These areas of the moisture barrier and containment liner were made accessible by removing the liner insulation and performing an examination. These areas were analyzed as stated in RNP Response to RAI 3.5.1-19 and determined not to impact the structural integrity or leak-tightness of containment. Some areas of the moisture barrier and liner plate are behind permanent structures, or due to ALARA concerns some could not be inspected. These inaccessible areas were analyzed and determined not to impact the structural integrity or leak-tightness of containment and determined to be acceptable for continued service until 2005, based on using worst case corrosion rates as discussed in the RNP Responses to RAI 3.5.1-7 and RAI 3.5.1-19. A one-time inspection was assigned for completing these inspections by year 2005. If additional inspections are required, they will be determined and scheduled at that time.

RAI B.3.13-3

The LRA is not clear on the acceptance criteria for bulging of the liner plate. Please provide acceptance criteria for bulging of the liner plate.

RNP Response:

The bulge in the containment liner was analyzed in the "HB Robinson Unit No. 2 Containment Liner Stress Analysis Report," dated June 21, 1974. A finite element approach was used for the liner and stud stress analysis. Broken adjacent stud anchors were postulated. Neither the stud load nor liner stress exceeded the allowable criteria of the materials used. The bulged liner and remaining anchor studs were determined to be effective to meet their functional requirements during a LOCA and during normal plant operating conditions. The bulge is believed to have been present since initial construction. A strain monitoring program was initiated for one cycle which indicated no gross movement or growth of the liner. A letter from E. Utley (CP&L) to Robert W. Reid (NRC), Serial NG-76-443, dated March 25, 1976, summarized the findings and provided a summary of the analysis used to demonstrate the integrity of the bulged liner. Two additional bulged liner areas were discovered in 1992. These areas are also believed to have existed since initial construction. These bulges were determined to be enveloped by the evaluation performed for the bulge discovered in 1974. These bulges were monitored in 1993 with negligible movement and were considered stable and acceptable, with no further monitoring required.

RAI B.3.13-4

Neither the LRA nor the UFSAR Supplement states the edition and addenda of the ASME Code being implemented. As amendment of UFSAR is a continuing process, it would be appropriate to state the edition and addenda of the ASME Code being used in the UFSAR Supplement. The relief requests granted from the specific edition and addenda of the Code should also be listed in the UFSAR Supplement (and in subsequent UFSAR addenda). Please provide this information and include it in the UFSAR Supplement, since the information is pertinent to the implementation of the program during the period of extended operation.

RNP Response:

The current code of record for the IWE/IWL Containment Examination Program is the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1992 edition through 1992 Addenda, subject to the limitations and modifications of 10 CFR 50.55a(b)(2). The current program comprises the first containment inspection interval and is effective from September 9, 1998 to September 8, 2008. The relief requests are listed in a letter from Herbert N. Berkow (NRC) to D. E. Young (CP&L), titled: "Evaluation of Relief Requests IWE/IWL-1 through IWE/IWL-9: Implementation of Subsections IWE and IWL of ASME Section XI For Containment Inspection for Carolina Power and Light Company's H.B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP2) (TAC No. MA4637)," dated July 26, 1999.

The first Containment Examination Program Interval (2008) ends prior to the extended period of operation (2010). During the extended period of operation, RNP will continue to meet the requirements of the Code incorporated by reference in 10 CFR 50.55a. Therefore, please note that the Code of record and relief requests will change prior to the extended period of operation.

In consideration of the above, the information in the first paragraph of LRA Subsection A.3.1.21, ASME Section XI, Subsection IWE Program, is modified to read:

> "The ASME Section XI, Subsection IWE, Program consists of periodic visual, surface, and volumetric inspection of steel containment components for signs of degradation, assessment of damage, and corrective actions. This program is in accordance with ASME Section XI, Subsection IWE, and in accordance with 10 CFR 50.55a(g), with modifications and approved relief requests."

RAI B.3.14-1

Because of the high acidity of the soil at the plant site, the staff considers the enhancement of requiring inspections of representative samples of underground concrete when excavating for maintenance to be appropriate. Please provide information regarding the present condition of the below grade concrete basemat based on the inspections that have already been performed (e.g., during maintenance activities).

RNP Response:

The soil at Robinson Nuclear Plant is considered aggressive because of the groundwater pH being slightly less than 5.5. This is considered to be slightly acidic, rather than highly acidic.

Below grade examinations of concrete have been performed at certain locations with satisfactory results. These include a below grade section of the RAB, internal surfaces of electrical manholes exposed to groundwater, submerged portions of the intake structure, and the dam spillway exposed to lake water. The lake water environment for the intake structure and dam spillway is essentially the same as that of aggressive ground water (pH values are both below 5.5); as such, inspection results in these areas should envelope aging effects encountered by below grade concrete of other structures, such as the containment basemat. In addition, an enhancement has already been made to a plant procedure, which requires an examination of any exposed concrete surfaces by engineering prior to backfilling. Please refer to the RNP Response to RAI 3.5.1-3 for more detailed discussion of lake water and groundwater chemistry.

RAI B.3.14-2

In forth finding under *Operating Experience* related to the containment concrete degradation, the LRA states, "An evaluation concluded that not providing cooling to the penetrations with hot piping does not degrade the concrete. Degradation has not occurred and does not require augmented examinations." Most of the high-temperature-related degradation would be in the concrete around the liner plate (or insert plate). Any degradation occurring in this area cannot be seen by visual examination. In this context, please provide the following information:

1) The sustained temperature in the concrete/liner interface around the hot penetrations,
2) Use of other NDE examination to ensure that the concrete on the back of the liner is not degraded.

RNP Response:

The maximum pipe temperature is 380°F, and the temperature of the sleeve and concrete was calculated as 208.5°F. This is conservative, since the calculation assumed 130°F ambient air over a period of 200 hours. The RHR system is in operation above 200 °F during cooldown for 10 hours, and for 22 hours during the heatup transient. These values are based on plant experience, rather than the 40 hours conservatively assumed in the plant calculation. After 22 hours, the temperature of the sleeve and concrete is at 162.3°F.

No other examinations have been completed or are planned for the affected concrete, other than those required in accordance with the ASME Section XI, Subsection IWL Program. A concrete surface examination of the area around the applicable RHR penetration (S-15) performed in May 2001 in accordance with the ASME Section XI, Subsection IWL Program identified some notches which had been cut out for small piping routed to the penetration. The inspection found no evidence of in-service degradation, and the inspection results were acceptable.

The concrete at the RHR penetration meets the design requirements as discussed in the RNP Response to RAI 4.6.3-2.

RAI B.3.14-3

Neither the LRA nor the UFSAR Supplement states the edition and addenda of the ASME Code being implemented. As amendment of UFSAR is a continuing process, it would be appropriate to state the edition and addenda of the ASME Code being used in the UFSAR Supplement. The relief requests granted from the specific edition and addenda of the Code should also be listed in the UFSAR Supplement (and subsequent addenda). Please provide this information and include it in the UFSAR Supplement, since the information is pertinent to the implementation of the program during the period of extended operation.

RNP Response:

Please refer to the RNP Response to RAI B.3.13-4. The information in the first paragraph of LRA Subsection A.3.1.22, ASME Section XI, Subsection IWL Program is modified to read:

> "The ASME Section XI, Subsection IWL Program consists of periodic visual inspection of concrete surfaces of reinforced and prestressed concrete containments for signs of degradation, assessment of damage, and corrective actions. This program is in accordance with the ASME Code Section XI, Subsection IWL, and addenda in accordance with 10 CFR 50.55a(g), with modifications and approved relief requests. The RNP prestressing tendons are grouted in place. Therefore, ASME Section XI Subsection IWL rules regarding unbonded post-tensioning systems are not applicable."

RAI B.3.15-1

If the Structures Monitoring Program manages the protective coatings that are relied upon to manage the effects of aging for structures and components, please describe the inspection program and address the following: (1) parameters monitored or inspected, (2) inspection interval, (3) inspection methods employed to detect change in material properties, (4) accept/reject criteria, and (5) operating experience to date with respect to degradation occurrences, corrective actions, and current activities.

RNP Response:

The Structures Monitoring Program is not credited for management of protective coatings.

RAI B.3.15-2

Appendix B.3.15 of the LRA contains a description of the structures monitoring program (SMP) for aging management of civil structures and components at RNP. The applicant identified aging effects (change in material properties due to elevated temperature and cracking due to elevated temperature) for elastomers (structural sealants). Please provide information on how the SMP manages the effects for elastomers through the effective incorporation of the following 10 attributes: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

RNP Response:

The level of information presented in the LRA was based on guidance provided in a letter from Pao-Tsin Kuo (NRC) to Alan Nelson (NEI), entitled: "Observations from the Nuclear Energy Institute (NEI) License Renewal Demonstration Project and Comments from an Advisory Committee on Reactor Safeguards (ACRS) Letter that May Result in Changes to NEI 95-10, Revision 3," dated July 24, 2002., Also, please see the RNP Response to RAI B3.10-10.

The elastomers identified in the LRA as being managed by the Structures Monitoring Program (SMP) are Table 3.5-2, Items 7 and 8. Items 7 and 8 are the commodities "seismic joint filler" and "roof (membrane or built-up)."
The SMP was developed to meet the requirements of 10 CFR 50.65, and was determined to be consistent with GALL, with enhancements as stated in Appendix B.3.15 of the LRA. The SMP manages a variety of components that include both GALL and non-GALL components. No distinction is made between GALL and non-GALL components within the SMP, and components are monitored using the same standards. The SMP manages aging of the seismic joint filler commodity by visual inspection to note any indication of movement or distress, as well as a determination that the gaps meet design requirements and are free of debris. The SMP manages aging of roof material by a visual inspection for degradation, damage, and/or leakage.

Although the subject items are not specifically identified in the GALL, no exceptions have been taken to the program attributes; They are consistent with the GALL program (with enhancements as noted in Appendix B.3.15). The GALL Program (XI.S6) for Structures Monitoring does not address specific commodities, materials, aging effects, or inspection attributes; rather, it states that parameters monitored or inspected, inspection methods, inspection schedules, and inspector qualifications are to be commensurate with industry codes, standards, and guidelines, and are also to consider industry and plant-specific operating experience. The aging management criteria associated with

the program attributes apply to any component/commodity within the scope of the program, regardless of whether it is a specific GALL commodity. The subject commodities are within the scope of the SMP and are managed to the same program attributes as GALL commodities.

RAI B.3.17-1

The LRA lists the aging effects that are covered by this program, but does not contain information related to the parameters monitored or inspected, detection of aging effects, monitoring and trending, or acceptance criteria. Please provide the above information for each aging effect that the Systems Monitoring Program will be used to manage.

RNP Response:

The applicable aging effects of concern are listed in the introduction to this section (see LRA page B-63). In addition to the aging effects listed, the Systems Monitoring Program will be enhanced to specifically include "Loss of Material due to Wear" as an aging effect/mechanism identified in the system walkdown checklist (see the RNP Response to RAI 3.3-1).

Parameters Monitored/Inspected

Surface conditions of piping, ductwork, and various other mechanical system components, including closure bolting, are monitored/inspected through visual inspection and examination for evidence of defects and age-related degradation. The parameters monitored or inspected are selected based on AMR results, including plant and industry operating experience, to ensure that aging degradation that could lead to loss of intended function will be identified and addressed. Inspections will detect and qualify degradations, including those aging effects identified in the AMR process. Identified aging effects include loss of material, cracking, and change in material properties. Piping and components in selected portions of systems are monitored through visual inspection for evidence of leaks. Flexible connectors (i.e., vibration isolators) are monitored for cracking or other changes in material properties (including wear). Air-cooled heat exchangers are monitored for fouling.

In Subsection A.3.1.25, Systems Monitoring Program, of the LRA, RNP committed to:

> *"Prior to the period of extended operation, administrative controls for the Program will be enhanced to: (1) include aging effects identified in the aging management reviews, (2) identify inspection criteria in checklist form, (3) include guidance for inspecting connected piping/components, (4) require that the extent of degradation to be recorded in the System Walkdown Report and that appropriate corrective action(s) are taken, and (5) add a section specifically addressing corrective actions."*

With enhancements (1) through (3) above, this program element is consistent with the corresponding element described in the Branch Technical Position.

Detection of Aging Effects

The aging effects of concern will be detected by visual inspection and examination of surfaces of piping, ductwork, and various other mechanical system components, including closure bolting, for evidence of defects and age-related degradation.

The Systems Monitoring Program relies on visual inspection of SSCs during system walkdowns to detect and qualify degradations. Degradations deemed to be "unacceptable" will have a condition report initiated and will be handled under the Corrective Action Program. Thus, the Systems Monitoring Program is designed to detect degradation prior to structure or component failure.

This element is consistent with the corresponding element described in the Branch Technical Position.

Monitoring and Trending

The Systems Monitoring Program is a condition monitoring program. Detailed system and component material condition inspections are performed in accordance with approved plant procedures in order to permit early detection of degradation. Accessible portions of maintenance rule and LR systems are walked down at least once per quarter. Walkdowns typically are scheduled and performed so the entire system is walked down within one operating cycle. Data obtained from system walkdowns is trended and evaluated to identify and correct problems. The results of monitoring and trending activities are documented and maintained in system notebooks.

This element is consistent with the corresponding element described in the Branch Technical Position.

Acceptance Criteria

Detailed system and component material condition inspections are performed in accordance with approved plant procedures. Existing procedures (with enhancements described below) include detailed guidance for inspecting and evaluating the material condition of systems, structures, and components within the scope of this program. The guidance includes specific parameters to be monitored and criteria to be used for evaluating identified degradation. Detailed documentation requirements, including checklists, ensures relevant information is recorded to allow identification and correction of age related degradation, and to provide adequate trending data.

With enhancements (4) and (5) identified in the discussion of "Parameters Monitored/Inspected" above, this program element is consistent with the corresponding element described in the Branch Technical Position.

RAI B.3.18-1

The staff has reviewed the program description for this aging management program, and is concerned that it's purpose may overlap the surveillance and maintenance activities associated with 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (e.g., the Maintenance Rule). In order to better understand how this aging management program will differ from, and supplement, the Maintenance Rule program, please discuss the surveillance and preventive maintenance activities that will be performed by this program, and how they will supplement activities performed under the Maintenance Rule. Please discuss the criteria to be used and the frequency of inspections in order to enable the staff to evaluate the effectiveness of the program in achieving its goals of aging management.

RNP Response:

Please refer to the RNP response to RAI B.3.18-2 for a list of surveillance and PM activities considered in the scope of the LR program.

The LR program scope does not directly supplement the Maintenance Rule Program. However, the activities may affect the performance of equipment in the scope of the Maintenance Rule Program. For example, a structure or component failure identified during the PM activity may result in functional failures under the Maintenance Rule. The performance of new or enhanced PMs or surveillances may improve component or system performance and thereby have a positive affect on the health of a system. At the same time, the new or enhanced PMs may adversely affect system unavailability due to increased demands of the activities. The net effect of these changes has not been evaluated with respect to the Maintenance Rule. These evaluations are likely to occur as the program enhancements are incorporated into the procedures and PM activities.

The Preventive Maintenance and Surveillance Testing Administration procedure requires PM optimization and continual improvement. This includes the evaluation of PM frequency, appropriateness of the PM activities, and to assess their effectiveness. Evaluations also compare these aspects with industry practices. Examples of factors used in determining PM frequencies are:

- Regulatory requirements (examples: Technical Specifications, Maintenance Rule, FSAR, NPDES)
- Vendor recommendations
- Experience with similar equipment
- Feedback from EPIX
- Engineering analysis of equipment performance

- INPO SOER recommendations or commitments
- Industry guidelines (examples: EPRI, NUMARC, NMAC, INPO)
- Industry standards (examples: IEEE, ASME, ANSI)
- Ability to repair the equipment on-line
- Ability to allow the equipment to run-to-failure
- Root cause results from previous or similar failure
- Requirements under specific engineering programs (Examples ISI, IST, MOV, AOV)

RAI B.3.18-2

The LRA lists the aging effects that are covered by this program, but does not contain information related to the parameters monitored or inspected, detection of aging effects, monitoring and trending, or acceptance criteria. Please provide the above information for each aging effect that the Preventative Maintenance Program will be used to manage.

RNP Response:

The following is a summary of current or future activities covered by PM procedures or detailed work order instructions. Required enhancements are identified and associated aging effects and mechanisms listed. Methods for detection of aging effects, parameters to be monitored or trended, and their associated quantitative or qualitative acceptance criteria are included in the particular PM and work order instruction. Frequency determination is based on several factors as described within the RNP Response to RAI B.3.18-1. Plant administrative procedures govern these activities and engineering personnel review the work history for these systems to ensure aging management concerns are properly documented and addressed.

ACTIVITY CREDITED	REQUIRED ENHANCEMENTS	AGING EFFECTS
Reactor Coolant System (RC)		
Periodically check the tension of RCP A, B, and C main flange bolting to ensure that stress relaxation has not occurred, and periodic examination / replacement of RCP seals.	None	Loss of Pre-load due to Stress Relaxation
Internal inspection of pressurizer relief tank lining every third refueling outage.	None	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Aggressive Chemical Attack
Steam Generator		
Inspect the subcomponents associated with the steam generator snubber reservoir in Snubber-1 through Snubber-12 for age related damage and replace components as required.	None	Change in Material Properties Cracking and Loss of Material due to Various Degradation Mechanisms
Feedwater System (FW)		
Inspect FW Heaters 6A/B for possible FAC and erosion.	Enhance PM to incorporate inspection for possible FAC and erosion.	Loss of Material due to FAC Loss of Material due to Erosion
Auxiliary Feedwater (AFW)		
Inspect MDAFW pump packing housing (stuffing box) cooling jacket to ensure no flow blockage or degradation from corrosion.	Establish a PM activity to ensure the stuffing box cooling water jackets are not fouled or degraded.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC Loss of Heat Transfer due to Fouling of Heat Transfer Surfaces
Clean and test MD and SD AFW Pump Oil Coolers	None	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC Loss of Heat Transfer due to Fouling of Heat Transfer Surfaces

ACTIVITY CREDITED	REQUIRED ENHANCEMENTS	AGING EFFECTS
Condensate System (CST)		
Inspect condition of the bladder inside the condensate storage tank and replace, if needed.	None	Change in Material Properties due to Elevated Temperature Cracking due to Elevated Temperature
Service Water System (SW)		
Periodically remove and replace service water pumps A, B, C and D.	None	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC
Periodically inspect per service water booster pump A and B pressure boundaries.	None	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
Periodically replace the ECCS room coolers, i.e., as a minimum cooling tubes/coils.	Establish a new PM to periodically replace the ECCS room coolers, i.e., as a minimum cooling tubes/coils	Note: Copper tubing has a site history of short life
Component/Closed Cooling Water System		
UT inspection of piping downstream of CCW throttle valves on return piping from the spent fuel pool heat exchanger (Pipe 10-AC-152N-41).	None	Loss of Material due to FAC Loss of Material due to Erosion
Inspect HVH-5A/5B outer surfaces of cooling coils for condition (corrosion, leakage, and fouling).	Enhance PM to inspect for corrosion, leakage, and fouling in cooling coil	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces
Diesel Generator System (DG)		
Replace flexible hoses/lines on diesel generators A and B, as required.	None	Change in Material Properties, Cracking and Loss of Material Due to Various Degradation Mechanisms
Periodically blowdown DG air start receiver to remove water from receiver and drain piping.	None	Loss of Material due to General Corrosion
Emergency diesel air start strainers S-33A, S-34A, S-33B, and S-34B cleaning and inspection for damage and wear.	None	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Cracking due to SCC

ACTIVITY CREDITED	REQUIRED ENHANCEMENTS	AGING EFFECTS
Clean and inspect emergency diesel air start strainers (S-32A/B and S-35A/B) for damage and wear.	Establish a PM to clean and inspect emergency diesel air start strainers (S-32A/B and S-35A/B)	Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Cracking due to SCC
Dedicated Shutdown Diesel Generator (DSD)		
Periodically blowdown the starting air receiver	None	Cracking due to SCC Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC
Perform a general inspection for leaks/condition of flexible hoses in the following systems: lube oil, jacket water, starting air and fuel oil.	Enhance PM to inspect and document condition of flexible hoses and initiate actions to replace, as necessary	Change in Material Properties Cracking and Loss of Material Due to Various Degradation Mechanisms
Fuel Oil System (FO)		
Flexible hoses for fuel oil system are addressed under PMs for other systems	None	
EOF/TSC Security Emergency Diesel Gen. (EOF DG)		
Inspect flexible hoses and replace as required.	None	Change in Material Properties Cracking and Loss of Material Due to Various Degradation Mechanisms
Instrument Air System (IA)		
Inspect for degradation of flexible hose used to make the terminal connections on air operators and replace as required.	Enhance PM to inspect and document condition of the following flexible hoses and initiate actions to replace, as necessary: PCV-455C, PCV-456, RV1-1, RV1-2 and RV1-3	Change in Material Properties and Cracking due to Elevated Temperature Change in Material Properties and Cracking due to Irradiation Embrittlement
Site Fire Protection System (SFPS)		
Periodically replace Diesel Driven Fire Pump and Motor Driven Fire Pump. Inspect inlet basket strainer.	Enhance PM activity to ensure the inlet basket strainer is cleaned, inspected, and replaced if necessary.	Flow Blockage due to Fouling Loss of Material due to Crevice Corrosion Loss of Material due to General Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion Loss of Material due to MIC

ACTIVITY CREDITED	REQUIRED ENHANCEMENTS	AGING EFFECTS
EDG Cardox System (CARDOX)		
Replace the flex lines on the emergency diesel CO_2 manifolds.	None	Corrosion, damage or degradation for any cause.
Fire Protection CO_2 System (CO2)		
Replace the flex lines on the main and reserve CO_2 manifolds.	None	Corrosion, damage or degradation for any cause.
Halon Supply System (HALON)		
Replace the flex lines on the main and reserve Halon manifold.	None	Corrosion, damage or degradation for any cause.
Potable Water System (PWS)		
Inspect, and if necessary, repair and replace Potable Water (PW) System components located in cable spread room, E1/E2 area and in the battery room.	Establish a PM activity to inspect, and if necessary, repair/replace PW system components located in the cable spread room, E1/E2 area and in the battery room	Loss of Material due to General Corrosion Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to Galvanic Corrosion
Liquid Waste Processing System (WDS) and Isolation Valve Seal Water System (IVSW)		
Check for pressure boundary leakage in valves, piping, and fittings. (Valves WD-1728, WD-1723, and IVSW-89)	None	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
HVAC Containment Building System (HVAC)		
Visually inspect the stainless steel airsides of HVH-1, HVH-2, HVH-3, and HVH-4 tubes for leaks and degradation of the pressure boundary. Visually inspect housing, and ductwork for leaks and corrosion.	Enhance surveillance test to include an inspection of the airside of motor heat exchanger for degradation and corrosion.	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
HVAC Auxiliary Building (HVAC)		
Inspect HVH-6A/B, HVH-7A/B, and HVH-8A/B equipment frames and housings and heating/cooling coils for condition (corrosion and leakage).	None	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to General Corrosion Loss of Material due to MIC
Visually inspect EAC-3 and HC-2 coils for condition and leaks. Visually inspect filter F-49 equipment frame for degradation and housing for degradation and / or pressure boundary Visually inspect housing, and ductwork for degradation, leaks and corrosion. Inspect dampers for damage to housing.	None	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to General Corrosion Loss of Material due to MIC
Visually inspect equipment housing of filters F-35A, F-35B, F-40A, and F-40B for leaks and corrosion or	None	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion

ACTIVITY CREDITED	REQUIRED ENHANCEMENTS	AGING EFFECTS
degradation of pressure boundary Visually inspect system housing and ductwork for leaks, corrosion and degradation. Inspect dampers for damage to housing, e.g., corrosion.		Loss of Material due to General Corrosion Loss of Material due to MIC
HVAC Control Room Area (HVAC)		
Inspect AHU-1 housing (drip pan) for corrosion and leaks.	None	Loss of Material due to Crevice Corrosion Loss of Material due to Pitting Corrosion Loss of Material due to MIC
Bldg 205: Reactor Auxiliary Building		
Conduct routine monitoring of the cable coatings installed on cable trays within the fire zones that comprise the RAB to ensure that no notable loss or degradation of the coating system has occurred.	Establish a PM to inspect cable trays within the RAB fire zones to ensure no notable loss or degradation of the coating system.	Loss of Material due to Flaking
Various Electrical Systems		
Perform visual inspections of readily accessible cables and connections not included in the RNP EQ Program.	Establish PMs to implement the Non-EQ Insulated Cables and Connections Program (LRA Section B.4.6).	Embrittlement, cracking, melting, discoloration or swelling leading to reduced insulation resistance or electrical failure

RAI B.3.19-1

Section B.3.19 of the LRA discusses the discovery of several additional thermal transients not originally considered in the RNP design. The second sentence under *Operating Experience* defines the scope of lines (systems) under NRC Bulletins 88-08 and 88-11, and additional fatigue analyses performed to account for additional thermal transients associated with each of these issues. Please clarify the scope defined in the second sentence and identify any enhancements to the RNP plant specific Fatigue Monitoring Program that resulted from the industry operating experience relating to thermal fatigue and component degradation.

RNP Response:

A fatigue analysis of the pressurizer surge line was prepared to consider thermal stratification loadings described in NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." The analysis included the surge line piping and the RCS hot leg nozzle, and the study of surge line behavior concluded that the largest temperature differences occur during certain modes of plant heatup and cooldown. Plant-specific evaluations were performed for RNP for surge line stratification transients and profiles used in the fatigue analyses. The analysis was based on the same number of occurrences of the design basis transients (such as heatups and cooldowns) as before; the calculated fatigue usage increased, but remained below the design limit of 1.0. The Fatigue Monitoring Program was not affected because the transient limits were not changed as a result of the revised fatigue analysis.

In 1994, a pressurizer transient occurred that exceeded plant Technical Specifications limits. A detailed evaluation was performed that included the definition of a number of past out-of-limit pressurizer transients, the definition of enveloping transients, a determination of stresses in critical locations in the pressurizer lower head, and an evaluation of these stresses on the structural integrity of the pressurizer. Locations evaluated included the lower head, heater wells, instrument nozzles, the surge nozzle, and surge nozzle safe end. A fatigue evaluation was performed demonstrating that the increase in fatigue usage from these transient events was small, and that the out-of-limit transients did not compromise the structural integrity of the pressurizer. Each of these components were shown to have a 40-year CUF value below 1.0. The analysis was based upon the use of improved operational practices for future heatups and cooldowns, but included significant margin for additional insurge/outsurge events beyond the number that had occurred previously. Again, the Fatigue Monitoring Program was not affected because the transient limits were not changed as a result of the revised fatigue analysis.

Plant-specific monitoring of the surge line was later performed during one operating cycle, and the analyses were further updated to incorporate the measured data, which resulted in increased fatigue usage. The limiting location is the RCS hot leg nozzle, with a 40-year CUF value of 0.96. Once again, the Fatigue Monitoring Program was not affected because the transient limits were not changed as a result of the revised fatigue analysis.

No component analyses were affected by NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to the Reactor Coolant Systems." CP&L completed an evaluation of the systems connected to the RCS at RNP and determined that there are no unisolable piping systems that have the potential for inducing unacceptable thermal stresses as defined in NRC Bulletin 88-08. A further review was completed in response to Supplement 3 of NRC Bulletin 88-08, and no piping was identified which could be subjected to unacceptable thermal stratification due to valve and piping configurations similar to that identified within Supplement 3. This review concluded that, due to design and operational differences between RNP and the Supplement 3 configuration, the potential for a similar occurrence at RNP is not a concern. Therefore, no revisions were made to the fatigue design basis of these lines, and no changes were required for the Fatigue Monitoring Program.

RAI B.3.19-2

Section B.3.19 of the LRA, under *Conclusion*, states that the pressurizer surge line (and the nozzles) was not shown to have an environmentally-adjusted CUF less than 1.0 and fatigue effects will be managed by periodic examinations in accordance with ASME Section XI. Referring to RAI 4.3-9, the inspection program can not be considered adequate unless the applicant can demonstrate that the examinations, at the prescribed interval, will be able to detect the initiation of fatigue cracking which will not become unstable. Please provide this demonstration.

RNP Response:

Please refer to the RNP Response to RAI 4.3-10.

RAI B.3.19-3

Please clarify whether the Fatigue Monitoring Program at RNP covers the environmental effects, and describe the methodology employed to account for the environmental effects on the CUF calculations at RNP.

RNP Response:

The RNP Fatigue Monitoring Program tracks the number of thermal cycles that have occurred for each significant thermal transient type (heatups, cooldowns, etc.) and compares these cumulative totals to the applicable design limits. The present design limits are based upon the number of thermal cycles postulated in the CLB fatigue analyses for Class 1 components at RNP. If the CLB fatigue analyses are revised, and if a reduced number of transients is used as an input assumption in the revised analysis, the fatigue monitoring program cycle limit is changed accordingly prior to exceeding the reduced limit.

The RNP Fatigue Monitoring Program will account for environmental effects prior to the period of extended operation. Environmental fatigue calculations were performed for the seven locations specified in NUREG/CR-6260 and for seven locations inside the pressurizer using the fen methodology contained in NUREG/CR-6583 for carbon/low alloy steel material, and in NUREG/CR-5704 for stainless steel material. The number of load/unload cycles used as an input to one of the environmental fatigue calculations was reduced from 29,000 to 19,000. The fatigue monitoring program limit for load/unload cycles will be reduced accordingly prior to the period of extended operation, thereby incorporating the environmental fatigue calculations into the fatigue monitoring program. The UFSAR update includes this change. (Note: The cumulative number of load/unload cycles to date is less than 1,000.)

Pressurizer surge line components which have not been shown to have an EAF-adjusted CUF value less than 1.0 will be managed separately by the ASME Section XI, ISI Program (see the RNP Response to RAI 4.3-10).

RAI B.4.1-1

Under "Nickel-Alloy Nozzles and Penetration Program," it is stated that RNP will commit to continuing the resolution of reactor vessel head penetration issues through the period of extended operation and will participate in industry initiatives (Westinghouse Owners Group and the EPRI Material Reliability Program) to ensure that the components managed are maintained within the CLB during the period of extended operation. To ensure that RNP's Nickel-Alloy Nozzles and Penetration Program will be capable of monitoring, detecting, evaluating any flaws in the Class 1 Nickel-based Alloy nozzles, and to ensure that the integrity of these components will be maintained during the extended period of operation for RNP, confirm whether CP&L is committed to implementing all NRC-approved inspection method activities, inspection frequencies, and evaluation criteria that are recommended as a result of the industry's assessment initiatives on Inconel materials, as well as any further requirements that may result from the NRC staff's resolution of the industry's responses to NRC Bulletins 2002-01 and 2002-02, and/or resolution of the V. C. Summer issue.

RNP Response:

As stated in LRA Subsection A.3.1.28, Nickel-Alloy Nozzles and Penetrations Program, RNP commits to the following for the Nickel-Alloy Nozzles and Penetrations Program:

> *"Prior to the period of extended operation, the Nickel-Alloy Nozzles And Penetrations Program will incorporate the following: (1) CP&L will perform evaluation of indications under the ASME Section XI program, (2) CP&L will perform corrective actions for augmented inspections to repair and replacement procedures equivalent to those requirements in ASME Section XI, (3) CP&L will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group and the EPRI Materials Reliability Project) during the period of extended operation."*

This commitment will be supplemented as follows:

> "(4) RNP will submit, for review and approval, the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, since .... implemented from the applicant's participation in industry initiatives prior to July 31, 2009."

RAI B.4.1-2

Under "Nickel-Alloy Nozzles and Penetrations Program", it is stated that RNP will make enhancement to the program by performing corrective actions for augmented inspections using repair and replacement procedures equivalent to those requirements in ASME Section XI. Please confirm if RNP is committed to comply with the ASME Code, Section XI, IWB-4000 for repair of components found to contain cracks and IWB-7000 for replacement of components identified as susceptible to primary water stress corrosion. Please justify RNP's planned enhancement to the program with the Code-equivalent repair procedure.

RNP Response:

Please refer to the RNP Response to RAI B.4.1-1 regarding submittal of the inspection plan.

RAI B.4.2-1

In UFSAR supplement summary for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS Program) you state that the flaw tolerance evaluations for RCP casings and primary loop CASS components have been done in accordance with a fracture toughness methodology that has been approved by the NRC, and that, consistent with NRC guidance, the RNP Program does not include additional inspections of pump casings, valve bodies, or piping. Clarify which fracture toughness methodology and NRC guidance you are referring to in your UFSAR supplement summary for the CASS Program, and provide your basis why your program is consistent with the NRC guidance. Clarify what type of inspections will be done on CASS pump casing, valve bodies, and piping to ensure that cracking of the CASS materials will be detected prior to crack growth in excess of the critical crack size for components, as assessed for thermal aging in the component materials.

RNP Response:

Please refer to the Operating Experience discussion in LRA Appendix B, Subsection B.4.2, for a discussion of flaw tolerance evaluations using NRC-approved methods. The methodology is based on evaluations performed by Argonne National Laboratory (ANL). The ANL work is discussed in a letter from C. Grimes (NRC) to D. Walters (Nuclear Energy Institute), dated May 19, 2000, which is referenced in the Scope of Program section of GALL XI.M.12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," in NUREG-1801, Generic Aging Lessons Learned (GALL) Report, April 2001. The methodology was used for RNP-specific analyses of reactor coolant system piping and reactor coolant pump casings. The plant-specific analyses are summarized in LRA Appendix A, Subsection A.3.2.5.

The NRC guidance referenced in LRA Subsection A.3.1.29 is from the GALL Report regarding additional inspections of pump casings, valve bodies, and piping. The guidance is discussed in the Detection of Aging Effects section of program XI.M.12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

Inspection of valves, piping/fittings, and pump casings, performed under the Section XI Program, in accordance with IWB-2400 or IWC-2400, provides timely detection of cracks. Consistent with NRC guidance, the RNP program does not include additional inspections of pump casings, valve bodies, or piping. An evaluation has been performed demonstrating the applicability of Code Case N-481 (which incorporates surface exams) to RCP casings over the period of extended operation. Also a flaw tolerance evaluation has been performed for RCS loop piping during the period of extended operation, which includes consideration of fracture toughness and thermal aging of CASS components.

The evaluation demonstrates margin between detectable flaw size and flaw instability. Accordingly, an inspection program to manage this effect for primary loop piping/fittings is not warranted.

RAI B.4.3-1

The discussion provided in Section B.4.3 of Appendix B to the LRA does not provide any specific details on how the RNP PWR Vessel Internals Program will manage a number of aging effects for the RNP RV internal components. Provide additional specific details on how the RNP PWR Internals Program will manage the following effects in the RNP RV internal components:

- void swelling
- loss of material, loss of preload and cracking in the RNP RV internal bolted or fastened connections, including baffle/former bolts
- loss of material and loss of preload in components such as hold-down springs and clevis inserts, as applicable
- cracking in RV internals made from austenitic alloys (inconel alloys and/or austenitic stainless steel alloys) and loss of fracture toughness in RV internals made from CASS or in RV internals made from austenitic alloys with neutron fluences projected to be above $5x10^{20}$ n/cm^2

Include in your assessment of these aging effects, a clarification of the type of inspection methods will be used to monitor for the aging effects, the frequency of inspections and the components the inspections will be performed on, the methods that will be used to qualify a given inspection method to detect the aging effect in question, and what acceptance criteria will be used to initiate corrective actions if any of these aging effects are detected in the RV internal components. If industry participation is to be used as a basis for determining whether inspections are necessary for monitoring of these aging effects, a commitment is requested from CP&L to implement the inspections methods, inspection frequencies, inspection qualification techniques, and acceptance criteria for these aging effects as recommended by Westinghouse, applicable MRP ITGs, or other relevant industry organizations for management of these aging effects.

In addition, for the inspection RV internal baffle bolts, the staff's recommended position in GALL Program XI.M16, "PWR Vessel Internals Program," is that VT-3 examinations have not been capable of identifying cracks at the junctures of the baffle bolt heads and shanks. The GALL program, therefore, recommends that more stringent augmented inspection techniques, such as enhanced VT-1 visual methods or ultrasonic examination techniques be used to inspect the shanks of the baffle bolts below the bolt heads and the regions of the bolthead-shank junctures. The staff requires assurance that the inspection methods selected for the RV internal baffle bolts will be capable of detecting cracking in these regions. As a minimum, the staff either requests that CP&L either commit to performing a one-time enhanced VT-1 or UT inspection of the baffle bolt shanks and bolthead-shank junctures or else provide additional clarification how the commitment to implement the recommended inspection methods and frequencies from industry

initiatives on PWR vessel internal baffle bolts will ensure that cracking in the shanks and the shank-bolthead junctures will be detected.

RNP Response:

Industry consensus on acceptable inspections techniques for reactor vessel internals aging mechanisms has not been reached. Previous applicants have committed to participating in industry activities to characterize the aging mechanisms and determine appropriate inspection techniques.

In Subsection A.3.1.30, PWR Vessel Internals Program, of the LRA, RNP commits to the following for the PWR Vessel Internals Program:

> *"This is a new program that will incorporate the following commitments (1) To address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP, (2) To address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the Baffle and Former Assembly, (3) As WOG and EPRI Materials Reliability Project (MRP) research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques, (4) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Section XI."*

In the RNP Response to RAI B.4.3-2, RNP has supplemented this commitment as follows:

> "RNP will submit, for NRC review and approval, the inspection plan for the PWR Vessel Internals Program, as it will be implemented based on participation in industry initiatives, 24 months prior to the augmented inspection."

RAI B.4.3-2

The staff seeks a commitment from the applicant that, prior to period of extended operation, the applicant will submit for review and approval its inspection plan for the PWR Vessel Internals Program, as it will be implemented from the applicant's participation of industry initiatives on PWR RV internal components and its commitment to implement of the recommended inspection activities, frequencies, and acceptance criteria that will result from these initiatives. Amend your FSAR Supplement summary description for the PWR Vessel Internals Program to incorporate this commitment, including specification of the date when the inspection plan will be submitted by the applicant. In addition, amend your FSAR Supplement summary description for the PWR Vessel Internals Program to reflect the information provided in the applicant's response to RAI B.4.3-1.

RNP Response:

The RNP UFSAR Supplement, Appendix A, Subsection A.3.1.30, will be revised to include the statement that the PWR Vessel Internals Program, including recommended inspection activities, frequencies, and acceptance criteria, based on participation in industry initiatives on PWR RV internal components, will be submitted for NRC review prior to the augmented inspection.

In Subsection A.3.1.30, PWR Vessel Internals Program, of the LRA, RNP committed to:

> *"This is a new program that will incorporate the following commitments (1) To address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP, (2) To address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the Baffle and Former Assembly, (3) As WOG and EPRI Materials Reliability Project (MRP) research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques, (4) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Section XI."*

This commitment will be supplemented as follows:

"RNP will submit, for NRC review and approval, the inspection plan for the PWR Vessel Internals Program, as it will be implemented based on participation in industry initiatives, 24 months prior to the augmented inspection."

RAI B.4.6-1

In the LRA, the applicant stated that "the Non-EQ Insulated Cables and Connections Program is credited for aging management of cables and connections not included in the RNP EQ Program." It is not clear to the staff how the aging of the Electrical/I&C penetration assemblies are managed by this program, since the scope of the program does not include the penetration assemblies.

RNP Response:

As discussed in LRA Subsection 3.6.2.1, the components subject to aging in the electrical penetration assemblies are the materials for the electrical conductors and connections.

RAI B.4.6-2

In the LRA, the applicant stated that the sample locations will consider the location of PVC cables inside and outside containment as well as any known adverse localized environments. It is not clear to the staff that the sample will include other types of cables that may be located in adverse localized environments.

RNP Response:

The Non-EQ Insulated Cables and Connections Aging Management Program is a condition monitoring program designed to provide reasonable assurance that age-related degradation will not inhibit the intended function of insulated cables and connectors within the scope of license renewal during the period of extended operation. The scope of this program includes plant cables of various insulation material types (not just PVC) that may be located in an adverse, localized environment. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the cable or connection. The aging effects managed are embrittlement, cracking, melting, discoloration, swelling, or surface contamination that could lead to reduced insulation resistance or electrical failure.

RAI B.4.6-3

In the RLA, the applicant stated that the scope of Program for the Non-EQ Insulated cables and Connections Program will also be applied to instrument cable insulation, as addressed in Section XI.E2 of the GALL Report; however, the calibration of instrument circuits for the purpose of detecting insulation degradation, as called for in Section XI.E2, is not part of the RNP program. The staff's position on this issue is, a reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument loop. Please refer to RAI 3.6.1-D2 for details. Please clarify this issue.

RNP Response:

RNP will implement aging management programs to address the reduction in IR for high-range radiation monitoring and neutron flux instrumentation circuits. These are two (2) separate but related programs.

The RNP Response to RAI 3.6.1-2 describes the aging management programs for the high-range radiation monitoring and neutron flux instrumentation circuits. Also provided within that response are the associated program updates to the UFSAR Supplement, Appendix A.