RAI 3.1.2.4.1-1

Column 1 of AMR Item 2 to LRA Table 3.1-2 provides a list of stainless steel and nickel-based alloy RCS components that may be susceptible to loss of material by crevice or pitting corrosion. The list of components in column 1 of AMR Item 2 is somewhat confusing (i.e., it is difficult for the staff to discern one component from the next). Clarify which specific RCS components are included under to the scope of column 1 to AMR Item 2 in LRA Table 3.1-2.

RNP Response:

The following is a list of specific components under the scope of LRA Table 3.1-2, Item 2 (grouped by system):

Primary Sampling System

- Valves, Piping and Fittings

Reactor Vessel And Internals System

- A2.1.1 Dome Cladding
- A2.3.1 Nozzles - Inlet Cladding
- A2.3.2 Nozzles - Outlet Cladding
- A2.5.1 Vessel Shell - Upper Shell Cladding
- A2.5.2 Vessel Shell - Inter. And Lower Shell Cladding
- A2.5.3 Vessel Shell - Vessel Flange Cladding
- A2.5.4 Vessel Shell - Bottom Head Cladding
- A2.4.1 Nozzles - Safe End (Inlet)
- A2.4.2 Nozzles - Safe End (Outlet)
- B2.6.1 Flux Thimble Guide Tubes
- Seal Table Valves and Fittings
- A2.1.2 Head Flange Cladding
- A2.2.2 CRD Head Penetration Pressure Housing
- A2.2.1 CRD Head Penetration Nozzle
- A2.6 Core Support Pads
- A2.7.1 Penetrations - Instrumentation Tubes (Bottom Head)
- A2.7.2 Penetrations - Head Vent Pipe
- B2.6.2 Flux Thimbles
- A2.7.3 Penetrations - Instrumentation Tubes (Top Head)

Reactor Coolant System

- Valves, Piping, Tubing and Fittings
- C2.5-f (C2.5.5, C2.5.6, C2.5.7) PZR Thermal Sleeves, Instrument Nozzle, Safe End
- C2.5-h (C2.5.7) Pressurizer Safe Ends
- C2.5-q, C2.5-r (C2.5.10) Pressurizer Immersion Heater Sheaths/Sleeves
- C2.5-g (C2.5.6) Pressurizer Instrument Nozzles
- C2.5-m (C2.5.8) Pressurizer Manway Insert
- C2.5-a and C2.5-c (C2.5.1) Pressurizer Shell/Heads
- C2.5-d (C2.5.2) Pressurizer Spray Nozzle
- C2.5-e (C2.5.3) Pressurizer Surge Nozzle
- C2.5-g (C2.5.2, C2.5.3) PZR Spray and Surge Nozzles

Residual Heat Removal System

- Valves, Piping, Tubing and Fittings

CVCS

- Valves, Piping, Tubing and Fittings

SI System

- Piping and Fittings

Steam Generator

- D1.1-h (D1.1.8, Lower Head Cladding)
- D1.1-h, D1.1-i (D1.1.9, Primary Nozzles Cladding and Safe Ends)
- Steam Generator Primary Manway Insert
- Steam Generator Lower Head Divider Plate
- Steam Generator Tubeplate Cladding

RAI 3.1.2.4.1-2

In order to be consistent with Renewal Applicant Action Item 3.2.2.1-1 of the staff's safety evaluation on WCAP-14574 dated October 26, 2002, provide your basis as to how implementation of RNP water chemistry control program is sufficient to provide for a level of hydrogen over-pressure in the RCS, and how this level of hydrogen overpressure will be capable of managing crevice or pitting corrosion in the internal surfaces of the Class 1 RCS components that are exposed to the borated reactor coolant.

RNP Response:

RNP does not credit WCAP-14574 in the LRA for Class 1 RCS components. Therefore, a specific response for Action Item 3.2.2.1-1 of the safety evaluation is not required. However, hydrogen concentrations in the RNP RCS are strictly maintained within specified limits by measurement of hydrogen concentrations in periodic RCS samples, and adjusting hydrogen overpressure in the volume control tank accordingly. The hydrogen concentration limits established for the RCS ensure that corrosion is non-significant for the internal surfaces of the RNP pressurizer as well as other Class 1 components. This is stated in LRA Table 3.1-2, Item 2. As discussed in LRA, B.2.2 (Water Chemistry Program), the overall effectiveness of the Water Chemistry Program is supported by the operating experience for systems, structures and components, which are influenced by the Water Chemistry Program. No chemistry-related degradation has resulted in loss of component intended functions on systems for which the fluid chemistry is actively controlled.

RAI 3.1.2.4.1-3

You provide your aging management review for carbon steel non-Class 1 piping, valve and fitting components that are exposed to air and gas environments in AMR Item 8 of Table 3.1-2 of the LRA. In this AMR Item you state that this component/ commodity group consists of valves, piping, and fittings associated with lines connected to the pressurizer relief tank and that these components are subject to a dry, inert nitrogen environment on their internal surfaces. You concluded that these valves, piping, and fitting components have no aging effects resulting from this environment. The staff concurs that aging should not occur in the surfaces of carbon steel components that are exposed to inert, dry nitrogen environments. In LRA Table 3.1-2, the scope of AMR Item 8 covers non-Class 1 components made from carbon steel under exposure to air and gas environments, but only discusses the potential for aging to occur under the dry, internal nitrogen environment. Your AMR for this commodity group does not address the potential for aging to occur in the components under exposure to external air or gas environments. With respect to AMR Item 8 of Table 3.1-2 of the LRA, clarify whether you have performed an AMR for the components within this commodity group under exposure to external air or gas environments. If you have performed such an AMR, clarify which Table and AMR Item in the application contains the AMR. If an AMR has not been performed, provide your AMR for the RCS piping, valve, and fitting components that are within the scope of this commodity group and are exposed externally to air or gas environments, and identify all applicable aging effects for these components under these environments. State which aging management programs will be credited for these components, if aging effects are determined to be applicable for these components under exposure to the external air or gas environments.

RNP Response:

Item 8 of LRA Table 3.1-2 pertains only to the internal environments for the subject valves, piping, and fittings. The external surfaces of these non-Class 1 carbon steel valves, piping, and fittings were included in LRA Table 3.1-1, Item 26. The only aging effect/mechanism identified for the external surfaces of these components is "Loss of Material due to Aggressive Chemical Attack." Consistent with GALL, this aging effect is managed by the Boric Acid Corrosion Program. RNP also applied fatigue to these valves, piping, and fittings in an air and gas environment. Fatigue is a TLAA addressed by LRA Table 3.1-1, Item 1.

Unless otherwise subjected to "Aggressive Chemical Attack," carbon steel components located in areas protected from weather and not subject to condensation do not require aging management review. See the RNP Response to RAI 3.2.1-1 for additional information in this regard.

RAI 3.1.2.4.1-4

Column 1 of AMR Item 17 of LRA Table 3.1-2 does not clearly indicate which RCS piping, valve, and fitting components are within the scope of the AMR. For confirmation, clarify exactly which components are within the scope of AMR Item 17 of LRA Table 3.1-2.

RNP Response:

As identified in LRA Tables 2.3-1, 2.3-2, and 2.3-10, the following components are under the scope of LRA Table 3.1-2, Item 17:

RCS (Including Reactor Vessel and Internals System)

- Stainless steel seal table valves and fittings.
- Stainless steel flow orifices/elements within the RCS.
- Stainless steel valves, piping, tubing and fittings within the RCS.

CVCS

- Stainless steel flow orifices/elements within the CVCS.
- Stainless steel valves, piping, tubing and fittings within the CVCS.

RHR

- Stainless steel valves, piping, tubing and fittings within the RHR System.

Reactor Vessel Level Instrumentation System

- Stainless steel valves, piping, tubing and fittings within the Reactor Vessel Level Instrumentation System.

RAI 3.1.2.4.1-5

In AMR 17 of LRA Table 3.1-2, CP&L concluded that there were no applicable aging effects for the external surfaces of the stainless steel RCS piping, valve, and fitting components that are exposed to Indoor-not air conditioned or containment air environments. CP&L, however, did not provide any technical basis for making this conclusion. Provide the technical basis why CP&L does not consider aging effects (i.e., loss of material and/or cracking) to be applicable for the external surfaces of stainless steel RCS piping, valve, and fitting components (including tubes, orifices, and flow restrictors) that are exposed to either the Indoor-not air conditioned or containment air environments. If aging effects are applicable for the external surfaces of the stainless steel RCS piping, valve, and fitting components (including tubes, orifices, and flow restrictors) that are exposed to either the Indoor-not air conditioned or containment air environments, identify what the aging effects are, and state which aging management programs will be credited with managing the aging effects during the extended period of operation for RNP.

RNP Response:

The specific components within the scope of LRA Table 3.1-2, Item 17, are described in the RNP Response to RAI 3.1.2.4.1-4. Consistent with GALL, no aging effects/mechanisms have been identified for the external surfaces of these stainless steel components. The RNP aging management review considered material, environment, and operating parameters for the subject components and is based upon industry guidance and plant specific experience regarding aging effects of stainless steel components.

RAI 3.1.2.4.1-6

Column 1 of AMR Item 18 of LRA Table 3.1-2 implies that the stainless steel RCS piping, tube, and fitting components are within the scope of the AMR are limited to those in the Non-Class 1 reactor vessel instrumentation lines. Confirm that the stainless steel RCS piping, tube, and fitting components within the scope of AMR Item 18 of LRA Table 3.1-2 are limited to those in the Non-Class 1 reactor vessel instrumentation lines.

RNP Response:

The stainless steel piping, tube, and fitting components within the scope of Item 18 of LRA Table 3.1-2 are limited to those in the Non-Class 1 Reactor Vessel Level Instrumentation System lines.

RAI 3.1.2.4.1-7

In AMR 18 of LRA Table 3.1-2, CP&L concluded that there no applicable aging effects for the surfaces of the stainless steel piping, tube and fitting components in the reactor vessel instrumentation lines that are exposed internally to treated water or steam environments because the components are isolated from the portions of the RCS that are exposed internally to treated water and are instead exposed to purified deionized water. The staff concurs that austenitic stainless steel materials are designed to be resistant to corrosion in purified deionizied water and that aging effects are not applicable for the internal surfaces of the stainless steel piping, tube and fitting components in the reactor vessel instrumentation lines if purified, deionized water is the applicable internal environment for the stainless steel components in the Non-Class 1 reactor vessel instrumentation lines. However, if purified deionized water is the applicable environment for the stainless steel piping, tube and fitting components in the reactor vessel instrumentation lines, amend column 3 of AMR Item 18 of LRA Table 3.1-2 to state that purified, deionzied water is the applicable internal environment for the stainless steel piping, tube and fitting components in the Non-Class 1 reactor vessel instrumentation lines.

RNP Response:

RNP confirms that the environment for LRA Table 3.1-2, Item 18, is purified, deionized water.

RAI 3.1.2.4.3-1

In AMR Item IV.C2.6-a of GALL, Volume 2, the staff states that fatigue is an applicable effect for pressurizer relief tanks that are fabricated from carbon steel material and are exposed internally to chemically treated borated water. In contrast to the staff's AMR provided in AMR Item IV.C2.6-a of GALL, Volume 2, CP&L did not provide, in either Table 3.1-1 or 3.1-2 of the LRA, an AMR which listed that fatigue as an applicable aging effect for the pressurizer relief tanks. Provide your technical basis why CP&L does not consider fatigue to be an applicable aging effect for the internal surfaces of the RNP pressurizer relief. If fatigue is considered to be an applicable aging effect for the RNP pressurizer relief tank, provide a amended AMR that lists fatigue as an applicable aging effect for the internal surfaces of the pressurizer relief tank that are exposed to chemically treated borated water or steam, and state the aging management program or time-limited aging analysis that will be credited with managing fatigue in the RNP pressurizer relief tank through the expiration of the period of extended operation for RNP.

RNP Response:

The normal operating temperature of the pressurizer relief tank is less than 150°F. Therefore, fatigue is not considered to be an applicable aging effect.

RAI 3.1.2.4.3-2

In AMR Item IV.C2.6-b of GALL, Volume 2, the staff states that loss of material due to boric acid corrosion is an applicable effect for external surfaces of pressurizer relief tanks fabricated from carbon steel material and that can be exposed to leaks of chemically treated borated water from the pressurizer relief tanks. Confirm that loss of material from the external surfaces of the RNP pressurizer relief tank due to leakage of the borated treated water is addressed under the scope of AMR Item 26 in Table 3.1-1 of the LRA.

RNP Response:

As indicted by the reference to LRA Table 3.1-1, Item 26 within LRA Table 2.3-1, the loss of external material from the pressurizer relief tank due to boric acid corrosion is an applicable aging effect to be managed by the Boric Acid Corrosion Program.

RAI 3.1.2.4.4-1

In AMR Item IV.A2.7-a of GALL, Volume 2, the staff identifies that crack initiation and growth due to PWSCC are applicable aging effects for Alloy 600 RV bottom head instrumentation tubes and states that either a plant specific AMP is to be proposed to manage these effects or an applicant is to indicate that it will participate in industry-wide programs that will evaluate and determine the appropriate type of AMPs that will be used to manage crack initiation and growth in these components. Industry experience has demonstrated that PWSCC can occur in Alloy 600 components (e.g., steam generator tubes or CRDM penetration nozzles in PWRs) in spite of controlled maintenance of reactor coolant chemistry. The CP&L AMR (AMR Item 10 in LRA Table 3.1-2) for the bottom head instrumentation tubes is not consistent with GALL because CP&L has proposed to manage crack initiation and growth in the tubes using the chemistry program and the ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program. The only ISI requirements for the RV bottom head instrumentation tubes are requirements for VT-2 visual leakage examinations for the tube nozzles once every refueling outage. Justify how the ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program, and specifically how the VT-2 methods prescribed by Inspection Category B-P of ASME Section XI Table IWB-2500-1, when taken in conjunction with the chemistry program, will be sufficient to manage PWSCC-induced crack initiation and growth in the Alloy 600 RV bottom head instrumentation tubes prior to a postulated loss of pressure boundary function. Otherwise propose a plant-specific AMP to manage these effects in the RV bottom head instrumentation tubes or indicate that CP&L is committed to participate and implement recommended actions developed by industry-wide programs designed for determining the appropriate AMPs for the RNP RV bottom head instrumentation tubes made from Alloy 600.

RNP Response:

RNP is participating in industry-wide programs for nickel-based alloy penetrations. For example, in LRA Table 3.1-1, Item 23, RNP has proposed managing reactor vessel nozzles of the same material using a combination of the Nickel-Alloy Nozzles and Penetrations Program and Water Chemistry Program. The Nickel-Alloy Nozzles and Penetrations Program is a new program, which is described in Section B4.1 of the LRA. Subsection A.3.1.28, Nickel-Alloy Nozzles and Penetrations Program, of the LRA states the following:

> *"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."*** [Emphasis added.]

For additional information concerning the Nickel-Alloy Nozzles and Penetration Program, please refer to the RNP Response to RAI B4.1-1.

RAI 3.1.2.4.5-1

In AMR Items IV.A2.6-a of GALL, Volume 2, the staff identifies that crack initiation and growth due to PWSCC are applicable aging effects for Alloy 600 core support pads/core guide lugs and states that either a plant specific AMP is to be proposed to manage these effects or an applicant is to indicate that it will participate in industry-wide programs that will evaluate and determine the appropriate type of AMPs that will be used to manage crack initiation and growth in these components. Industry experience has demonstrated that PWSCC can occur in Alloy 600 components (e.g., steam generator tubes or CRDM penetration nozzles in PWRs) in spite of controlled maintenance of reactor coolant chemistry (e.g., PWSCC of steam generator tubes and CRDM nozzles). In AMR Item 9 of LRA Table 3.1-2, CP&L has proposed to manage crack initiation and growth in the Alloy 600 core support pads using the chemistry control program. The staff is concerned that chemistry control programs by themselves may not be capable of managing PWSCC-induced crack initiation and growth in the Alloy 600 core support pads since PWSCC may occur in Alloy 600 components even when the impurity levels of reactor coolant have been maintained within the recommended limits cited in industry standards or guidelines. The staff requests that CP&L either propose an inspection-based program that will be used in conjunction with the chemistry program to manage PWSCC-induced crack initiation and growth in the RNP Alloy 600 core support pads or to provide a commitment to participate and implement recommended actions developed by industry-wide programs that are designed to determine the appropriate AMPs for managing crack initiation and growth in the RNP RV core support pads.

RNP Response:

RNP will remain active in industry groups (e.g., see the RNP Response to RAI 3.1.2.4.4-1) to stay aware of new industry recommendations regarding inspections of core support pads. New developments and recommendations in this area will be reviewed for applicability to RNP, and will add or modify AMPs, as appropriate. This action will be in addition to the existing reliance on the Water Chemistry Program.

RAI 3.1.2.4.5-2

In AMR Item 16 of LRA Table 3.1-2, CP&L credited only the Chemistry Control Program with managing SCC in the RNP RV neutron flux thimble tubes. The RNP RV neutron flux thimble tubes are fabricated from Alloy 600 materials. Over the last three years, the PWR industry has had two significant events in nickel-based alloy weld materials. The first of these occurred in October 2000, at the V. C. Summer nuclear plant in which a through-wall PWSCC-induced crack was identified in the plant's Alloy 182/82 RV hot leg nozzle safe-end weld. The second of these occurred in March 2002 at the Davis Besse nuclear plant, in which a through-wall PWSCC-induced crack occurred in one of the plant's control rod drive mechanism (CRDM) nozzle Alloy 182/82 attachment welds. The cracking at Davis Besse is significant in that it lead to significant leakage of the reactor coolant from the RCS and to significant corrosive attack (i.e., boric acid-induced wastage) of the RV head in the vicinity of the degraded CRDM nozzle.

The staff is concerned that Water Chemistry Program alone may not be sufficient to prevent cracking in internal surfaces of nickel-based alloy components of the reactor coolant pressure boundary since PWSCC may occur in these components even when the impurity concentrations for oxygen and aggressive anions in the borated reactor coolant are controlled to acceptable levels. The events at V. C. Summer and Davis Besse confirm this. Provide your technical basis why the water chemistry program alone is considered to be sufficient to manage PWSCC in the RV neutron flux thimble tubes without the need for confirmation using an inspection-based program that will detect for PWSCC-induced cracking in the components. Consistent with the AMPs recommended in commodity group Item IV.B2.6-b of GALL, Volume 2, the staff's position is that both GALL AMP XI.M16, "PWR Vessel Internals Program," and GALL AMP XI.M2, "Water Chemistry Program," be credited with managing crack initiation and growth due to SCC/PWSCC/IASCC in the RNP RV neutron flux thimble tubes.

RNP Response:

The RNP flux thimble guide tubes are fabricated from stainless steel. The flux thimble guide tubes, equivalent to GALL Item IV.B2.6.1 in Volume 2 (GALL Items IV.B2.6-a and IV.B2.6-b), are part of the group of components evaluated in LRA Table 3.1-1, Item 33. This AMR item manages cracking due to various forms of SCC with the Water Chemistry Program and the PWR Vessel Internals Program. Therefore, RNP is consistent with GALL. LRA Table 3.1-2, Item 16, is used for the evaluation of the Reactor Vessel Internals Flux Thimbles. This item is equivalent to GALL Item IV.B2.6.2 in Volume 2 (GALL Item IV.B2.6-c). Cracking due to SCC is not identified in the GALL as an applicable aging effect.

Therefore, the Water Chemistry Program is an appropriate method for managing the aging effects associated with the flux thimble guide tubes.

RAI 3.1.2.4.6-1

In AMR Item 3 of Table 3.1-2 (LRA Page 3.1-32), CP&L identified loss of material from crevice corrosion as an aging effect for the steam generator (SG) anti-vibration bars. Industry experience has shown that loss of material at anti-vibration bars are caused predominantly by fretting and wear (metal to metal contact) rather than by crevice corrosion. Discuss why crevice corrosion was identified rather than fretting and wear for this Item.

RNP Response:

The RNP LRA identified "Loss of Material from Fretting" as an aging effect for the anti-vibration bars. The applicable aging effects identified for the anti-vibration bars are shown in Item 3 of LRA Table 3.1-2 (page 3.1-32) and are as follows:

- Cracking from SCC
- Loss of Material from Crevice Corrosion
- Loss of Material from Fretting

In determining whether or not an aging effect is applicable, RNP did not credit the beneficial effect of controlled water chemistry. This conservative assumption resulted in the identification of SCC and crevice corrosion as aging mechanisms for the anti-vibration bars. As stated on page 3.0-2 of the RNP LRA:

> *"The aging management review methodology for RNP did not credit the effects of aging management programs when determining if an aging effect requiring management may be applicable. The potential aging effects were evaluated assuming that any applicable aging management programs were not in effect. No credit was taken for coatings and linings, cathodic protection systems, corrosion inhibitors, biocides, inspections or other programs during the aging management reviews, because the entire set of aging effects requiring management may not be identified if these programs were credited a priori."*

RAI 3.1.2.4.6-2

In AMR Item 4 of LRA Table 3.1-2 (LRA Page 3.1-36), CP&L identified the water chemistry program as the only AMP to manage the aging effect of stress corrosion cracking and loss of material due to pitting/crevice corrosion in the RNP steam generator (SG) feedwater nozzle thermal sleeve safe ends and steam flow limiters. The staff is concerned about whether the chemistry control programs are sufficient to manage loss of material and cracking in RCS components without the need for use of a confirmatory inspection-based AMP to verify that the water chemistry program is achieving its preventative/mitigative purposes. The staff seeks clarification and justification why the applicant considers that the water chemistry program by itself will be sufficient to manage loss of material and cracking in the surfaces of the SG feedwater nozzle thermal sleeve safe ends and steam flow limiters, without the need for confirmation using an inspection based program, such as the steam generator tube integrity program or the ISI program, to verify that the water chemistry program is achieving its preventative/mitigative purposes for managing loss of material and cracking in these components. This generic RAI is also applicable to the management of aging effects in the following SG components:

a. Loss of material due to general, pitting, and/or crevice corrosion in the SG feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetration nozzles, and SG tube bundle wrappers and tubeplates under exposure to treated water environments (AMR Item 5 of LRA Table 3.1-2).

b. Loss of material due to erosion in the SG tube bundle wrappers and SG tubeplates that are fabricated from carbon steel and the steam flow limiters that are made of nickel-based alloy under exposure to treated water environments (AMR Item 6 of LRA Table 3.1-2).

c. Cracking due to stress corrosion cracking (SCC) as the aging effect for SG lower head divider plates and tubeplate cladding that are fabricated of nickel-based alloy under treated water and steam environment (AMR Item 11 of LRA Table 3.1-2).

RNP Response:

The steam generator tubeplate is fabricated from carbon steel with a nickel-based alloy cladding. The applicable AMRs for the carbon steel tubeplate are LRA Table 3.1-1, Item 1 (cumulative fatigue damage, which is a TLAA evaluated in accordance with 10 CFR 54.21(c)), LRA Table 3.1-2, Item 5 (loss of material from crevice, general, or pitting corrosion managed by the Water Chemistry Program), and LRA Table 3.1-2, Item 6 (loss of material from erosion managed by the Water Chemistry Program).

LRA Table 3.1-2, Item 11, is an evaluation of components fabricated from nickel-based alloys in a treated water environment. The components evaluated in the AMR item are the steam generator tubeplate cladding and steam generator lower head divider plate. The applicable aging effect is cracking from SCC, which is managed by the Water Chemistry Program.

The steam generator lower head (GALL, Volume 2, Item IV.D1.1.8 (IV.D1.1-g)) is fabricated from carbon steel with stainless steel cladding. The carbon steel head and its stainless steel cladding are evaluated separately in the LRA.

The carbon steel lower head is exposed to environments of containment air and borated water leakage. Since the lower head is internally clad, the carbon steel base material is not exposed to an environment of treated water. The applicable AMRs for the carbon steel lower head are LRA Table 3.1-1, Item 1 (cumulative fatigue damage, which is a TLAA evaluated in accordance with 10 CFR 54.21(c)) and LRA Table 3.1-1, Item 26, (loss of material due to boric acid corrosion which is managed by the Boric Acid Corrosion Program).

The stainless steel cladding is exposed to an environment of treated water. The applicable AMRs for the lower head cladding are LRA Table 3.1-1, Item 1, (cumulative fatigue damage, which is a TLAA evaluated in accordance with 10 CFR 54.21(c)), LRA Table 3.1-1, Item 32, (crack initiation and growth due to SCC, PWSCC, IASCC which is managed by the ISI and the Water Chemistry Program), and LRA Table 3.1-2, Item 2 (loss of material from crevice or pitting corrosion, which is managed by the Water Chemistry Program).

The adequacy of managing these aging effects by the use of the Water Chemistry Program has been previously accepted by the NRC and is consistent with industry practice. A discussion of the efficacy of the Water Chemistry Program to manage these aging effects is contained in the RNP Response to RAI 3.4.1-10. In addition, the One-Time Inspection Program (see page B-77 of the RNP LRA) includes "miscellaneous piping inspection to demonstrate water chemistry effectiveness" for systems connected upstream of the steam generators (such as the feedwater and AFW systems).

RAI 3.1.2.4.6-3

CP&L has identified that loss of mechanical closure integrity due to aggressive corrosive attack is an applicable effect for the RNP secondary side manway and handhole bolting components and credited the boric acid corrosion program as the AMP for managing this aging effect in the bolts. Section IV.D2.1-k of GALL Volume 2 identifies that loss of mechanical closure integrity due to stress relaxation (i.e., loss of preload) is also an applicable aging effect for the secondary side manway and handhole bolting components and states that the Bolting Integrity Program (GALL Program XI.M18) should be used to manage loss of preload in these bolts. Provide your technical basis for concluding that loss of preload is not an applicable aging effect for the SG secondary side manway and handhole bolting components. If loss of preload is an applicable aging effect for the SG secondary side manway and handhole bolting components amend your AMR for these components (AMR Item 12 of Table 3.1-2 to the LRA) to include loss of mechanical closure integrity due to stress relaxation (i.e., loss of preload) as an applicable aging effect for the components, and to include the Bolting Integrity Program as the AMP for managing loss of preload in the SG secondary side manway and handhole bolting components.

RNP Response:

Please refer to the RNP Response to RAI 3.1.2.1-3.

RAI 3.1.2.4.6-4

In the discussion Section of AMR Item 12 of Table 3.1-2 of the LRA, CP&L concludes that stress corrosion cracking (SCC) is not an applicable aging effect for the SG secondary side manway and handhole bolting materials because the minimum yield strength for the bolting materials was less than 150 ksi. The staff needs to emphasize that minimum yield strength refers to a minimum acceptance criteria for the yield strength of a given material (which is a material property) and does not refer to the yield strengths for the materials themselves. The staff has used 150 ksi as the threshold for initiation of SCC in for high strength bolting materials (such as martensitic stainless steel grades or precipitation hardened stainless steel grades). The staff considers that SCC will not be an applicable aging effect for high strength bolting materials if the yield strengths for the materials are confirmed to be lower than 150 ksi or the hardness values for the materials are confirmed to be less than a value of 32 on a Rockwell-C hardness scale. In order to take credit that the SCC is not an applicable aging effect for the SG secondary side manway and handhole bolting materials, confirm that either the yield strengths or Rockwell-C hardness values for the SG secondary manway and handhole bolting materials are within the specified acceptable range for the corresponding material property.

RNP Response:

The RNP SG secondary manway and handhold bolting is SA-193 Grade B7.

A survey of industry experience, technical literature, and laboratory corrosion studies (EPRI NP-5769, Volume 2, Figure 11B-1 and NUREG-1339) indicates that SCC should not be a concern for closure bolting in nuclear power plant applications if the specified minimum yield strength is <150 ksi.

For low alloy, quenched and tempered (LAQT) stainless steel typically used for closure bolting (e.g., SA-193 Grade B7), susceptibility to SCC is controlled by yield strength and hardness limits. The minimum yield strength specified in SA-193 for Grade B7 material is 105 ksi. The maximum Brinell hardness is 321, which limits the yield strength to approximately 140 ksi (<150 ksi threshold for SCC susceptibility). This is based upon industry test results that correlate yield strength as a function of hardness.

Therefore, cracking due to SCC is not considered to be an aging effect requiring management for the SG secondary manway and handhold bolting.

RAI 3.1.2.4.6-5

Explain why the snubber components, which are active components, are included within the scope of AMR Item 7 of LRA Table. 3.1-2.

RNP Response:

RNP has conservatively included the passive portions of the reservoir components within the scope of license renewal.

Page 2.3-8 of the RNP LRA states:

> *"The steam generator support system includes hydraulic snubbers. The snubbers are considered to be structural components; however, portions of the hydraulic equipment for each steam generator (manifold, hydraulic control unit, flex hoses, piping, reservoir) are subject to an aging management review to assure their pressure boundary integrity is maintained."*

RAI 3.1.2.4.6-6

Provide a detailed description of the in-scope steam generator (SG) snubber reservoir components within the scope of AMR Item 7 of LRA Table. 3.1-2.

RNP Response:

Page 2.3-8 of the RNP LRA states:

> *"The steam generator support system includes hydraulic snubbers. The snubbers are considered to be structural components; however, portions of the hydraulic equipment for each steam generator (manifold, hydraulic control unit, flex hoses, piping, reservoir) are subject to an aging management review to assure their pressure boundary integrity is maintained."*

RAI 3.1.2.4.6-7

Explain how the plant-specific preventative maintenance program manages the aging effects that have been identified for the snubber reservoir components within the scope of AMR Item 7 of LRA Table 3.1-2.

RNP Response:

Section B.3.18 of the RNP LRA provides a description of the overall Preventive Maintenance Program. These specific components are subject to visual inspection to detect leakage and physical condition at a frequency not to exceed 18 months, and the components are replaced as required.

RAI 3.2.1-1

In LRA Table 3.2-1, Item No. 2, under Discussion, the applicant states that the RNP AMR methodology **assumed** that, for containment isolation system, external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The staff found the above statement on environments to lack affirmation. The applicant is, therefore, requested to ascertain the plant-specific environments, based on which the applicant stated that RNP equipment in this component/commodity group is not subject to general corrosion.

RNP Response:

The RNP AMR methodology concluded that external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The external surfaces of the carbon steel components that are included in LRA Table 3.2-1 item2 and Item 6 were determined to be subjected to an environment meeting the following conditions: air-gas, not subjected to condensation or aggressive chemical attack, and protected from weather.

If carbon steel components are not exposed to weather, not prone to condensation, and not subject to boric acid leakage, they will experience insignificant amounts of corrosion. The external environment being referred to is typical of ambient air, e.g., under a shelter, indoors or air conditioned enclosure or room. Significant amounts of corrosion of carbon steel require an electrolytic environment. Hence, the RNP methodology determined that no aging effects were applicable to this category. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes corrosion product buildup. At ordinary temperatures and in neutral or near neutral media, oxygen and moisture are the factors that affect the corrosion of iron. Both oxygen and moisture must be present because oxygen alone or water free of dissolved oxygen does not corrode iron to any practical extent. Carbon and low-alloy steels as well as cast iron are susceptible to general corrosion, whereas stainless steels, nickel-based alloys, aluminum, copper and copper alloys, and galvanized steel are resistant to general corrosion.

Moisture in the form of liquids and alternate wetting and drying is necessary for significant pitting and crevice corrosion in an ambient air environment. The humid environments under discussion are indoors but even if they were sheltered in the Turbine Building and not exposed to alternate wetting or drying and not subject to condensation the same conclusions would be valid.

The previous discussions regarding aging mechanisms in external ambient environment are supported by relevant industry experience.

RAI 3.2.1-2

In LRA Table 3.2-1, Item No. 6, for external surface of carbon steel components, and in Table 3.2-2, Item No. 14, for carbon steel valves, piping and fittings, the applicant applied the same AMR argument as stated in RAI 3.2.1-1, for excluding the consideration of material susceptibility to corrosion. The applicant is requested to provide similar additional information as requested in RAI 3.2.1-1.

RNP Response:

See the RNP Response to RAI 3.2.1-1 regarding the bases.

RAI 3.2.1-3

In LRA Table 3.2-1, Item No. 3, the applicant stated that pitting and crevice corrosion are not a creditable aging mechanism for the exterior bottom of the stainless steel refueling water storage tank, in part, because the tank bottom sits on a layer of oiled sand. The applicant is requested to discuss the merit of having the tank sitting on a layer of oiled sand, including the type of oil used and the need for a oil chemistry monitoring.

RNP Response:

The RWST foundation drawing shows a 6 inch layer of oiled sand separating the tank bottom from compacted earth.

A review of related industry documents confirms that past practice has been to use an oiled sand cushion under the tank in order to reduce bottom side corrosion.

The RNP evaluation for stainless steel requires water intrusion for crevice corrosion or pitting corrosion to occur (in either oil or damp soil). As stated in LRA Table 3.2-1, Item 3 (Discussion), pitting and crevice corrosion are not credible aging mechanisms for the exterior bottom of the RWST. The reasons cited were (1) the tank location is well above the groundwater elevation, (2) the area around the tank is well drained, and (3) the tank bottom sits on a layer of oiled sand. RNP has reviewed the supporting AMR evaluation and determined that the presence of oil in the sand below the tank does not prevent, mitigate, nor contribute to age-related degradation such as crevice and pitting corrosion. For these aging effects to occur in stainless steel, the RNP AMR evaluation requires the presence of an electrolyte (water contamination). The bottom of the RWST is above grade and well above the groundwater elevation. Also, flooding is not postulated at the plant (see UFSAR Section 2.4.1.1). Therefore, RNP does not consider crevice or pitting corrosion to be credible aging mechanisms for the exterior surface of the RWST (including the tank bottom) and assumes no credit for the oiled sand layer in making this determination.

RAI 3.2.1-4

LRA Table 2.3-3 lists component/commodity groups requiring aging management review for the containment spray (CS) system, whereas Table 2.3-4 lists those for the safety injection (SI) system. For closure bolting, Table 2.3-4 provides links to Table 3.2-1, Item Nos. 6 and 11, which address corrosion due to aggressive chemical attack resulting from leakage of NaOH and leakage of boric acid solution, respectively. Table 2.3-3, on the other hand, provides links to Table 3.2-1, Item No. 11, and Table 3.1-1, Item No. 26, which address closure bolting in the reactor coolant system (RCS). The applicant is requested to explain why, for closure bolting in the safety injection system, Table 3.1-1, Item No. 26, is referenced in Table 2.3-3, but not Table 3.2-1, Item No. 6. The applicant is also requested to discuss how AMR is performed for closure bolting located in RCS, SI and CS systems, and explain the interface among the three systems. Finally, the applicant is requested to substantiate that all the potential aging effects requiring management for the closure bolting are identified and adequately managed.

RNP Response:

Portions of the RNP SI system include components that implement the CSS function. These components collectively are described in the LRA as the CSS. This can be seen on the flow diagrams for the SI system, 5379-1082LR. Therefore, components/commodities subject to an aging management review may be listed on either LRA Table 2.3-3 or LRA Table 2.3-4, and the results of the AMR are included in LRA Tables 3.2-1 and 3.2-2. Since they do not directly connect to the reactor coolant system (RCS) piping, there are no ISI Class 1 components in the CSS. On the other hand, there is a portion of the SI system piping and valves (including closure bolting) that connects to the RCS piping and is classified as ISI Class 1. These interfaces can be seen on the flow diagrams for the SI system and RCS. These Class 1 components in the SI system were evaluated in the RCS AMR and the AMR results reported in LRA Tables 3.1-1 and 3.1-2. The RCS AMR defined closure bolting to include the affected RCS components and the interfacing systems components that are ISI Class 1, e.g., ISI Class 1 components having closure bolting in the RHR system, CVCS, and the SI system.

In LRA Table 2.3-3, the references for Closure Bolting in the SI system should also refer to Table 3.2-1, Item No. 6, which is supported by the SI system AMR. The reference to Table 3.1-1, Item 26, is inconsistent with the SI system AMR, which only applies to ISI Non-Class 1 components. Non-Class 1 components having closure bolting in the SI system and located in the Reactor Auxiliary Building are also potentially subject to aggressive chemical attack from NaOH. Therefore, Closure Bolting in LRA Table 2.3-3 should also include reference to LRA Table 3.2-1, Item 6. As noted above, the SI system includes components that perform the CSS function. The reference to LRA Table 3.2-1, Item 6, in LRA Table 2.3-3 was inadvertently omitted when RNP divided the SI system components between LRA Tables 2.3-3 and 2.3-4.

Closure bolting for the CS system is shown on LRA Table 2.3-4 and is subject to aggressive chemical attack from both boric acid (addressed in LRA Table 3.2-1, Item 11), and NaOH (addressed in LRA Table 3.2-1, Item 6). The spray additive tank, which contains the NaOH, is only associated with the CSS and is shown on LRA Table 2.3-4.

As noted above, the reference for Closure Bolting to Table 3.1-1, Item 26, in LRA Table 2.3-3 is inconsistent with the SI system AMR. The RCS AMR addresses closure bolting for the RCS system components and its interfacing system components that are ISI Class 1. Table 2.3-3 was meant to describe the results of the ISI Non-Class 1 components in the SI system. This anomaly occurred during sorting of the SI system component tags that were used to represent closure bolting in the LRA. Since bolting is a subcomponent at RNP, it has no tag number. The tag selected to represent closure bolting was one that is used for miscellaneous pipe in the SI system. This general tag in the equipment database is conservatively classified as ISI Class 1, but was evaluated in the SI system AMR. It should have been grouped as an RCS interfacing component and a different component used to represent ISI non-class 1 closure bolting.

The aging effects associated with closure bolting other than from aggressive chemical attack are discussed in RAI 3.1.2.1-3 for a specific case in RCS bolting, but can be expanded to understanding how other bolting applications were addressed. As noted in RAI 3.1.2.1-3, RNP has developed a bolting and torque program based on EPRI guidance to address many of the potential aging effects. The aging effect associated with thermal fatigue due to cycling is addressed by a TLAA. Other aspects such as cracking and wear are managed, in-part, by an ASME Code, Section XI, Inservice Inspection, IWB, IWC, and IWD Program. In this way, aging effects associated with bolting were address on a generic basis. Therefore the items described in this RAI (RAI 3.2.1-4) address only the aging effect associated with closure bolting from aggressive chemical attack.

RAI 3.2.1-5

Through LRA Table 2.3-4 and Table 3.2-1, Item Nos. 6 and 11, the applicant indicated that carbon steel components in the containment spray system may be subject to corrosion due to aggressive chemical attack. The applicant is requested to confirm that the containment spray system and its associated components, such as closure bolting, CV spray pump seal heat exchanger shell and cover, spray additive tank, valves, piping, tubing, and fittings, are properly included in the scope, and that adequate AMRs have been performed to ensure that all the relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs are identified and documented.

RNP Response:

The RNP Response to RAI 3.2.1-4 discusses the distribution of components in the SI system that perform the system intended functions to inject coolant into the RCS and spray coolant containing borated water and NaOH solution into containment. The SI system AMR for RNP addresses SI and CSS components as System 2080, SI system components. The results for the ISI Class 1 piping components in the SI system are evaluated in the RCS AMR and are, therefore, reported in LRA Tables 3.1-1 and 3.1-2. The results of the ISI Non-Class 1 piping components in the SI system are reported in the LRA Tables 3.2-1 and 3.2-2.

LRA Table 2.3-4, "Spray Additive Tank," should reference LRA Table 3.2-1, Item 6, and LRA Table 3.2-2, Item 1. The reference to LRA Table 3.2-1, Item 11 is incorrect for the Spray Additive Tank and its associated closure bolting, as there are no potential borated water leakage sources in the spray additive tank room. The Spray Additive Tank is a carbon steel tank with a stainless steel lining. Associated piping components are composed of stainless steel.

The valves, piping tubing and fittings in the SI system that required an AMR, except for those associated with the si accumulator nitrogen supply, are stainless steel. Therefore, reference to Table 3.2-1, Item 6, in LRA Table 2.3-4, is incorrect.

The CV spray pump seal heat exchanger shell and cover are made of carbon steel. Its external surface is subject to indoor air and potential leakage from aggressive chemical attack, e.g., boric acid (See Tables 3.2-1, Item 11). In addition, the SI system AMR was reviewed and is addressed and managed by the Boric Acid Corrosion Program. Its internal surface is subjected to water from the CCW system. The results are discussed in LRA Tables 3.2-1 and 3.2-2, as noted in LRA Table 2.3-4.

RAI 3.2.1-6

For the RHR system, LRA Table 3.2-1, Item No. 11, and Table 3.1-1, Item No. 26, are referenced in LRA Table 2.3-2 as links for closure bolting. The applicant is requested to clarify the boundary interface between the RCS system and the RHR system. The applicant is also requested to confirm that an adequate AMR has been performed for the closure bolting in the RHR system to ensure and that a relevant material/environment combination, the aging effect requiring management, and the corresponding aging management program are identified and documented.

RNP Response:

RAI 3.2.1-4 describes the boundary interface between RHR system and RCS and describes how closure bolting is addressed in the SI system. The same discussion applies to how closure bolting is addressed in the RHR system.

The closure bolting cross-reference to Table 3.1-1, Item No. 26, is incorrect in LRA Table 2.3-2. The AMR results for ISI Non-Class 1 components in the RHR system are in LRA Tables 3.2-1 and 3.2-2. The situation is analogous to RAI 3.2.1-4 related to SI system - the tag number, RHR-MISC-PIPE, which was used to represent ISI Non-Class 1closure bolting in the RHR system, is also classified as ISI Class 1.

The RHR system and RCS AMRs were reviewed, and it was confirmed that appropriate materials, environment, and aging effects were identified and appropriate programs were selected to manage the aging effects.

RAI 3.2.1-7

For the containment air recirculation system, LRA Table 3.3-1, Items No. 2, 5, 13, and 16, are referenced in LRA Table 2.3-5 as links for flexible collars, equipment frames and housings, closure bolting, valve, and heating/cooling coils. Since Table 3.3-1 addresses component/commodity groups in the auxiliary system (versus the engineered safety features systems), the applicant is requested to clarify, for the containment air recirculation system and the above associated components, that adequate AMRs have been performed to ensure that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs are identified and documented.

RNP Response:

AMRs have been performed for the containment air recirculation system, with the following aging management programs having been identified:

Containment Air Recirculation System (System 8150 - HVAC Containment Building System)		
Item	Component	Aging Management Programs
2	Flexible Collars	Systems Monitoring Program
5, 13	Equipment Frames And Housings	Preventive Maintenance Program; Boric Acid Corrosion Program
13	Closure Bolting	Boric Acid Corrosion Program
5, 16	Heating/Cooling Coils	Preventive Maintenance Program; Open-Cycle Cooling Water System Program

The AMR evaluated each of the Component/Commodity Groups by identifying the material and environment combinations that each might experience. Each Component/Commodity Group may be made up of several different tagged components, e.g., valves, ductwork. Each larger tagged component, such as an air handling unit may be evaluated as many component commodities, e.g., heating/cooling coils, equipment frames and housing, closure bolting. The line items in LRA Table 3.3-1 typically represent one or more Component/Commodity Group with one or more material environment combinations as determined by the corresponding table in GALL. The four Component/Commodity Groups that are subject of this RAI, "flexible collars", "equipment frames and housings", "closure bolting", and "heating/cooling coils," collectively represent a portion of the containment air handling units and associated ductwork. These Component/ Commodity Groups were evaluated based on commodity type (e.g., valve, flexible collar, and cooling coil) and their respective material and environment combinations. Since the Component/Commodity Groups are not all the same material and environment combinations, they have not been included in a single item, even though they may comprise the same air handling unit.

Based on the above discussion, the aging management review has appropriately considered these components and applied the appropriate programs to address the aging effects requiring management.

RAI 3.2.1-8

In LRA Table 2.3-6 and Table 3.2-1, Item Nos. 3 and 4, the applicant credited the preventive maintenance program for managing aging effects of loss of material due to pitting and crevice corrosion, MIC, and biofouling, for the stainless steel valves, piping, and fittings in raw water associated with containment penetrations. The staff noted that, in Appendix B.3.18, Preventive Maintenance Program, under "Monitoring and Trending", the applicant included "leaking and physical condition" as a parameter to be monitored and trended. It is the staff's understanding that the presence of fluid leakage would have already signaled components' failure to provide pressure-retaining boundary. The applicant is requested to clarify whether any of these components for which the preventive maintenance program is credited for managing the aging effects relies on the monitoring of fluid leakage. In addition, the applicant is requested to provide a discussion on the operating history of these components to demonstrate that the associated aging effects will be adequately managed prior to the components' loss of intended pressure-retaining function.

RNP Response:

Regarding the inclusion of leakage in the "Monitoring and Trending" element, refer to the discussion of leakage in the RNP Response to RAI 3.3-5.

A review of the operating history of the affected systems listed on LRA Table 2.3-6 (Liquid Waste Processing and Isolation Valve Seal Water Systems) found no occurrences of degradation attributable to the effects of aging.

RAI 3.3-1

Numerous ventilation systems including reactor auxiliary building HVAC, control room area HVAC, fuel handling building HVAC systems, the containment purge system, and rod drive cooling discussed in Section 2.3 of LRA include elastomer components in the system. Normally these systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In Table 3.3-1, Row Number 2 of the LRA, the applicant identified the aging effects of hardening, cracks, and loss of strength due to elastomer degradation and credited the System Monitoring Program for managing these aging effects. In the "Discussion" column of that row , the applicant stated that loss of material due to wear was not identified as an aging mechanism for these elastomer components; however, wear also would be managed by the System Monitoring Program. The staff noted that the description of this program, AMP B.3.17, did not include wear as one of the aging mechanisms of concern. Please clarify the discrepancy between Table 3.3-1, Row Number 2 and Section B.3.17 regarding the aging effects/mechanisms of concern. In addition, please provide the frequency of the subject inspection described in Section B.3.17 for the applicable elastomer components including a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior the loss of their intended function.

RNP Response:

As stated in the discussion for LRA Table 3.3-1, Row 2, "wear" was not identified as an aging effect for these components, however, the RNP aging management program will be enhanced to ensure "Loss of Material due to Wear" is specifically included as an aging effect/mechanism identified in the system walkdown checklist. This will ensure that this effect/mechanism will be managed consistent with GALL VII.F1.1-c, VII.F2.1-c, VII.F3.1-c, and VII.F4.1-c.

Walkdowns are typically scheduled and performed so the entire system is fully walked down within one operating cycle.

The Systems Monitoring Program is designed to detect aging effects prior to structure or component failure. As an example, system walkdowns identified degradation of flexible connections between the fan unit housing for the containment recirculating cooling units and the adjacent ductwork. This degradation was characterized by missing/torn flexible material. For this degradation, the material was replaced by a different material. This example demonstrates the effectiveness of the current site program in identifying degradation prior to loss of component intended function. Implementation of program enhancements identified during the license renewal process will serve to further increase program effectiveness. The enhancements are generally described in LRA B.3.17.

A more detailed description of several of the relevant program attributes is discussed in the RNP Response to RAI B.3.17-1.

RAI 3.3-2

For the closure bolting in several of the auxiliary systems included in Table 3.3-1, Row Number 13 of the LRA, the applicant identified loss of material due to boric acid corrosion as an applicable aging effect. In the "Discussion" column of that row, the applicant stated that loss of material due to boric acid corrosion can lead to loss of mechanical closure integrity of closure bolting. The applicant also stated that the aging mechanism is loss of mechanical closure integrity from loss of material due to aggressive chemical attack. The applicant credited the Boric Acid Corrosion Program (AMP B.3.2) for managing this aging effect. The staff also noted that in Table 3.3-1, Row Number 23 of the LRA, the applicant has identified loss of material due to general corrosion: crack initiation and growth due to cyclic loading and SCC as the applicable aging effects for closure bolting in auxiliary systems. The applicant credited the Bolting Integrity Program (AMP B.3.4) for managing these aging effects. However, the staff noted that, with the exception of closure bolting in CVCS , the applicant did not identify these aging effects included in Table 3.3-1, Row Number 23 for the closure bolting in auxiliary systems. Please explain why the other aging effects/mechanisms of concern identified in AMP B.3.4 and Row Number 23 of Table 3.3-1 are not applicable to the closure bolting in other auxiliary systems and why the Bolting Integrity Program (AMP B.3.4) is not being used to manage aging effects for the closure bolting in these auxiliary systems.

RNP Response:

The RNP methodology treats pressure boundary bolting as a subcomponent; except in those cases where it must be individually evaluated for aging management review. If a valve and its pressure boundary bolting are considered susceptible to an aging effect, and the same aging management program would be applied to both, then the bolting would generally be treated as part of the valve. Within this constraint, the listing of aging effects in AMP B.3.4 is an aggregate set applicable to bolting in the scope of license renewal.

Relative to Table 3.3-1, Row 23 (Aux. System Closure Bolting), aging management of bolting for SCC was specified only in those instances where susceptible bolting was identified. SCC of bolting requires susceptible material (generally associated with bolts with minimum yield > 150 ksi), and a design review found a single incidence of susceptible auxiliary system pressure boundary bolting in the scope of license renewal. This resulted in the listing of SCC of bolting in Table 3.3-1, Row 23, and AMP B.3.4, noted in the RAI.

In addition to boric acid wastage (Table 3.3-1, line 13) and SCC (Table 3.3-1, line 23), the Bolting AMP description in B.3.4 identifies stress relaxation and wear as applicable aging effects. The instance of stress relaxation noted in AMP B.3.4 is based on site operating experience and is specific to the reactor coolant pump flanges. Stress relaxation has been evaluated to be not applicable to RNP auxiliary systems based on system operating temperatures, and loss of pre-load is considered to be a design issue, not an aging effect. Similarly, the potential for wear was based on a review of Generic Technical Report WCAP-14575-A regarding RCS Class 1 closures, and is not considered applicable to auxiliary systems. Hence, neither of these aging effects was included in LRA Table 3.3-1.

RAI 3.3-3

In Table 3.3-2, Row Number 19 of the LRA, the applicant did not identify aging effects for carbon steel externally exposed to indoor - not air conditioned, containment air, and air-gas environments. In the "Discussion" column of that row, the applicant stated that its AMR methodology assumed that external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage)." Please verify this assumption is appropriate for the combination of material and environments listed in Table 3.3-2, Row Number 19 of the LRA.

RNP Response:

LRA Table 3.3-2, Row Number 19 represents carbon steel components that are indoors, not exposed to weather, not prone to condensation, and therefore are not considered to be in a moist environment. In the absence of an aggressive chemical environment (i.e., boric acid leakage), significant corrosion of carbon steel will not occur without the presence of moisture. Hence, the RNP methodology determined that no aging effects were applicable to this category. See the RNP Response to RAI 3.2.1-1 for additional information in this regard.

RAI 3.3-4

In Table 3.3-2, Row Number 20 of the LRA, the applicant did not identify aging effect for galvanized steel externally exposed to borated water leakage. In the "Discussion" column of that row, the applicant stated that its AMR methodology determined these galvanized steel components would experience no age related degradation requiring management in this environment. This determination may not be supported by the industry experience. Similar to carbon steel and other low-alloy steel, galvanized steel components exposed to boric water leakage may be susceptible to boric acid corrosion. Please provide basis for not considering boric acid corrosion as an applicable aging effect for these galvanized steel components included in Table 3.3-1, Row Number 20.

RNP Response:

The aging effects and aging management reviews applicable to galvanized steel components exposed to borated water leakage were reviewed. Based on the potential for boric acid leakage to concentrate to the point where degradation of the galvanized steel coating could occur, it was determined that galvanized steel components would be as susceptible to aging effects from boric acid leakage as carbon or low alloy steels.

For those galvanized steel components exposed to boric acid leakage, the aging effect was changed to "loss of material;" the corresponding mechanism was changed to "Aggressive Chemical Attack." The Boric Acid Corrosion Program will be used to manage loss of material due to aggressive chemical attack for the external surfaces of such components.

RAI 3.3-5

In Table 3.3-1, Row Number 5 of the LRA, the applicant credited the Preventive Maintenance Program for managing aging effects for the internal surfaces of numerous components in auxiliary systems. The staff noted that in Appendix B.3.18, Preventive Maintenance Program, under "Monitoring and Trending," the applicant included leakage as an example of technique and parameter monitored. The presence of leakage from a component; however, would indicate that the component could not perform its intended function as a pressure boundary. Please clarify whether any of these auxiliary systems components for which the Preventive Maintenance Program is credited may rely on the monitoring of leakage. In addition, please provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions.

RNP Response:

Expected leakage from systems typically consists of flange or packing leaks. Through-wall leaks are not expected and would require corrective action, not trending. During preventive maintenance activities, equipment is opened and is externally and internally inspected for degradation. Many of the repetitive preventive maintenance procedures and work packages require general surface conditions to be inspected. Leakage represents an extreme point of degradation and would not typically be relied upon as the sole attribute of the monitoring program.

Some examples of Monitoring Techniques/Trend Parameters for various plant equipment types are:

- Helium leak detection: main condenser tubes, various valves and flanges
- Plant walkdown: Look for various performance problems, such as dump valves not reset, steam trap leaks, valve leak-through to the condenser, miscellaneous steam leaks, oscillating feedwater level control, etc.
- Visual Examinations: Coating failures, corrosion, cracking, erosion, leaking and physical condition, mechanical damage, loose or missing hardware, etc.

For many of these trended parameters, specific acceptance criteria would need to be established and basis developed depending on the condition found. For example, the outer surfaces of HVAC cooling coils are inspected for condition (e.g., corrosion, leakage, and fouling). Leakage is not the sole parameter monitored, but might indicate cracking or degradation. The result may be more careful or frequent inspections. Also, leakage would be an indication that additional and more directed inspections may be needed to ascertain the extent of condition. Industry and site experience indicates that leakage cannot always be accurately predicted, and that leakage does not necessarily mean that the system intended function cannot be achieved.

RAI 3.3.2-1

Table 2.3-21, closure bolting, cites Table 3.3-1, Item 13, for flow orifices, valves, piping and fittings. This Item is credited for managing loss of material due to boric acid corrosion of carbon steel. Clarify whether this is due to the fire protection system proximity to systems containing boric acid. If not, provide the basis for citing Table 3.3-1, Item 13 for managing aging.

RNP Response:

The reference to closure bolting applies to bolting material in piping systems where boric acid wastage is a potential aging effect. The fire protection system has bolted components in the proximity of systems containing boric acid in locations in the Auxiliary and Containment Buildings.

RAI 3.3.2-2

Table 2.3-21, Component/Commodity Groups Requiring Aging Management Review and Their Functions: Fire Protection System, Item 3 - Fire Hydrants, cites Aging Management Report Table 3.3-1, item 5. Item 5 discusses ventilation, diesel fuel and emergency diesel generator aging of carbon steel. Fire hydrants are not included in item 5 on Table 3.3-1 and are typically cast iron and not carbon steel. Provide the basis for citing Table 3.3-1 Item 5 for aging of fire hydrants.

RNP Response:

The RNP aging management review methodology, developed for identifying applicable aging effects, addressed those items containing cast iron within the context of the "Carbon Steel" material group. Fire hydrants were evaluated as cast iron components for determination of aging effects associated with a raw water (internal) environment, consistent with GALL, Section VII.G.6.2 (see Table 3.3-1, Item 20, of the RNP LRA). GALL does not include a line item corresponding specifically to water based fire protection components in an outdoor environment. Fire hydrants were included in a carbon steel / air component grouping corresponding to GALL Section VII.I.1-b, for consideration of external aging effects (LRA Table 3.3-1, Item 5, as noted above).

RAI 3.3.4-6

In Row Number 14 of LRA Table 3.3-1, the applicant identified the loss of material from crevice corrosion, general corrosion, and pitting corrosion as aging effect/mechanism for carbon steel and stainless steel components in treated water environment in the Chemical and Volume Control System (CVCS). The applicant further indicated that the applicable AMP is the RNP's "Close-Cycle Cooling Water System Program" (AMP B.2.5). The staff reviewed the AMP B.2.5 and found that CVCS is not covered by the AMP B.2.5. Similarly, Row Number 8 of Table 3.3-1 for heat exchangers in CVCS is not covered by the RNP AMP B.2.5. Please explain these discrepancies.

RNP Response:

In addition to the systems listed in AMP B.2.5, the Closed-Cycle Cooling Water System Program is credited for managing aging effects for components interfacing with the CCW system. This includes components in the RHR system, SI system, and CVCS, which are cooled by the CCW system.

RAI 3.3.4-7

In LRA Table 2.3-10 for CVCS, the applicant did not identify Row Number 4 of the LRA Table 3.3-1 as an Item in AMR results for charging pump in CVCS. The applicant described its bases for excluding the aging effect of cracking in the "Discussion" column of Table 3.3-1, Row Number 4. The applicant is requested to provide operating experience to support the stated bases for excluding the cracking due to SCC in the RNP CVCS charging pump.

RNP Response:

RNP reviewed industry and plant specific operating experience to support and validate the AMR methodology and the resulting aging effects/mechanisms. The general methodology is described in LRA Section 3.3.1.2 for Auxiliary Systems.

Although GALL does identify “cracking” as an applicable aging effect for the high-pressure pump casing, the RNP LR review of industry operating experience has identified only one case of cracking in a charging pump casing. This case was identified in NRC IN 80-38, “Cracking in Charging Pump Casing Cladding.” This cracking was specific to a different type of charging pump manufactured by the Pacific Pumps Division of Dresser Industries. These pumps were carbon steel with stainless steel cladding welded to the inner surface, and the cracking was in the weld and was attributed to high-cycle vibration. The RNP CVCS uses Union reciprocating type pumps with stainless steel casings. Therefore, this aging effect was deemed not applicable as a result of the OE review.

At RNP, cracking was identified in the “C” charging pump bore hole. This was caused by high hoop-stresses in the cylinder wall due to improperly fitted cylinder inserts. The maintenance practices were changed to use more exacting tolerances. This failure was therefore not considered an aging concern for properly maintained charging pumps.

No other instances of cracking were identified in the OE review.

As stated in LRA Table 3.3-1, Item 4, a temperature criterion of >140°F is used as the threshold for susceptibility of austenitic stainless steels to SCC. This is based upon industry experience and industry guidance. The RNP AMR includes a review of industry and site operating experience. No instances were identified that would bring this temperature threshold into question.

RAI 3.3.5-8

In Table 3.3.1, Row Number 18, the applicant stated that the components in the instrument air system at Robinson contains clean, dried air. The applicant also stated that the aging mechanisms in the GALL Report are not applicable to RNP instrument air system because moisture is controlled. It should be noted that in the instrument air system, components that are located upstream of the air dryers are generally exposed to wet air/gas environment and, therefore, may be subjected to aging effect of loss of material due to general and pitting corrosion. In addition, it is reasonable to assume that components downstream of the dryers are exposed to dry air/gas environment. However, this may not be supported by the operating experience. For an example, NRC IN 87-28, "Air Systems Problems at U.S. Light Water Reactors," provides the following: "A loss of decay heat removal and significant primary system heat up at Palisades in 1978 and 1981 were caused by water in the air system." This experience implies that the air/gas system downstream of the dryer may not be dry. Please provide technical basis for not identifying loss of material as an aging effect for these components including a discussion of the plant specific operating experience related to components that are exposed to instrument air environment to support your conclusion.

RNP Response:

Associated with the RNP IA compressors are Atlas Copco adsorption type desiccant dryers, both capable of producing dry air with a dew point less than 0°F. The dryer operates with continuous regeneration, utilizing air that bypassed the compressor after-cooler. This air is still hot and unsaturated and is used to regenerate the drum by evaporating the moisture adsorbed through the drying process.

The desiccant dryer is efficient in removing moisture and is capable of design dew points of less than 0°F. The lower dew point for compressed air will prevent condensation and buildup of foreign material in air operated valves.

Dry air is provided by the instrument air system by design of the compressors and air dryers. Dry air quality is maintained during operation by a program of preventive and post-maintenance testing and operator actions. Dry air quality is demonstrated by the trouble free operation of the downstream instruments and components, as indicated by plant operating experience discussed below.

Quarterly testing is performed quarterly to verify instrument air dew point using preventive maintenance procedures, and is also performed after maintenance on the air dryers using post maintenance testing procedures. The instrument air dew point is verified to be less than 0°F by measurement at four locations in the IA system.

Operations personnel verify on a shiftly basis that the IA receivers contain dry air.

Operating experience since the installation of the "D" high capacity IA compressor was examined to identify potential negative trends with respect to IA quality.

Work orders for the IA filters downstream of the air receivers and upstream of the main steam isolation valves, and upstream of the main steam power operated relief valves were reviewed to identify potential occurrences of problems that might be associated with poor air quality, such as moisture. No such occurrences were identified. Work orders for a representative sample of downstream components were reviewed, and no occurrences were identified of problems that might be associated with poor IA quality.

Loss of material was not identified as an aging effect for IA components subject to AMR based on the dry air delivered by the IA system downstream of the air dryers. Dry air is provided by system design, and is maintained by system operation and testing requirements. Dry air is further demonstrated by a review of plant specific operating experience related to components that are exposed to the IA environment.

RAI 3.3.6-9

In Row Number 23 of LRA Table 3.3.-2 the applicant identified "Flow Orifices" as one of the Component Commodity. However, Table 2.3-12 did not identify Row Number 23 of Table 3.3-2 under flow orifices. Please clarify this discrepancy.

RNP Response:

LRA Table 3.3-2, Item 23, deals with components fabricated from stainless steel. The nitrogen supply/blanketing system flow orifices/elements are carbon steel. Therefore, Item 23 of LRA Table 3.3-2 was not identified as an applicable reference.

RAI 3.3.8-10

Table 2.3-14 of LRA referred to Row Number 5 of Table 3.3-1 for AMR results. However, Item 5 of Table 3.3-1did not include Primary and Demineralized Water System under the Component /Commodity Group (column (1)). Please clarify this discrepancy.

RNP Response:

LRA Table 3.3-1, Item 5, deals with several categories of components, including external surfaces of carbon steel components. The external surfaces of carbon steel components in the primary and demineralized water system have been included here.

RAI 3.4.1-1

Industry operating experience has identified cracking from mechanical vibration as a potential aging effect for the piping system components in the steam and power conversion systems. Given this experience, please explain why mechanical vibration is not identified as an applicable aging effect for components in the steam and power conversion systems.

RNP Response:

Material fatigue resulting from vibration has been observed in the nuclear industry and can result in crack initiation/growth. Vibration induced fatigue is fast acting, is typically detected early in a component's service life, and is corrected to prevent recurrence. Corrective actions usually involve modifications to the plant, such as the addition of supplemental restraints to a piping system, the replacement of tubing with flexible hoses, or the isolation/elimination of the vibration source when possible. Based upon these considerations, cracking due to vibrational fatigue is not considered an applicable aging effect for the period of extended operation of the plant.

RAI 3.4.1-2

The main steam system flow venturi are within the scope of license renewal but are not specifically identified by the applicant as requiring aging management. Explain why these venturi do not require aging management or identify the aging effects and aging management programs for these components.

RNP Response:

The main steam flow venturis are constructed of stainless steel (for high wear parts) and carbon steel.

For the stainless steel parts, cracking due to thermal fatigue was identified as an applicable aging effect/mechanism. This is addressed in LRA Table 3.4-1, Item 1. These stainless steel parts were also identified as susceptible to "Loss of Material due to Crevice and Pitting Corrosion" and "Cracking due to SCC," and were therefore included in LRA Table 3.4-2, Items 2 and 8.

For the carbon steel parts of the main steam flow venturis, "Loss of Material due to Aggressive Chemical Attack," and "Crevice Corrosion and Pitting Corrosion" were identified as applicable aging effects/mechanisms. Accordingly, these mechanisms are discussed in LRA Table 3.4-1, Items 7 and 13. In addition, the carbon steel parts of these venturis were found to be susceptible to "Loss of Material due to General and Galvanic Corrosion." These effects/mechanisms are appropriately addressed in LRA Table 3.4-2, Item 7.

Steam is not a liquid and therefore does not act as an electrolyte which is necessary for galvanic corrosion to occur. However, the RNP methodology conservatively treats steam as "treated water" with respect to this aging effect. Therefore, as stated above, galvanic corrosion was identified as a potential aging effect for the subject flow venturis.

RAI 3.4.1-3

Table 3.4-1, row 1 of the LRA identifies components in the main feedwater, steam line, and AFW piping as requiring aging management for cumulative fatigue damage and states that evaluation of these components are consistent with GALL. LRA Table 2.3-27 for Steam Generator Blowdown System and Table 2.3-31 for the Steam Generator Chemical Addition System also reference Table 3.4-1, row 1 of the LRA and indicate that aging management of the identified components is consistent with GALL. However, the GALL does not address cumulative fatigue damage for these systems. Please explain the basis for concluding that RNP is consistent with GALL regarding cumulative fatigue damage for Steam Generator Blowdown System and for the Steam Generator Chemical Addition System.

RNP Response:

Since GALL does not address cumulative fatigue damage for the SGBD, this aging effect/mechanism should have been included with LRA Table 3.4-2 for the SGBD system. The AMR process identified "Loss of Material Due to Thermal Fatigue" for stainless steel valves and flow elements, and for carbon steel piping, fittings, and valves subjected to treated water within the SGBD system. The AMR results evaluated this aging effect/mechanism as a TLAA.

LRA Table 2.3-31 for the steam generator chemical addition system also references LRA Table 3.4-1, Item 1. Although the steam generator chemical addition system is not a part of the steam and power conversion system, the pressure boundary for the feedwater and AFW systems includes several small sections of chemical addition system piping and isolation valves. These components provide a pressure boundary intended function for the AFW and FW systems. Therefore, it is appropriate to reference LRA Table 3.4-1, Item 1, for the steam generator chemical addition system. These piping segments are shown on Drawing G-190204CLR, Sheet 1 (see LRA Section 2.3.4.11).

RAI 3.4.1-4

In Table 3.4-1, row 3 of the LRA, the applicant does not manage raw water exposure to AFW piping. In the discussion column, the applicant states that backup supplies of raw water are available from the Service Water System and the Deepwell Pumps but the backup supplies are not normally aligned. The applicant further states that raw water exposure to AFW piping is an extraordinary event and is not considered to be an applicable environment for license renewal. Please explain what is meant by the statement that, "the backup supplies are not normally aligned," and how the applicant has verified that the AFW piping has not been exposed to raw water.

RNP Response:

As shown on Drawings G-190197LR, Sheet 4, and G-190202LR, Sheet 3, both isolation valves on the service water (SW-118 and AFW-24) and the deep well water backup (DW-19 and DW-21) are normally locked closed with the telltale drain valves (AFW-24A and DW-20) open to prevent the flow of untreated water. The telltale drain would provide indication of valve leakage and corrective maintenance would be initiated/performed. The AFW system would only be exposed to service water (untreated water) if the CST becomes unavailable during a plant event requiring operation of the AFW system. These contingency measures would be directed by the plant emergency operating procedures.

RAI 3.4.1-5

In Table 3.4-1, row 4 of the LRA, the applicant's aging management review for Auxiliary Feedwater system pump lubricating oil coolers determined that water contamination of lube oil is not a credible environment because the lube oil system is a closed system. The staff's position is that an environment of lubricating oil contaminated with water may cause loss of material of carbon or stainless steel components due to general corrosion (carbon steel only), pitting, crevice corrosion and microbiological influenced corrosion. The Auxiliary Feedwater system pump lubricating oil coolers have the potential of being contaminated with water. Explain why water contamination in the lube oil is not considered a credible environment and why oil samples taken to verify no water contamination in the lube oil is not credited for license renewal.

RNP Response:

The AFW pump lubricating oil coolers are closed systems. These coolers are exposed to service water (raw water) on the tube side and lubricating oil on the shell side. The component intended functions for these heat exchangers includes both "heat transfer" and "pressure boundary." Pressure boundary components of these heat exchangers have been evaluated with respect to the material and operating environment. The only way for the lube oil side to be contaminated with raw water is by the failure of the interfacing pressure boundary. Since these heat exchangers have been evaluated for any aging effect that may result in a loss of pressure boundary, the AMR should not assume contamination of the lube oil. A review of operating experience did not identify history of water intrusion for the subject oil coolers.

The oil coolers for the motor-driven and steam-driven AFW pumps have been deemed susceptible to age-related degradation on the raw water side of the heat exchangers (tube-side). These aging effects are managed by the Open Cycle Cooling Water System Program and the Preventive Maintenance Program, as well as the Selective Leaching Program. Assigned PM activities are credited in the Preventive Maintenance Program AMP to manage the identified aging effects. The current inspection intervals are yearly for the motor-driven AFW AFW pump oil coolers and every 18 months for the steam-driven pump oil coolers. The subject coolers are cleaned, inspected, and tested under the RNP Preventive Maintenance Program. The sacrificial anodes are also inspected and replaced, if necessary.

RAI 3.4.1-6

For Table 3.4-1, row 5 of the LRA, the GALL specifies a plant specific program to manage the aging effects for the external surface of carbon steel components. In the discussion column, the applicant states that the Systems Monitoring Program which is used to manage aging for these components is considered consistent with the GALL. Explain how the System Monitoring Program is consistent with GALL if the GALL does not contain a program to manage this aging effect and directs the applicant to develop its own plant specific program.

RNP Response:

Since GALL does not contain a program to manage this aging effect, RNP will rely on a plant specific program to manage loss of material due to general corrosion for this Component/Commodity Group. This does not represent a change to the RNP LRA, but clarifies the original intent of LRA Table 3.4-1, row 5.

RAI 3.4.1-7

In Table 3.4-1, row 6 of the LRA, the applicant states that the Turbine and Extraction Steam Systems are not in scope for license renewal. In the scoping sections 2.3.4.1 & 2.3.4.4, RNP states that these systems are in the scope of license renewal but are not subject to AMR. The applicant is requested to clarify if the Turbine and Extraction Steam Systems are in scope for license renewal. If it is determined that these systems are in scope, identify if any components subject to AMR.

RNP Response:

Please refer to the RNP Response to RAI 2.3.4.4-4.

RAI 3.4.1-8

In Table 3.4-2, row 10 of the LRA, the applicant states that the carbon steel steam and motor driven AFW pump lube oil heat exchanger waterbox is managed for loss of material from galvanic corrosion in a raw water environment. Explain how the open-cycle cooling water system program manages for loss the material from galvanic corrosion in a raw water environment.

RNP Response:

The Open Cycle Cooling Water System Program credits routine inspections for the subject safety-related heat exchangers associated with the Cooling Water Reliability Program (NRC GL 89-13). These inspections are tracked by PM activities and managed by the Preventive Maintenance Program AMP. See the RNP Response to RAI 3.4.1-5 for more information relating to these oil coolers.

RAI 3.4.1-9

LRA section 2.3.4 lists SPC systems that are not addressed in GALL but the applicant asserts that aging management programs for these systems are consistent with GALL:

a) In Table 2.3-31 of the LRA, the applicant states that steam generator chemical addition system valves, piping and fittings are consistent with GALL using links to Table 3.4-1, rows 1, 2 & 5 (for TLAA and water chemistry/one-time inspection). Since GALL does not address the steam generator chemical addition system, how can RNP affirm that the AMPs for the components in the system are consistent with GALL? Explain how the aging management programs in Table 3.4-1, rows 1, 2 & 5 for the steam generator chemical addition system valves, piping and fittings are consistent with GALL.

b) In Section 2.3.4.7 of the LRA, the applicant states that aging management of the steam cycle sampling system heat exchangers (which samples from the SG blowdown system) are consistent with GALL in Table 2.3-9 (SG Blowdown Heat Exchanger Shell) using links to Table 3.4-1, row 10. Since GALL does not address the steam sampling system, how can the applicant assert that the proposed AMP is consistent with GALL? Explain how the aging management program in Table 3.4-1, row 10 for the steam cycle sampling system heat exchangers is consistent with GALL.

c) In Table 2.3-32 of the LRA, the applicant states that circulating water system piping and fittings are consistent with GALL using links to Table 3.3-1, row 20. Since GALL does not address the circulating water system, how can the applicant assert that these components are consistent with GALL? Explain how the AMPs for components in the circulating water system in Table 3.3-1, row 20, are considered consistent with GALL.

RNP Response:

a) LRA Table 2.3-31 for the steam generator chemical addition system references LRA Table 3.4-1, Items 1, 2 and 5. As shown on the flow diagram for the sg chemical addition system (G-190204CLR), the system includes several small sections of piping that are part of the feedwater system and the AFW system pressure boundaries. As such, the SG chemical addition system is essentially an extension of the feedwater system and AFW systems. Therefore, it is appropriate to reference LRA Table 3.4-1, Item 1, for the SG chemical addition system.

b) The steam generator blowdown sample heat exchangers should not have been identified being consistent with in GALL. These heat exchangers (coolers) are required to maintain system pressure boundary for the CCW system (ref. Drawing No. 5379-376LR, Sheet 1 of 4). The AMR identified crevice and pitting corrosion for the stainless steel tubing subjected to a treated water environment. The AMR identified general, crevice, and pitting corrosion for the carbon steel shell subjected to treated water. These identified aging effects are managed by the Closed Cycle Cooling Water System Program.

c) Although line number 2-CW-077-175 is designated as a component in the circulating water system, this piping segment is integral to the fire protection system pressure boundary (see HBR2-8255LR, Sheet 1). However, since this component is aluminum, which is not addressed in GALL, the component and associated aging effects/mechanisms are addressed in LRA Table 3.3-2, Item 18. The CW components are addressed in Table 3.3-1, Item 20, only to the extent necessary to state they are not consistent with GALL. Thus, Table 3.3-1, Item 20, is not intended to indicate that the CW system components are consistent with GALL.

RAI 3.4.1-10

In Table 3.4-2, row 1 of the LRA, the applicant states that the water chemistry program manages galvanic corrosion because it limits electrolytes in the treated water. Since the treated water does contain electrolytes, explain the basis for asserting that electrolyte level in the SPCS treated water is below the threshold to produce galvanic corrosion.

RNP Response:

Galvanic corrosion is managed through the RNP Water Chemistry Program using the same methods applied for crevice corrosion, general corrosion, pitting corrosion, and stress corrosion cracking. The RNP Water Chemistry Program requires monitoring and controlling of secondary water chemistry parameters. The parameter limits in effect for steam and power conversion systems are based upon the EPRI PWR Secondary Water Chemistry Guidelines, TR-102134. This includes controls for pH level and cation conductivity, and includes concentration limits for sodium, fluoride, chloride, sulfate, silica, dissolved oxygen, iron, copper, and hydrazine. In the LRA, these activities were summarized using the term "limiting electrolytes." In total, these controls have been shown by operating experience to have been effective in minimizing each form of electrochemical corrosion, including galvanic corrosion, pitting corrosion, crevice corrosion, general corrosion, and SCC.

RAI 3.4.1-11

In Table 3.4-2, row 11 of the LRA, the applicant states that the external surface of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). On such basis, the applicant contends that the AFW pump and turbine; AFW lube oil heat exchanger and lube oil pump and; valves, piping tubing and fittings of various systems that are located indoor (not air conditioned) and are fabricated from carbon steel, do not require aging management for loss of material due to external corrosion. The staff position is that air, moisture, or humidity provides an environment for loss of material in components due to general corrosion of carbon and low alloy steels in both indoor and outdoor environments. Explain the basis for concluding that the external surface of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage).

RNP Response:

See the RNP Response to RAI 3.2.1-1.

RAI 3.4.1-12

In Table 3.3.2, row 31 of the LRA, the applicant states that there are no aging effects for circulating water system concrete piping in raw water and buried environments. Operating experience has shown that concrete in a raw water environment is susceptible to cracking. Please explain your basis for this conclusion and why this SPC system line Item was placed in the auxiliary system Table 3.3-2 of the LRA and not in the SPC system Table 3.4-2.

RNP Response:

LRA Table 3.3-2, Item 31, indicates that there are no aging effects requiring management for the concrete pipe in the circulating water system. The concrete pipe provides a return flow path for the SWS back to Lake Robinson. The safety related portion of the SWS return flow path terminates at the RAB wall. Downstream of this point the discharge flow path routes through a section of 30 inch SWS piping into the 126 inch diameter concrete circulating water system discharge line, and then to the discharge canal. The license renewal review determined that the pressure boundary integrity of the non-safety related SWS piping and the circulating water system concrete piping is not critical, however, it is necessary that they remain available and unrestricted as a discharge flow path to ensure performance of safety-related SWS functions. Therefore, degradation of the concrete pipe that could result in leakage would not adversely affect any license renewal intended function. Degradation that could restrict flow through the concrete piping would be detected as a degradation of the performance of the circulating water system, which has a much higher flow rate through this pipe during normal operation than required for SWS discharge flow.

The circulating water system was included in auxiliary systems, not the steam and power conversion systems, primarily because the circulating water system intended functions involve extensions of the pressure boundaries of service water and fire protection systems. The circulating water system performs no intended functions as a steam and power conversion system.

RAI 3.4.1-13

In Table 2.3.9 of the LRA, the applicant lists the commodity group "SG Blowdown Heat Exchanger Shell" and links aging management to Table 3.3.1, row 13, which is the auxiliary system. Is this link to Table 3.3.1 correct or should it be Table 3.4.1, row 13 in the steam and power conversion system table. If Table 3.3.1, row 13 is correct, please explain your basis.

RNP Response:

The SGBD sample heat exchanger is in the secondary sampling system and has a component intended function only as the system pressure boundary for the CCW system. Therefore, for license renewal purposes, this component is evaluated with the CCW system and the link to Table 3.3.1, Item 13, is correct.

Note: In LRA Table 2.39 this component should have been labeled "SG Blowdown Sample Heat Exchanger Shell."

RAI 3.5.1-1

Item 28, Table 3.5-1 of the LRA states that reactor vessel nozzle supports are inaccessible and not currently inspected under the RNP ASME Section XI, Subsection IWF program and that RNP plans to implement an inspection under the One-Time Inspection Program to verify effective management of potential corrosion of the supports. Discuss the specific steps to be adopted in performing the one time inspection of the inaccessible nozzle supports and provide the basis for concluding that an one time inspection would suffice to ensure effective aging management of these inaccessible supports. Also, discuss past plant operating experience related to inspection and aging management of the reactor vessel nozzle supports.

RNP Response:

RNP has elected to remove the reactor vessel nozzle supports from the One-Time Inspection Program and will include them within the ASME Section XI, Subsection IWF Program. Therefore, a reactor vessel nozzle support will be inspected by the IWF Program during the Fourth Ten-Year ISI Interval prior to the end of the current 40-year Operating License. Due to the limited accessibility of the supports, a limited visual inspection will be made using remote visual technology. The reactor vessel nozzle supports will continue to be inspected by the ASME Section XI, Subsection IWF Program during the period of extended operation.

A review of operating experience (OE) indicated a condition report was identified in April 2001 (during Refueling Outage-21). This OE information was a consideration in the decision to include the reactor vessel nozzle supports in the ASME Section XI, Subsection IWF Program.

LRA Table 2.4-1, "Reactor Vessel Support," should refer to LRA Table 3.5-1 Items 27 and 28, for AMR results.

The LRA Table 3.5-1, Group 28, Discussion, should have the discussion of the reactor vessel nozzle supports deleted.

The reactor vessel support structure, including the slide bearing plates should be deleted from the LRA Sections A.3.1.31 and B.4.4 and should be included in LRA Sections A.3.1.6 and B.2.6, respectively.

The information in LRA Subsection A.3.1.31, One-Time Inspection Program, is modified to delete reactor vessel supports. As a result of this RAI and RAI B.3.10-6, the program description now reads:

"Special inspections of components within the scope of license renewal will be performed in accordance with the One-Time Inspection Program. The Program is used to verify the effectiveness of the aging management activities and to determine the present condition of components. One-Time Inspection Program activities consist of inspecting (1) the CCW heat exchanger tubes, (2) miscellaneous piping protected by the Water Chemistry Program, (3) small bore RCS and connected piping, (4) EDG exhaust silencers, (5) containment liner plate and moisture barrier, and (6) the Diesel Fire Pump Fuel Oil Tank."

RAI 3.5.1-2

With respect to Item 9, Table 3.5-2 of the LRA, discuss the basis for determining that carbon steel components completely encased in RNP concrete would not experience loss of material without consideration of the condition and pH values of the encasing concrete. Discuss past RNP operating experience with respect to the aging management of steel components encased in concrete to further support RNP's above determination.

RNP Response:

The basis for determining that carbon steel components completely encased in RNP concrete would experience no loss of material aging effect includes consideration of the concrete design, in combination with the highly alkaline environment of concrete, and no plant operating experience identifying corrosion of embedded steel as an issue.

Section 3.8.1.6.1.2 of the UFSAR states: "All reinforcing steel and frames which form an extension of the reinforcing steel are encased completely within the highly alkaline environment of the concrete wall and dome and are, therefore, protected from corrosion." Section 3.8.1.6.1.3 of the UFSAR states: "Concrete has been used successfully for many years as a protective covering for steel." As specified in NUREG-1557, and referenced in the GALL, the attributes of a concrete design for which corrosion is not significant are the same as specified for the RNP concrete design, specifically the concrete design is per ACI 318-63 with a low water-to-cement ratio and adequate air entrainment. Plant operating experience supporting this position is found in the corrosion inspection reports for the grouted surveillance tendons, which notes in the conclusions: "Based upon the results of the investigations documented in this report, it is concluded that there is no significant corrosion in the Robinson Nuclear Power Plant 25-year containment surveillance block provided for investigation." Additionally, the absence of any deficiencies identified in the Corrective Action Program, associated with the loss of material from embedded components, provides further evidence that the aging effect is not credible for the subject components.

A combination of all the attributes listed above discussion provides reasonable assurance that carbon steel components completely encased in RNP concrete would experience no loss of material aging effect.

RAI 3.5.1-3

Embedded steel for below-grade concrete structures that are exposed to an aggressive ground water environment is susceptible to loss of material due to aggressive chemical attack. Referring to the ground water acidity discussion of Item 7, Table 3.5-1 of the LRA, provide available RNP ground water chemistry test results including chlorides, sulphate and pH values. Also, discuss the proposed aging management (scope, detection of aging effects, parameters monitored, acceptance criteria) and past inspections and condition of below-grade concrete at RNP.

RNP Response:

Based on a long-term environmental monitoring report, from 1975 to 1995, the following environmental parameters have been identified for lake water at the intake structure:

Average Chloride Concentration	3.14 ppm
Average Sulfate Concentration	3.67 ppm
Average pH	5.46

Based on semi-annual ground water monitoring reports, required by the State of South Carolina, the following environmental parameters have been identified from Well #4.

Chloride Concentration	No Data Available
Sulfate Concentration	21.0 ppm
Ground Water pH	4.41

Based on the relatively low pH value for both ground water and lake water, an aggressive environment was assumed for the determination of aging effects associated with below grade concrete.

The intended scope for the inspection of below grade concrete, related to Item 7 of LRA Table 3.5-1, includes the concrete foundation and below grade walls for the Containment structure. The referenced aging management program for this item is the Containment ISI Program for IWL, which implemented through two plant procedures, the IWL inspection procedure and the site excavation backfill procedure.

The inspection of inaccessible, below grade, concrete will be performed using the inspection criteria of ASME Section XI, Subsection IWL, for the subject item, however, the frequency requirements of IWL will not be implemented. Per IWL-2510, the concrete surface areas shall be visually examined in accordance with IWL-2310(a) for evidence of conditions indicative of damage or degradation, such as defined in ACI 201.1. The RNP Subsection IWL inspections presently examine exposed concrete surfaces for evidence of conditions indicative of damage or degradation, such as active leaching, active corrosion staining, popouts, scaling, spalling, cracks, and other damage, deformation or degradation. Inaccessible concrete will be inspected when it is exposed during plant excavations for other activities. The site excavation procedure requires the user to notify design engineering of proposed excavations and requires an inspection prior to backfilling against exposed concrete surfaces. Excavations will not be performed with the sole purpose of concrete inspection. However, 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, and chloride and sulfate levels are well below the trigger levels). As such, inspection results of the submerged portions should envelope aging effects encountered by below grade concrete of other structures.

For additional information regarding inspection of inaccessible, below grade, concrete associated with outside areas (not the containment pressure boundary) please refer to the RNP Response to RAI 3.5.1-10.

RAI 3.5.1-4

The discussion column of Item 4, Table 3.5-2 of the LRA states that ASME Section XI, Subsection IWL activities ensure concrete cracking and change in material properties due to fatigue are monitored. Based on past RNP specific operating experience related to this monitoring activity, discuss incidents of observed degradation due to fatigue, their disposition and the adequacy of the AMP.

RNP Response:

There has been no observed concrete degradation at RNP attributed to fatigue. As a conservative measure, RNP included this aging mechanism/effect since the existing ASME Section XI, Subsection IWL Program already monitors for concrete cracking and change in material properties. This aging effect was determined to only be potentially applicable at five hot pipe penetration locations where there are no bellows. LRA Section B.3.14 identifies RNP-specific OE associated with the ASME Section XI, Subsection IWL Program. Degradation discovered was determined to be minor.

RAI 3.5.1-5

Items 2 and 11 of Table 3.5-2 of the LRA state, in part, that the RNP AMR determined that stainless steel and galvanized steel components would experience no aging effects requiring management when subject to a borated water leakage environment. As applicable, discuss past incidents of borated water leakage including ponding of leaked borated water at RNP as operating experience based data to further support your determination that no AMP is needed for components listed in Items 2 and 11 of the table. Additionally, referring to Item 12 of Table 3.5-2, the staff is concerned that in a wetted or highly moisturized air environment, an AMP may be needed for the stainless steel threaded fasteners. On this basis, please confirm that, for RNP, there are no containment stainless steel threaded fasteners used in a wetted or highly moist air environment. Otherwise, justify why threaded fasteners in a wetted or moist environment need no AMP to manage loss of material aging effect.

RNP Response:

For galvanized steel, no operating experience examples were identified regarding borated water leaks causing aging to the galvanized steel components identified in LRA Table 3.5-2, Items 2 and 11. As a conservative measure, RNP has decided to include loss of material due to corrosion for galvanized steel in a borated water leakage environment as an aging effect/mechanism. As such, Borated Water Leakage environment should be deleted as an applicable environment in LRA Table 3.5-2, Item 2. In addition, galvanized steel should be deleted as a material and from the discussion column of LRA Table 3.5-2, Item 11. In LRA Table 3.5-1, Item 16, the discussion column for steel should include galvanized steel.

For stainless steel, no operating experience examples were identified regarding borated water leaks causing aging to the stainless steel components identified in LRA Table 3.5-2, Items 2 and 11. At RNP, LR did not identify occurrences of stainless steel threaded fasteners in a wetted or highly moist environment.

RAI 3.5.1-6

No aging effects are listed by RNP based on its AMR for components listed in Items 13 through 16 of Tables 3.5-2 of the LRA. The staff is concerned with the potential loss of material aging effect associated with (a) slide bearing plates consisting of a bronze material impregnated with Lubrite; (b) manganese bronze threaded fasteners, and (c) carbon steel structural supports of the spreading room raised floors. The staff is also concerned with the potential loss of material and cracking aging effects for (a) containment liner insulation consisting of PVC or Polyimide foam panels; (b) control room ceiling tiles, and (c) the penetration insulation fabricated from fiberglass blankets and ceramic fiber. For each of the above materials, discuss any RNP aging management related operating experience including the results of past inspections.

RNP Response:

The threaded fasteners identified in Item 13 of LRA Table 3.5-2 were originally identified as manganese bronze on plant drawings. Further review of the subject fasteners (used for the blind flange of the fuel transfer tube) has determined that they have been replaced with 316 stainless steel. As such, these threaded fasteners are addressed under Item 12 of Table 3.5-2 and not under item 13.

The slide bearing plates identified in Item 13 of LRA Table 3.5-2 are fabricated from copper alloys (bronze material) impregnated with a graphitic lubricant with the trade name Lubrite or Lubron. Item 13 was used to categorize the copper alloy component or bronze material. Item 14 of LRA Table 3.5-2 was used to categorize the miscellaneous component or the graphite based lubricant. ASM Handbook, Volume 13, Corrosion – page 617, describes the corrosive ratings for various copper alloys in boric acid as "Excellent: resists corrosion under almost all conditions of service."

Lubrite lubricant has a low coefficient of friction, resists softening at elevated temperatures, resists deformation, and absorbs grit and abrasive particles. Lubrite is not susceptible to corrosion, tolerates high intensities of radiation, and will not score or mar. Lubrite products are permanent, solid, completely self-lubricating, and require no maintenance, as documented in NUREG-1759, "Safety Evaluation Report related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4." The graphite lubricant is known to be stable for high temperature exposure for long periods of time, and with no compromise of its structural integrity or lubricating capabilities. Additionally, ISI inspection reports for the reactor coolant pump supports and steam generator supports have identified no recordable indications associated with slide bearing plates for inspections performed in 2001, 1998, 1993, 1990, 1986, and 1984. As such, based on the documented corrosion resistance of copper alloys in conjunction with the absence of any reported deficiencies, there is reasonable assurance the subject item will experience no credible aging effects requiring an AMP.

The containment liner insulation is fabricated from a pvc or polymide foam. The subject insulation is used for thermal insulation of the containment liner, and is in direct contact with the external surface of the liner on one side, and is covered with a stainless steel sheathing (sheetmetal) on the other side. The liner insulation must be removed to inspect the containment liner. The insulation is a rigid board approximately 1-1/4" thick, and is occasionally damaged during the removal process to inspect the liner. Replacement of these anels is determined by their condition. There have not been specific inspections performed for the insulation panels, but, inspection reports for liner have not identified age related degradation of the insulation, and no condition reports have been identified that are associated with liner insulation degradation. Therefore, based on an absence of age related degradation operational experience, there is reasonable assurance that the containment liner insulation will experience no credible aging effects requiring an AMP.

The containment penetration insulation commodities are identified as high density penetration insulation (BTU-BLOCK Flexible by Manville) and fiberglass blankets for the main steam lines, and ceramic fiber insulation for the steam generator blowdown lines. The subject insulation is located in the containment air environment not subject to boric acid leaks. No aging effects have been identified based on review of RNP operating experience, and based on the protective location of the subject insulation (inside penetrations), no mechanical degradation is expected. Therefore, no aging effects are identified that require management and an aging management program is not required.

For the control room ceiling the acoustical ceiling tiles are mineral fiberboard, Minaboard Fireguard series, Cortega Model No. 823, manufactured by Armstrong. The suspended grid system for the acoustical tile is a heavy duty exposed tee system by Armstrong. The control room ceiling is supported by a combination of structural steel, threaded rod, and unistrut attached to the building by welding or expansion bolts. The material is either coated steel or galvanized steel.

The control room raised floor raised access floor system is constructed of epoxy painted carbon steel pedestals, stringers, and floor panels furnished by Tate Access Floors, Inc. Fasteners are either carbon steel or galvanized steel. The floor system is attached to the structure by expansion bolts. Carpet is fastened to the floor panels by adhesive and is replaceable. The access floor system is designed for the design basis earthquake loads to preclude damage to safety related components.

The cable spread room raised floor raised access floor system is constructed of epoxy painted carbon steel pedestals, stringers, and perforated floor panels furnished by Tate Access Floors, Inc. Fasteners are either carbon steel or galvanized steel. The floor system is attached to the structure by adhesive and expansion bolts.

The control room and cable spreading room are indoor-air-conditioned environments. Therefore, the carbon steel structural supports for the control room and cable spreading room raised floors do not require aging management.

Additionally, based on RNP operating experience, no aging effects requiring management for the control room ceiling material or raised floors have been identified. Therefore, no aging management program is required.

RAI 3.5.1-7

Item 12, Table 3.5-1 of the LRA, Section 10.4.3 of the ISI Summary Report, referred to in the discussion column, states that the CV Liner at this insulation location was evaluated against the acceptance criteria in procedure CM-764, "Inspection and Repair of CV Liner and Insulation," and determined to be acceptable. In fact, the degradation was less severe than the CV Liner degradation observed on the lowest row of CV Liner immediately above the concrete floor. The other areas below the concrete were evaluated as acceptable by comparison to the CV Liner below the concrete at this insulation location. This evaluation was documented in ESR 99-0005, Revision 3, Attachment B with the conclusion that the other "inaccessible" areas below the concrete are acceptable for continued service until 2005. The staff is concerned with the potential for loss of material associated with inaccessible CV liners located below the concrete. Explain how the portions of inaccessible CV liners that are located below the concrete were evaluated and briefly summarize the basis for concluding that the other "inaccessible" areas below the concrete are acceptable for continued service until 2005.

RNP Response:

The letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0125: "Submittal of 90 Day Inservice Inspection Summary Report," dated August 10, 2001, addresses the conclusions stated in the LRA. Also, please refer to the RNP Response to RAI 3.5.1-19 for additional information on inspection of liner plate and moisture barrier.

A section of the liner was examined (approximately 1 foot deep by 4 feet long in a pre-existing void) below the concrete floor at the 228 foot elevation. A visual examination determined there were tightly adhered corrosion products on the liner surface. A UT examination for actual liner plate thickness determined there was no loss of material thickness. Water samples located in this void area were alkaline, stagnant, low re-oxygenation, low chloride concentration, and low boron concentration. The vertical liner below the concrete floor was in better condition than and less pitted the liner surface immediately above the concrete floor. The liner surface immediately above the concrete floor had pitting corrosion up to 0.1875 inch which was the worst case. This corrosion rate was estimated based on the worst-case degradation occurring from the containment flooding event in 1975 to the liner inspections in 1988 (0.1875 inch/23 years). The corrosion rate was then applied to the difference between the actual thickness examined for the liner and minimum design thickness. The worst-case corrosion area above the concrete was determined to conservatively meet the liner design thickness until year 2005. The liner plate thickness below the concrete, which had no degradation, was determined to be acceptable (exceeding the minimum wall thickness) for continued service until 2005. By 2005, either further evaluation or inspection will be required for the inaccessible portion of the liner below the concrete. Application of this worst-case corrosion rate to the portion of the liner below the concrete conservatively did not take into account that the liner plate horizontal and vertical surfaces are in intimate contact with concrete. In fact, the concrete surface at the interface point between the concrete and liner plate was probed by engineering with a hard, blunt instrument and determined to be acceptable to inhibit borated water from migrating down the interface surface to the horizontal liner plate. This provides a measure of corrosion protection to the liner plate, as described in the UFSAR Section 3.8.1.6.1.5 and the RNP Response to RAI 3.5.1-2.

The minimum acceptable thickness for the liner plate in question was calculated based on the ASME Code (Section XI, Subsection IWE, 1992 Edition, 1992 Addenda, Section 3.122.4); yield stress due to stud loads, design pressure and compressive load; and, elastic stability.

RAI 3.5.1-8

Table 3.5-1, Item 16, although lists RNP's Structures Monitoring Program (SMP) under the aging management program (AMP) column of the table, states in the discussion that the AMR concluded that above-grade concrete/grout structures have no aging effects. The same discussion makes reference to Item 10 of Table 3.5-2, which, in turn, indicates that no AMP is required. Table 3.5-1, Item 20 states that no aging effects are applicable to masonry walls, although, it lists masonry wall program as its AMP. Table 3.5-2, Item 10 states that reinforced concrete and grout, including concrete sump, in the environment of containment air, indoor-not air conditioned, and outdoor, would experience no aging effects requiring management. Considering the vulnerability of concrete structural components, including masonry blocks and grouts, the staff has required previous license renewal applicants to implement an aging management program to manage the aging of these components. The staff position is that cracking, loss of material, and change in material properties are plausible and applicable aging effects for concrete components inside containment as well as for other structures outside containment. For inaccessible concrete components, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive; however, for all other concrete components, the staff believes an inspection through an aging management program is required. Please confirm that RNP will credit appropriate aging management program(s) to manage the aging effects consistent with the staff position for concrete, masonry blocks, and grout.

RNP Response:

The letter from J. Moyer (CP&L) to NRC, Serial: RNP-RA/02-0159: "Supplement to Application for Renewal of Operating License," dated October 23, 2002, addresses aging management of concrete components. RNP committed to an aging management program for monitoring accessible concrete based on Interim Staff Guidance, and agreed to credit the Structures Monitoring Program and the Dam Inspection Program for examination of accessible concrete. The Component/Commodity Group of "Reinforced Concrete" or "Concrete Tank Foundation" includes grout. Masonry block walls were not specifically identified in the October 23, 2002, letter. However, the Structures Monitoring Program is credited for monitoring the masonry block walls.

LRA Table 3.5.1, Item 16, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible concrete.

LRA Table 3.5-2, Item 10, should be deleted.

LRA Table 3.5.1, Item 20, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible masonry walls.

Based on GALL XI.S5, the Structures Monitoring Program can be used for the aging management of masonry walls.

RAI 3.5.1-9

In Table 3.5-1, Item 7, the applicant states that the ASME Section XI, Subsection IWL Program is applicable to the Containment Structure. The applicant states in the discussion that the aging mechanisms associated with aggressive chemical attack and corrosion of embedded steel are potentially applicable to below grade concrete structures due to slightly acidic ground water. The staff concurs with this assessment and believes that the aging effect resulting from potential loss of material of below-grade concrete components should be adequately managed. RNP further states that, owing to the slightly acidic groundwater at the site, they will enhance the inspection requirements of the IWL Program to apply a special provision for monitoring aging effects, which "involves inspecting the condition of below-grade concrete that is exposed during excavation." The staff interprets these statements to imply that the applicant has credited the ASME Section XI, Subsection IWL Program, for below-grade containment concrete. If the applicant disagrees with the staff interpretation, please respond accordingly. The staff is unclear as to how the inspection for below-grade containment concrete will be performed by the ASME Section XI, Subsection IWL Program. Provide additional information, such as the locations, depth, and frequency of soil excavation, related to the aging management of below-grade containment concrete.

RNP Response:

Refer to the RNP Response to RAI 3.5.1-3.

RAI 3.5.1-10

Table 3.5-1, Item 17, states that the Structures Monitoring Program is applicable for inaccessible concrete components, such as exterior walls below-grade and foundation. The applicant states that, owing to the slightly acidic groundwater at the site, the applicant will inspect below-grade concrete and grout that is exposed during excavation. Given the reported slightly acidic pH of RNP's ground water, the staff believes that the aging effect resulting from potential loss of material of below-grade concrete components should be adequately managed. The staff position for managing aging effects of in-scope concrete components is provided in RAI 3.5.1-8. The staff interprets the above statements to mean the applicant has credited the Structures Monitoring Program for inaccessible concrete components, and they will also perform inspection for below-grade concrete. The staff is unclear as to how the inspection for below-grade Class I structural concrete will be performed by an RNP plant specific AMP. Provide additional information, such as the locations, depth, and frequency of soil excavation, related to the aging management of below-grade containment concrete.

RNP Response:

Inspection of inaccessible, below grade concrete will be performed using the concrete inspection criteria of the Structures Monitoring Program for the subject item., e.g., planned construction, corrective maintenance, etc. Inaccessible, below grade, concrete will be inspected when it is exposed during plant excavations for other activities. The site excavation procedure requires notification of Engineering for proposed excavations, and requires an inspection prior to backfilling. Such 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, and chloride and sulfate levels are well below the trigger levels). Therefore, inspection results of the submerged portions should envelope aging effects encountered by below grade concrete of other structures.

For additional information regarding inspection of inaccessible, below grade, concrete associated with the containment pressure boundary, please refer to the RNP Response to RAI 3.5.1-3

RAI 3.5.1-11

In Table 3.5-1, Item 15, the applicant states that their AMR determined that the aging mechanism of reaction with aggregates was not applicable to RNP concrete elements because aggregates were selected in accordance with ACI and ASTM standards. The staff is concerned that some concrete containment under certain circumstances could experienced expansion and cracking due to reaction with aggregates which, in turn, could lead to loss of their intended functions. Please state the specific standards, such as ASTM C295-54 or ASTM C227-50, that were used to substantiate claim that the RNP concrete does not have the aging mechanism of reaction with aggregates.

RNP Response:

Section 3.8.1.6.1.1 of the UFSAR states: "Aggregates conform to "Standard Specifications for Concrete Aggregates" ASTM Designation C33 (latest revision at the time of construction was used). Fine aggregate consists of sharp, hard, strong, and durable sand free from adherent coating, clay loam, alkali organic material, or other deleterious substances. Cement was Type II as specified in "Standard Specifications for Portland Cement" ASTM Designation C150 (latest revision at the time of construction was used)."

ASTM C-33 references both C-227 and C-295.

However, based on Interim Staff Guidance on Concrete Aging, RNP has committed to the IWL Program for managing aging mechanisms of freeze-thaw and reaction with aggregates on accessible concrete, as stated in the letter from J. Moyer (CP&L) to NRC, Serial: RNP-RA/02-0159: "Supplement to Application for Renewal of Operating License," dated October 23, 2002.

RAI 3.5.1-12

Table 3.5-1, Item 23, states that RNP concrete elements do not exceed the temperature limits associated with aging degradation due to elevated temperature. The staff is concerned that sustained exposures of in-scope concrete components to high temperatures may lead to concrete cracking and change in material properties resulting in loss of intended component functions. Therefore, please discuss the highest temperatures of in-scope concrete elements at RNP with respect to general high temperature areas and localized hot spots and compare them to the ACI 349 Code temperature limits to substantiate the claim.

RNP Response:

No concrete elements at RNP exceed the ACI 349 Code temperature limits. The maximum ambient atmospheric air temperatures are as follows for the various RNP in-scope structures:

Outdoor	95°F	
Indoor Air Conditioned	85°F	
Indoor Not Air Conditioned	104°F	(excluding containment)
Containment	120°F	(bulk average temperature)

Based on initial conditions used in the design basis analyses, the containment bulk average temperature is maintained below 120°F and verified through Technical Specifications surveillances on a 24 hour frequency. As such, containment bulk average temperature is below the ACI normal operation value for general areas (i.e., 150°F).

The temperature of concrete in the vicinity of the reactor vessel is kept within acceptable limits by the reactor vessel insulation casing, air spacing between the insulation and primary shield wall, and supplemental cooling. Concrete in this area is managed by the Structures Monitoring Program and no degradation has been identified.

Localized hot spots within containment can be characterized as the pressurizer cubicle and the concrete surrounding hot piping penetrations. Documented temperatures for the pressurizer cubicle are as follows:

175°F (9% of the time)
165°F (25% of the time)
155°F (66% of the time)

These values are below the ACI 349 normal operation value for local areas (200°F).

There are no concrete areas around containment penetrations where sustained temperatures exceed 200°F. The concrete around an RHR penetration may exceed 200°F for limited time periods during plant heat-up and cool-down cycles. (See the RNP Response to RAI 4.6.3-1 for additional information regarding temperatures around the RHR penetration).

RAI 3.5.1-13

The staff position is that loss of material is a plausible and applicable aging effect for carbon steel components inside containment as well as for other structures outside containment, and an appropriate AMP should be credited to manage this aging effect. For carbon steel in an indoor-air-conditioned environment, the staff does not require aging management. In addition, for steel embedded in concrete in inaccessible areas, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive.

For some of the carbon steel structural components listed in Section 2.4, "Scoping and Screening Results - Structures," the staff was unable to verify that the aging effect(s) identified for these components in Table 3.5-1 of the LRA will be managed by an appropriate aging management program. Please provide clarification regarding the AMR conclusions for carbon steel structural components inside containment as well as for structures outside containment.

RNP Response:

Loss of material is an applicable aging effect for carbon steel components inside or outside containment and is managed by one of the following programs for the structural components listed in Section 2.4.

- Structures Monitoring Program
- Boric Acid Corrosion Program
- IWF Program
- IWE Program
- Appendix J Program
- One Time Inspection Program Recommended Guidelines for Safety Inspection of Dams.

These AMPs are considered to be appropriate for managing the aging effects for carbon steel components that were identified in the AMR.

RAI 3.5.1-14

Item 15 of Table 3.5-1 of the LRA states that based on the design specifications for the concrete, the aging mechanisms of freeze-thaw and reaction with aggregates are not applicable to RNP concrete elements. Please provide a summary of past operating experience, including findings from structural inspections of the exterior dome and wall of RNP containment, to support the above AMR determination that there are no aging effects due to freeze-thaw for RNP concrete.

RNP Response:

Inspections of structural concrete in the IWL Program have not identified deterioration of concrete as result of freeze-thaw and reaction with aggregates. The IWL Program examinations have identified staining, cracking, exposed aggregate and spalling of the containment cylinder wall concrete. However, these indications were evaluated and determined to be minor, passive, with no effect on the structural integrity of the containment. These were not attributed to freeze thaw or reaction with aggregates. A two inch thick sand-cement grout was installed on the containment dome during initial construction which served as a sacrificial finish or wearing surface. The grout layer was not part of the structural concrete, was not safety related, was not reinforced, and did not meet structural concrete requirements for water cement ratio and air entrainment. This surface cracked as a result of shrinkage and temperature fluctuations, and may have further deteriorated as a result of freezing action on moisture in the shrinkage cracks. Construction methods also contributed to the deteriorated surface. The surface was repaired and covered with a silicon/polyurethane coating system. The deteriorated grout was not considered typical of the high quality concrete placed in the structures. Based on the fact that the only indications of potential freeze-thaw at RNP were on non-structural grout and this is the only potential location for containment concrete to be saturated with water and exposed to freezing temperatures, freeze thaw was not determined to be an aging mechanism for structural concrete.

However, based on Interim Staff Guidance on Concrete Aging, RNP has committed to the IWL Program for managing aging mechanisms of freeze-thaw and reaction with aggregates on accessible concrete, as stated in the RNP letter from J. Moyer (CP&L) to NRC, Serial: RNP-RA/02-0159: "Supplement to Application for Renewal of Operating License," dated October 23, 2002.

RAI 3.5.1-15

Item 24, Table 3.5-1 of the LRA states that the RNP plant does not include tanks with liners. Are there in-scope concrete tanks without liners that are not included in Sections 3.1 through 3.4 of the LRA? If yes, please indicate the aging management program(s) that are credited to manage the aging of these concrete tanks.

RNP Response:

There are no in-scope concrete tanks with or without liners at RNP.

RAI 3.5.1-16

In discussing the AMR for the containment bellows in Item 2 of Table 3.5-1, the applicant summarizes the operating experience at RNP. Based on the operating experience, the applicant made a number of changes to the penetration design and piping insulation, and concluded that additional methods for detecting aging effects are not warranted. The applicant is requested to provide the following information in this context:

(a) Are all bellows (inside and outside) testable by Appendix J, Type B testing?
(b) Are there administrative leakage limits established for individual bellows which would detect the degradation of bellows during Type B testing?
(c) What is the frequency of testing penetrations with bellows during the extended period of operation?

RNP Response:

(a) Bellows (inside and outside containment) are testable by Appendix J, Type B testing.
(b) Administrative leakage limits are not established for individual penetrations that have bellows. However, administrative limits are established for groups of mechanical penetrations. If any group of mechanical penetrations exceeds its administrative limit, individual penetration(s) can be isolated for evaluation and repair. This allows detection of degradation of individual bellows on the penetrations during Type B testing.
The overall leakage limit is specified in the Technical Specifications section 5.5.16.
(c) Type B tests are conducted on a refueling outage interval, not to exceed a maximum interval of two years. This frequency of testing will continue to be used for the extended period of operation.

In addition, the following information is provided:

There are forty-six containment mechanical penetrations sleeves in the containment for pipes to pass through the cylindrical wall liner. Several of these wall penetration sleeves contain multiple pipes. Two additional piping penetrations are embedded in the base mat and extend from the ECCS Sump to the RHR Pump room outside the containment. Typical details of how the pipes are sealed to the containment liner are shown in the UFSAR Figure 3.8.1-15. Bellows installed at the penetration sleeves inside the containment are considered part of the containment pressure boundary. The bellows installed at the penetration sleeves outside the containment are not considered part of the containment pressure boundary, but are included in the local leak rate test boundaries. Eleven of the forty-eight mechanical penetrations sleeves are not constructed with bellows. Instead, these mechanical penetrations sleeves are sealed with welded pipe cap assemblies or sleeve seal plates. Thirty-seven have bellows either inside, outside, or both inside and outside the containment as identified on plant documents.

Locations, sizes and thickness of sleeve penetrations and information on bellows are shown on plant drawings and specifications. Original bellows installed were made of austenitic stainless steel ASME SA 240 Type 321. Replacement bellows installed have been constructed of ASME SB-443 Alloy 625 Grade 1. End plates and butt weld sleeve sealing plates are made of the same materials as the corresponding process piping. Some of the bellows are single ply and others are of double ply construction, as indicated in plant records.

A review of plant OE determined many of the original bellows have been replaced. Replacements were generally made due to excessive leakage from damaged bellows. The following OE provides assurance the 10 CFR 50 Appendix J Program has been successful at detection of leakage at penetration bellows and implementing actions to replace bellows as necessary.

Before 1992, several bellows were replaced with like-for-like bellows when leakage was identified. This was determined by monitoring the PPS which was used at that time to continuously provide design pressure to the containment penetrations. This system is now only used for testing. No aging mechanisms were determined for these replacement bellows.

On July 20, 1995, a potential breach of containment integrity was discovered when the PPS indicated leakage greater than the limits established in the Technical Specifications. A Steam Generator Blowdown (SGB) bellows failed due to a crack caused by TGSCC. Condensation of water from the PPS-supplied air inside the penetration wetted the pipe insulation and transported the chlorides contained in the insulation materials to the penetration bellows. The presence of the chlorides on the stainless steel material of the bellows caused the bellows to fail. Additional thermal stresses due to isolation of service water to the penetration coolers contributed to the event. The penetration bellows and endplates were removed on all the SGB bellows per a plant modification. The insulation was replaced with chloride free insulation. Pipe caps replaced the inside end plates. Based on a new design without bellows, the aging mechanism no longer exists for the SGB line penetrations. This was also documented in a Licensee Event Report (LER 95-005-00).

On October 7, 1996, a leak was found on the bellows inside the containment on penetration 63, sleeve 5. This was discovered during pressure testing of a new bellows installed on penetration 51, which is also on sleeve 5. It was found that the bellows convolutions had been compressed and damaged due to work performed on other bellows in the area during a previous outage. The penetration bellows was replaced in Refueling Outage-18. There were no aging mechanisms identified.

On March 24, 1997, a hole approximately ¼" in size was discovered on the bellows for sleeve 12 on penetration 59 inside the containment. This was discovered during local leak rate testing of mechanical penetration sleeves. The hole was determined to be the result of other work activities (welding arc strike), and was not an age-related failure.

RNP performed an evaluation of NRC IN 92-20, "Inadequate Local Leak Rate Testing." This IN discusses inadequate Type B local leak rate testing for two-ply stainless steel bellows. The evaluation of this IN at RNP was discussed in the RNP letter from B. L. Fletcher III (CP&L) to the NRC, Serial: RNP-RA/02-0086, dated June 19, 2002. Routine penetration sleeve leak rate testing is performed from outside the containment via test connections that are installed in the sleeve end plates, such that the entire sleeve, including bellows, is tested as one unit.

RAI 3.5.1-17

In discussing the AMR for the containment bellows in Item 2 of Table 3.5-1, the applicant states that the outside plate/bellows are tested by the Appendix J program alone as part of the local penetration pressurization test boundary and are not subjected to IWE aging management program. The applicant is requested to provide the following information in this context:

(a) Are the outside plate/bellows accessible for inspection?
(b) Is a penetration pressurization system installed at RNP which continuously monitors the leakage from the penetrations?

RNP Response:

(a) Outside plate/bellows are accessible for inspection. However, these plates/bellows are not part of the containment pressure boundary and are only used during testing.

(b) The penetration pressurization system (PPS) installed at RNP does not continuously monitor the leakage from the penetrations. The PPS is used during power operation to test the personnel airlock and during outages to test containment penetrations (local leak rate tests). The PPS was originally installed as a continuous monitoring system but the system was modified in 1995 to change to an intermittent monitoring system, and PPS was isolated to the containment penetrations. Refer to the RNP letter from R. M. Krich (CP&L) to NRC, Serial RNP-RA/95-0207: "Report of Changes Pursuant To 10 CFR 50.59," dated December 21, 1995.

RAI 3.5.1-18

In discussing the AMR for the containment seals and gaskets in Item 6 of Table 3.5-1, the applicant indicates that the leak tightness of seals and gaskets of containment penetrations is ensured by means of an Appendix J program. Performance based Option B of Appendix J (of 10 CFR 50) provides flexibility to the users of the option to perform type B tests at an interval as long as 10 years (except for the air-locks). Considering that some leakage is allowed during the type B tests (i.e., minor degradation is permissible), the applicant is requested to discuss how it will manage the degradation of penetration seals and gaskets between the test intervals during the extended period of operation (e.g., replacing seals and gaskets at intervals based on the operating experience, and or manufacturer's recommendations).

RNP Response:

RNP uses Option A of 10 CFR 50, Appendix J, for Type B testing (for gaskets and seals).

Type B tests are conducted on a refueling outage interval, not to exceed a maximum interval of two years with the following exceptions:

1. The containment air lock is tested at six-month intervals.
2. If the air lock is opened during periods when containment integrity is not required, it is tested at the end of such periods prior to restoring the reactor to an operating mode that requires containment integrity.
3. If the air lock is opened during periods when containment integrity is required, the door seals are tested within 3 days after being opened.

This current frequency of testing was evaluated to be adequate for the extended period of operation. Due to the short testing intervals, credit was not taken for additional inspections made as part of preventative maintenance. The Appendix J Program at RNP is consistent with GALL Section XI.S4, as discussed in LRA Appendix B, Item B.2.7.

RAI 3.5.1-19

In discussing the AMR for the moisture barriers in Item 6 and liner corrosion in Item 12 of Table 3.5-1, the applicant indicates that the moisture barriers will be inspected whenever the containment liner insulation is removed for maintenance work, and that the present conditions of the containment liner and the moisture barrier are acceptable until 2005. Provide a basis for concluding (1) the existing conditions of the containment liner (behind the moisture barrier) and the moisture barrier are acceptable, and (2) the inspection to be performed under a one-time inspection program will be sufficient to monitor the condition of containment liner behind the insulation and the moisture barrier during the extended period of operation.

RNP Response:

The RNP letter from B.L. Fletcher III (CP&L) to NRC, Serial RNP-RA/01-0125: "Submittal of 90 Day Inservice Inspection Summary Report," August 10, 2001, addresses the conclusions stated in the LRA.

Specifically, the existing condition of the containment liner (behind the moisture barrier) and the moisture barrier was determined to be acceptable based on visual examinations.

These visual examinations of the containment liner, behind the removed moisture barrier, determined that the corrosion observed did not impact the structural integrity or leak tightness of the containment. This examination did not include six areas that were either blocked by permanent structural features or in locations not available due to ALARA considerations. The liner plate areas with identified corrosion were prepared, recoated, and new moisture barrier installed. The six areas that were either blocked by permanent structural features or in locations not available due to ALARA considerations were considered to have the same environmental conditions as the areas that were examined. A worst case corrosion rate, as discussed in the RNP Response to RAI 3.5.1-7, was applied to the liner plate behind the moisture barrier. This resulted in the liner plate conservatively meeting the liner plate design thickness until year 2005.

In the six areas where the moisture barrier was not replaced, the moisture barrier material was assumed to be degraded. Engineering determined that degradation of the moisture barrier material in these six areas would not result in unacceptable degradation of the containment liner below the minimum design thickness. This was based on the successful examination and evaluation of the liner plate above the moisture barrier, which was determined to be acceptable for continued service until year 2005, as discussed above.

The inspection to be performed under the One-Time Inspection Program was determined to be sufficient to monitor the condition of the containment liner behind the insulation and the moisture barrier during the extended period of operation.

Liner plate areas (behind the moisture barrier) with identified corrosion will be prepared, recoated, and new moisture barrier installed. No additional examinations are planned beyond those required by the IWE Program.

In accordance with LRA Table 3.5-1, Items 6 and 12, the existing IWE Program is committed to for the extended period of operation, and the one-time inspection will be completed before the end of 2005.

RAI 3.5.1-20

In discussing the AMR for the prestressed containment tendons and anchorage components in Item 11 and 14 of Table 3.5-1, the applicant indicates that the evaluation is consistent with the GALL Report, and the inspections of sample surveillance blocks at 5 and 25 years have determined that the grouting has proven to be an effective means for preventing corrosion of the tendons and anchorage components.

Neither the GALL report nor Subsection IWL address inspection or monitoring of grouted tendons. The aging effect due to loss of material from corrosion of the grouted tendons and their anchorage is the concern. The surveillance blocks may provide some evidences of potential corrosion. For that reason, the applicant is requested to provide the following information regarding the two surveillance blocks (SBs):

(a) What was the environment in which the SBs were cast (sheltered, unsheltered, year round temperature, humidity, etc.)?
(b) Were the tendons in the SBs the same size as those in the containment?
(c) Were they prestressed to the same level as the tendons in the containment?
(d) Were the blocks instrumented for time-dependant stress/strain measurements?
(e) Provide a summary of the condition of the bars and the grout when the SBs were dismantled at 5 and 25 years (if photographs are available, please provide photographs.).

RNP Response:

Item 11 of LRA Table 3.5-1 is associated with GALL Item A1.3-b and the subject GALL item does not identify the prestressing system as either grouted or un-grouted. It does, however, identify the loss of prestress as a TLAA requiring further evaluation, which is how Item 11, from LRA Table 3.5-1 was classified and evaluated.

Item 14 of LRA Table 3.5-1 is associated with GALL Item A1.3-a, the discussion associated with Item 14 states the Containment ISI Program is "not applicable." Because Subsection IWL requires examination and testing of unbonded post-tensioning systems only, the grouted post-tensioning system at RNP is not subject to ASME Section XI rules.

The following information is providing the surveillance block:

a) The surveillance tendons consist of six 1-3/8 inch diameter bars grouted in a six inch pipe sheath with anchor plates, prestressing hardware, which is identical to the service tendon except for the length. They are embedded in a section of concrete approximating the same environment as that of the service tendons. The surveillance blocks were placed next to the containment to subject them to a similar unsheltered outdoor environment.

b) The surveillance tendons are 1-3/8 inches in diameter which is the same size as the tendons used in the containment structure.

c) There are no records that would indicate the surveillance block tendons were prestressed. However, inspection results from the surveillance note a snap-back of the tendons into the casing as each rod was severed. The test lab suggested that the snap-back indicated a level of stress had been maintained in the rods by the grout.

d) The surveillance blocks were not instrumented for time-dependant stress/strain measurements.

e) The conclusions for both the 5 and 25 year surveillance blocks indicate there is no significant corrosion, and mechanical testing of the tendon bars also show no significant change in properties. While no specific inspection criteria was provided for the grout, it was noted that the grout cracked as the pipe was cut and stress relieved from the bars, Also in some areas, separated grout had a reddish-brown stain at the contact surface with the bars that was suspected to be an oxide that formed during construction.

The RNP letter from T. M. Wilkerson (CP&L) to the NRC, Serial RNP-RA/98-0012, dated February 4, 1998, included the 25 Year containment surveillance tendon test results along with photographs.

RNP letter from E. E. Utley (CP&L) to Edson G. Case (NRC), Serial NG-77-1018, dated September 9, 1977, included the 5 year surveillance tendon test results along with photographs.

RAI 3.5.1-21

Items 7 and 8 of Table 3.5-2 of the LRA identify change in material properties due to elevated temperature and cracking due to elevated temperature for elastomers. Please indicate whether the aging effects of cracking and change in material properties due to ultraviolet radiation and ionizing radiation will also be managed for elastomers.

RNP Response:

The aging effects of cracking and change in material properties due to ultraviolet radiation and ionizing radiation were determined to not be applicable based on industry guidance. The aging effects for ionizing radiation are applicable if integrated exposure is greater than 10^6 rads. None of the applicable elastomers were located in ionizing radiation fields where the integrated exposure over 60 years would be greater than 10^6 rads. The aging effects of ultraviolet radiation are applicable only if the materials are rubber. None of the elastomers identified at RNP are rubber.

RAI 3.6.1-1

In the LRA Section 3.6.2.1, the applicant states that the components of Non-EQ Electrical Penetration Assemblies subject to aging management review are the organic materials associated with electrical conductors and connections. It is not clear to the staff why the epoxy seal and other insulating material associated with the Electrical Penetration Assemblies do not require an aging management review.

RNP Response:

Electrical penetration assemblies are used to pass electrical circuits through the Containment wall while maintaining containment integrity. They provide electrical continuity for the circuit, as well as a pressure boundary for the containment. The pressure boundary function of electrical penetration assemblies is addressed in LRA Table 2.4-1. The intent of the electrical aging management review of electrical penetration assemblies is to preserve the assemblies' electrical continuity function. The focus of this review is the interaction between the assemblies' organic insulating materials and their operating environment. The organic insulating materials comprise the penetration assemblies' primary insulation system. In addition to organic insulating materials, there are other materials (metals and inorganic materials) used in the construction of the penetration assembly. These include cable fillers, epoxies, potting compounds, connector pins, plugs, and facial grommets. Consistent with the DOE/Sandia Aging Management Guideline (i.e., SAND 96-0344) these items have no significant effect on the normal aging process of primary insulation system and do not adversely affect the electrical continuity function. Accordingly, they are not included in aging management review of electrical penetration assemblies.

A detailed explanation of the 600V low power electrical penetration assemblies is provided below:

Each penetration consists of a stainless steel canister with a header plate at each end. Conductors pass through and are soldered to ceramic feedthroughs, which are welded to the header plate. This configuration provides the containment pressure seal and fission product barrier. Silicone rubber potting (i.e., GE RTV 615) covers the ceramic feedthrough/header plate interface. The internal conductors are insulated with either silicon rubber or Kerite. The outboard conductors are reinsulated with a silicone rubber sleeve (i.e., Varflex HA-1) and butt spliced to another section of cable (~ 6' in length) to form penetration pigtails. The individual pigtail cable butt splices are insulated with Raychem WCSF-N heat shrink tubing. An epoxy potting compound (i.e., Stycast CPC-9 manufactured by Emerson & Cuming) holds the outboard conductors in place, provides the necessary strain relief and prevents foreign material from contaminating the primary insulating system of the penetration assembly. This potting compound is not part of the primary insulating system and, as such, is not included in the review of assemblies' insulation materials. A sacrificial phenolic spacer disk[1] is installed over the epoxy potting compound to exclude dirt and prevent physical damage to the epoxy. The pigtails on the penetration assemblies were either provided by Ebasco to Crouse-Hinds or purchased by Crouse-Hinds using Ebasco penetration specifications. The Ebasco penetration specification requires the use of either silicon rubber, Kerite, or PVC insulation for the pigtails, depending on their plant application. The penetration pigtails are subsequently spliced to a field cable using either a compression connector or plug-in connector, again depending on their plant application. Compression connections are covered with Raychem WCSF-N heat shrink tubing. Raychem heat shrink tubing splice kits (e.g., WCSF-N, and others) are made of cross-linked polyethylene (XLPE). The 600V low power penetration assembly organic insulation materials are summarized in Table 1 below. It should be noted that only the primary insulation materials of the penetration assembly are shown, since items such as epoxy potting compounds, phenolic spacers, etc. have no significant effect on the normal aging process of primary insulation system and do not warrant aging management review.

TABLE 1 • RNP NON-EQ 600V LOW POWER AND I&C PENETRATION ASSEMBLY INSULATION MATERIALS

Material	Application
SR	Internal conductor insulation, pigtail insulation, potting, sleeving
PVC	Pigtail insulation
Kerite	Internal conductor insulation, pigtail insulation
XLPE	Splices and connections

1 During initial fabrication of the penetration assemblies the phenolic spacer disk was installed to hold the conductors in place while the epoxy compound cured. Since this disk is not part of the penetration assemblies primary insulation system, it will not be included in the review of penetration insulation materials.

RAI 3.6.1-2

The aging management activity (Table 3.6-1 Item 3 and Table 3.6-2 Item 2 of LRA) submitted by the applicant does not utilize the calibration approach for non-EQ electrical cables used in circuits with sensitive, low level signals. Instead, these cables are simply combined with all other non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone would not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to localized environments caused by heat, radiation, or moisture can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. 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.

The staff is not convinced that aging of these cables will initially occur on the outer jacket resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss of its intended function, particularly if the cables are also subject to moisture. Therefore, please provide a technical justification that will demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy.

RNP Response:

RNP will implement aging management programs to manage the aging effects of high-range radiation and neutron flux instrumentation circuits. Table 1 shows the aging management review results for the RNP high-range radiation and neutron flux instrumentation circuits.

These are two (2) separate but related programs. Attachment 1 shows the details of the aging management program for high-range radiation monitoring instrumentation circuits. The aging management program for the high-range radiation monitoring instrumentation circuits is consistent with the Non-EQ Electrical Cables Used in Instrumentation Circuits Program presented in the GALL Report, Volume 2, Section XI.E2. As this cable monitoring program is modeled after the GALL Report, it is concluded that the requirements of 10 CFR 54.21(a)(3) have been met.

Neutron flux monitoring instrumentation cables that may experience a reduction in insulation resistance (IR) require a different program other than the one presented in the GALL Report, Volume 2, Section XI.E2, since these cables are disconnected from their circuits during calibration. Attachment 2 shows the details of the aging management program for neutron flux instrumentation circuits. The scope of the program includes those cables associated with the source range, intermediate range, power range, and gamma-metrics circuits of the excore nuclear instrumentation system.

Attachment 3 shows the program updates to UFSAR Supplement, Appendix A. It should be noted that reference to IR sensitive cables was removed from the program description for LRA Section A.3.1.33, as IR sensitive cables are now covered in the new programs described in LRA Section A.3.1.34 and A.3.1.35.

Table 1 – Aging Management Review Results for the High-Range Radiation and Neutron Flux Instrumentation Circuits

Component/ Commodity	Materials of Construction	Environment (1)	Aging Effect/ Mechanism	Aging Management Program	Discussion
High-Range Radiation Monitoring Instrumentation Circuits	Various Organic Polymers	Indoor – Air Conditioned Indoor – Not Air Conditioned	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	RNP will implement an Aging Management Program for High-Range Radiation Monitoring Instrumentation Circuits. The scope of the program is limited to the cables associated with the CV High Range Monitors. The Aging Management Program for the high-range radiation monitoring circuits is consistent with the GALL XI.E2 Program. In this aging management program, calibration results or findings of surveillance testing programs are used to identify the potential existence of aging degradation.
Neutron Flux Instrumentation Circuits	Various Organic Polymers	Indoor – Air Conditioned Indoor – Not Air Conditioned	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging Management Program for Neutron Flux Instrumentation Circuits	RNP will implement an Aging Management Program for Neutron Flux Instrumentation Circuits. The scope of the program is limited to the cables associated with the Source Range, Intermediate Range, Power Range, and Gamma-Metrics circuits of the Excore Nuclear Instrumentation System (NIS). In this aging management program, an appropriate test, such as insulation resistance tests, time domain reflectometry (TDR) tests, or I/V testing will be used to identify the potential existence of a reduction in cable IR.

Attachment 1 – Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits

Exposure of electrical cables to adverse localized environments caused by heat, radiation or moisture can result in reduced insulation resistance (IR). 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 circuit. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. 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 instrument circuits.

The purpose of the aging management program described herein is to provide reasonable assurance that the intended function of radiation monitoring instrumentation circuits exposed to an adverse localized environment caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation.

In this aging management program, calibration results or findings of surveillance testing programs are used to identify the potential existence of aging degradation. For example, when an instrumentation circuit is found to be out of calibration, additional evaluation of the circuit is performed. GALL AMP XI.E1 does not apply to the cables in these instrumentation circuits.

Scope of Program
This program applies to the non-EQ cables used in CV high-range radiation monitoring instrumentation circuits.

Preventive Actions
No actions are taken as part of this program to prevent or mitigate aging degradation.

Parameters Monitored or Inspected
The parameters monitored are determined from the specific calibrations or surveillances performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant surveillance calibration or surveillance procedures.

Detection of Aging Effects
Review of calibration results or findings of surveillance programs can provide indication of aging effects by monitoring key parameters and providing data based on acceptance criteria related to instrumentation circuit performance. Reviews of results obtained during normal calibrations or surveillances may detect severe aging degradation prior to loss of cable intended function. The first reviews will be completed before the end of the initial 40-year license term for

Unit 2 (July 31, 2010) and every 10 years thereafter. All calibrations or surveillances that fail to meet acceptance criteria will be reviewed at the time.

Monitoring and Trending
Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the Unit 2 FSAR is part of the RNP Quality Assurance (QA) Program.

Acceptance Criteria
Calibration results or findings of surveillances are to be within the acceptance criteria, as set out in the calibration or surveillance procedure.

Corrective Actions
Corrective actions such as recalibration and circuit trouble-shooting are implemented when calibration results or findings of surveillances do not meet the acceptance criteria. Corrective actions (as required) are implemented through the RNP Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Confirmation Process
The RNP Corrective Action Program will verify the effectiveness of corrective actions (as required). The confirmation process is considered an integral part of the Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Administrative Controls
This program is implemented by surveillance test procedures as required by Plant Technical Specifications. The administrative controls for these procedures are controlled by the Document Control Program. The Document Control Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Operating Experience
Changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation.

Attachment 2 – Aging Management Program for Neutron Flux Instrumentation Circuits

Exposure of electrical cables to adverse localized environments caused by heat, radiation or moisture can result in reduced insulation resistance (IR). 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 circuit. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. 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.

The purpose of the aging management program described herein is to provide reasonable assurance that the intended function of neutron flux instrumentation circuits exposed to an adverse localized environment caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation.

In this aging management program, an appropriate test, such as insulation resistance tests, time domain reflectometry (TDR) tests, or I/V testing will be used to identify the potential existence of a reduction in cable IR. GALL AMP XI.E1 does not apply to the cables in these instrumentation circuits.

Scope of Program
This program applies to the non-EQ cables used in the Source Range, Intermediate Range, Power Range, and Gamma-Metrics instrumentation circuits of the Excore Nuclear Instrumentation System (NIS).

Preventive Actions
No actions are taken as part of this program to prevent or mitigate aging degradation.

Parameters Monitored or Inspected
The parameters monitored include a loss of dielectric strength caused by thermal/ thermoxidative degradation of organics or radiation-induced oxidation (radiolysis) of organics.

Detection of Aging Effects
The cables used in neutron flux instrumentation circuits will be tested at least once every 10 years. Testing may include insulation resistance tests, TDR tests, I/V testing, or other testing judged to be effective in determining cable insulation condition. Following issuance of a renewed operating license for RNP, the initial test will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010).

Monitoring and Trending
Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the Unit 2 FSAR is part of the RNP Quality Assurance (QA) Program.

Acceptance Criteria
The acceptance criteria will be determined based on the test selected for this program.

Corrective Actions
Corrective actions (as required) are implemented through the RNP Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Confirmation Process
The RNP Corrective Action Program will verify the effectiveness of corrective actions (as required). The confirmation process is considered an integral part of the Corrective Action Program. The Corrective Action Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Administrative Controls
This program will be controlled by the Work Control Process. The administrative controls for the Work Control Process are controlled by the Document Control Program. The Document Control Program is implemented by the RNP QA Program in accordance with 10 CFR 50, Appendix B.

Operating Experience
The vast majority of site specific and industry wide operating experience (OE) is related to cable/connector issues inside Containment near the Reactor Vessel. There is comparatively far less OE in the other more benign areas of the plant.

A.3.1.33 Non-EQ Insulated Cables and Connections Program

The Non-EQ Insulated Cables and Connections Program is credited for aging management of cables and connections not included in the RNP EQ Program. The non-EQ insulated cables and connections managed by this program include those used in power, instrumentation, control and communication applications. The program involves periodic, visual inspections of accessible cables and connections installed in adverse localized environments to detect embrittlement, cracking, melting, discoloration or swelling that could lead to reduced insulation resistance or electrical failure. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service condition for the electrical cable or connection.

A.3.1.34 Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits

In this aging management program, calibration results or findings of surveillance testing programs are used to identify the potential existence of aging degradation. Exposure of electrical cables to adverse localized environments caused by heat, radiation or moisture can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. 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. This program applies to the cables used in CV high-range radiation monitoring instrumentation circuits.

A.3.1.35 Aging Management Program for Neutron Flux Instrumentation Circuits

In this aging management program, an appropriate test, such as insulation resistance tests, time domain reflectometry (TDR) tests, or I/V testing will be used to identify the potential existence of a reduction in cable insulation resistance (IR). Exposure of electrical cables to adverse localized environments caused by heat, radiation or moisture can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. 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. This program applies to the cables used for the Source Range, Intermediate Range, Power Range, and Gamma.-Metrics circuits of the Excore Nuclear Instrumentation System (NIS).

RAI 3.6.1-3

Item 3 of Table 3.6-1, the last sentence under Discussion states that "Additional information is provided in Table 3.6-2, Item 3." Table 3.6-2 contains two Items only. Please clarify.

RNP Response:

This is a typographical error. The last sentence under Discussion should read "Additional information is provided in Table 3.6-2, Item 2."

RAI 3.6.1-4

Item 4 of Table 3.6-1, under discussion, the applicant states that no AMP is required for inaccessible medium-voltage (2kV to 15kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements. The applicant determined that no medium voltage cables, that are potentially susceptible to wetting, provide any license renewal intended function. The staff believes that some circuits (e.g., service water pumps) will be susceptible to wetting and hence an AMP is necessary. Please identify cables that are installed in conduits or direct buried and explain how the aging due to wetting will be managed

RNP Response:

Energized medium-voltage cables are subject to a phenomenon known as water treeing which can ultimately result in failure of the cable insulation. For the purposes of license renewal, medium voltage is defined as 2 KV to 15 KV. According to the DOE/Sandia Aging Management Guideline (SAND 96-0344), the incidence of cable failure due to water treeing has been found to be more prevalent as voltage level increases. RNP evaluated all energized medium voltage circuits to determine which components in-scope for license renewal were fed by cables that were direct buried, in underground conduits, or in duct banks. This review found that there were no in-scope energized and wetted medium voltage cables at RNP. This aging mechanism has not been observed in low voltage cables, which are defined as cables rated at less than 2 KV.

The service water pumps are located at the intake structure and are rated at 480 VAC, which is considered low voltage. The cables feeding these pumps are direct buried, normally energized and wetted. However, no aging mechanism has been identified for low voltage, energized and wetted cables.

This conclusion was based on review of internal and external operating experience (OE) and review of industry literature on aging mechanisms for cable. The specific cables mentioned by the NRC staff (that is, service water pumps) are classified as direct buried, PVC-insulated and jacketed, low-voltage cables with a Conductor Temperature Rating of 75°C. The industry standard that mandates the construction details for PVC-insulated cables is ICEA Publication No. S-61-402. The average insulation thickness for the cables connected to the service water pump motors must be 95 mils, and the average jacket thickness must be 65 mils. According to Section 3.8 of ICEA S-61-402, this insulation is suitable for use at conductor temperatures not exceeding 75°C (167°F) "in dry or wet locations." Also, the overall PVC jacket prevents moisture from contacting the primary cable insulation.

The effects of moisture on low-voltage cables is not a concern of the cable industry itself. A comprehensive review of wetting of low-voltage cables was performed by EPRI in 1994[2] Page 2.4-7 of that report states the following:

> "As part of this study, a literature review was undertaken to identify current information on the effects of moisture on low-voltage cables. It soon became evident that there were literally hundreds of papers on water-treeing in higher voltage cables and on the subject of liquid and vapor uptake and transport in polymers. However, information on the effects of prolonged moisture exposure on the performance of low-voltage cables was virtually nonexistent. Furthermore, most of the information identified was typically 30 years or older. One could concluded that the absence of technical papers on moisture effects in low-voltage cables suggest that significant degradation mechanisms do not exist for typical plant conditions or that low priority has been assigned to such efforts."

The DOE/Sandia Aging Management Guideline (AMG) reviewed the causes for all cable failures reported in the NPRDS and LERs. Failure from moisture intrusion was listed for only 10 cables. Aging caused by wetting does not appear as a cause for any failure. Conversely, Section 4.1.2.4 of the AMG specifically states the following: "PVC is an example of a jacketing material commonly used in high moisture applications to help prevent radial ingress of moisture to the underlying insulation."

Based on the above discussion, RNP has found no aging mechanism associated with wetted low-voltage energized cables and, therefore, no aging management program is warranted. This finding is consistent with available industry operating experience, cable aging literature, and prior license renewal applicants.

---

2 TR-103834-P1-2, "Effects of Moisture on the life of Power Plant Cables," August 1994, Electric Power Research Institute

RAI 4.1-1

10 CFR 54.21(c) requires an evaluation of time-limited aging analyses (TLAA) be provided as part of the LRA. The LRA for RNP indicates that TLAAs are defined by the six criteria of 10 CFR 54.3 and the RNP-specific TLAA is consistent with the guidance provided in NEI 95-10. Table 4.1-1 of the LRA provides the results of 10 CFR 54.21(c)(1) evaluation and identifies TLAAs applicable to RNP. NUREG-1800 was used by other applicants as a source to identify potential TLAAs. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other LRAs. For those TLAAs listed in Tables 4.1-2 and 4.1-3 of NUREG-1800, that are applicable to PWR facilities and not included in Table 4.1-1 of the LRA, please discuss whether you have performed any calculations or analyses that address these topics at RNP. If calculations or analyses exist that address these topics, please discuss how these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 54.3.

RNP Response:

During the search for RNP-specific time-limited aging analyses, calculations and evaluations that could potentially meet the six criteria of 10 CFR 54.3 were identified by searches of current licensing basis documents, including the Technical Specifications, UFSAR, docketed correspondence, applicable Westinghouse WCAP's, plant evaluations, calculations, and other documents. Industry-prepared documents that list generic time-limited aging analyses were also reviewed to provide guidance for focused searches for specific analysis categories. This provided additional assurance that the list of potential TLAA's was complete. These documents included NUREG-1800 and the submittals of other license renewal applicants.

TLAAs listed in Tables 4.1-2 and 4.1-3 of NUREG-1800 that are applicable to PWR facilities and not included in Table 4.1-1 of the LRA are: inservice flaw growth analysis of structure stability, metal containment corrosion allowance, high energy line break analysis based on cumulative usage factor, reactor vessel low temperature overpressure protection (LTOP) analysis, main steam supply lines to AFW pump, RCP flywheel fatigue analysis, reactor vessel internals transient analysis, reactor vessel internals fracture toughness ductility reduction, and containment liner plate fatigue analysis. There are no high energy line break analyses for RNP that rely on fatigue cumulative usage values, such as those in Regulatory Guide 1.46, to identify potential break locations.

Based on the results of the search for RNP-specific TLAAs summarized above, the calculations or analyses that were identified for these generic TLAA categories, include the reactor vessel for LTOP analysis, the main steam supply lines to AFW pump, and the RCP flywheel fatigue analysis. The analysis of the main steam supply lines to the AFW pump is addressed in LRA Subsection 4.3.2, Implicit Fatigue Design (ASME Section III, Class C, B31.1). No explicit fatigue analysis of the main steam supply lines to the steam-driven AFW pump has been identified for RNP. The other two potential TLAAs were determined to not meet the criterion from 10 CFR 54.3 that the analysis involves time-limited assumptions defined by the current operating term. The RNP LTOP analyses have been performed for periods less than the current operating term and are periodically updated. Refer to the RNP Response to RAI 4.2.3-1, Part 2, for further discussion on this matter. The RCP flywheel fatigue analysis has been performed using an operating life of 60 years.

RAI 4.2.1-1

Pursuant to 10 CFR 54.21(c)(1)(ii), in order to demonstrate that the time-limited-aging analysis (TLAA) for protecting RNP reactor vessel (RV) against pressurized thermal shock (PTS) events, as summarized in Section 4.2.1 of the license renewal application (LRA), has been projected through the expiration of the extended period of operation and remains in compliance with the requirements of 10 CFR 50.61, provide your calculations of the RT_{PTS} values for all base-metal and weld materials in the RNP RV beltline shells and nozzles, as evaluated through the extended period of operation for RNP. Include in calculations the following Items:

1. Please identify the methodology used in the calculation of the projected 60-year neutron fluence values for the beltline materials, including the parameters and approximations used in the calculation methods. State whether the methodology adheres to the guidance of Regulatory Guide (RG) 1.190. For each RV beltline material, provide the inside-RV-surface neutron fluence value used in the RT_{PTS} calculation at expiration of the period of extended operation.

2. Provide any changes, as applicable, to the baseline $RT_{NDT(u)}$ values (initial RT_{NDT} values) for the beltline materials.

3. Provide the quantitative impacts of applicable RV materials surveillance data, to date, that are relevant to the RT_{PTS} calculations for the base-metal and weld materials used to fabricate the RNP RV beltline shells and beltline nozzles.

4. Provide, as applicable, the relevant PTS data and RT_{PTS} calculations for any additional ferritic (i.e., carbon steel of low-alloy steel) RV materials whose projected 40-year (current operating term) neutron fluence is below the threshold of $1x10^{17}$ n/cm^2 for neutron irradiation embrittlement but whose projected 60-year, end-of-extended-operating-term neutron fluences are projected to exceed this threshold during the period of extended operation for RNP.

5. Confirm that the fracture toughness and dosimetry data for testing surveillance capsule X, which were recently reported to the NRC by CP&L letter of April 25, 2002, have been incorporated into the requested calculations of the RT_{PTS} values for the RNP beltline materials.

RNP Response:

The TLAAs associated with pressurized thermal shock (PTS) have been projected for 60 years pursuant to 10 CFR 54.21(c)(1)(ii). Calculations have been performed in compliance with the requirements of 10 CFR 50.61 to ensure that the RNP reactor vessel (RV) beltline plates, nozzle materials, and their associated weld materials will have adequate resistance to PTS throughout the period of extended operation. Updated PTS calculations applicable for 60 years of operation (50 EFPY) are included in WCAP-15828, "Evaluation of Pressurized Thermal Shock for H. B. Robinson Unit 2," Rev. 0, which was prepared subsequent to the LRA.

1. The most recent surveillance test results for Capsule X were documented in WCAP-15805, Rev.0, which was submitted to the NRC in April 2002. WCAP-15828, Rev. 0, uses 60-year neutron fluence values for the beltline materials that comply with Regulatory Guide 1.190. The fluence values were projected using ENDF/B-VI cross sections based on the results of the Capsule X radiation analysis. Note that the fluence projections were obtained from Section 6.0 of WCAP-15805 and were updated to reflect the actual power realized from the Refueling Outage (RO)-21 power uprate.

   Neutron fluence methodology is discussed in Section 5 of WCAP 15828, Rev. 0. The following table provides the 29 EFPY (40-year) and 50 EFPY (60-year) fluence values applicable for the clad/base metal interface for each component in the beltline region, including nozzles and nozzle welds.

Calculated Fluence (E > 1.0 MeV) on the Pressure Vessel Clad/Base Interface for Robinson Nuclear Plant at 29 (EOL) and 50 (Life Extension) EFPY

Material	Location	29 EFPY Fluence (n/cm^2, E > 1.0 MeV)	50 EFPY Fluence (n/cm^2, E > 1.0 MeV)
Intermediate Shell Plates	0°	3.68×10^{19}	6.01×10^{19}
Upper to Intermediate Shell Circumferential Weld & Upper Shell Plates[a]	0°	1.57×10^{19}	2.50×10^{19}
Intermediate to Lower Circumferential Weld & Lower Shell Plates[a]	0°	1.67×10^{19}	2.05×10^{19}
Intermediate Shell Longitudinal Welds, Lower Shell Longitudinal Welds and Upper Shell Longitudinal Welds[b]	10°, 20° or 40°[c]	2.73×10^{19}	4.46×10^{19}
Inlet Nozzle	Peak	2.19×10^{17}	3.49×10^{17}
Outlet Nozzle	Peak	1.21×10^{17}	1.92×10^{17}
Inlet Nozzle Weld	Peak	2.47×10^{17}	3.93×10^{17}
Outlet Nozzle Weld	Peak	1.59×10^{17}	2.53×10^{17}

Notes:

(a) The fluence used is the peak fluence on the given circumferential welds and applied to their respective shell plates above or below the weld.

(b) For conservatism, the peak fluence on the intermediate shell longitudinal welds was applied to the upper and lower shell longitudinal welds. This was done because they are the same heat of weld, and the intermediate shell is therefore the limiting of the three sets.

(c) The fluence was taken from the peak azimuthal location from the three provided.

2. $RT_{NDT(U)}$ values incorporating the results of Surveillance Capsule X are provided in Table 7 of WCAP-15828, Rev. 0.

3. WCAP-15828, Rev. 0, provides an evaluation of PTS for Robinson Nuclear Plant that incorporates the results of the surveillance Capsule X evaluation. WCAP-15828, Rev. 0, incorporates applicable RV materials surveillance data that are relevant to the updated RT_{PTS} calculations for the base-metal and weld materials used to fabricate the RNP RV beltline shells and beltline nozzles.

   The calculated RT_{PTS} temperatures for reactor vessel beltline materials, including plates, forgings, axial welds, inlet nozzles, outlet nozzles, and nozzle welds have been demonstrated to remain below the 270°F PTS screening criterion throughout the 60-year period of extended operation. The limiting location is Upper Shell Plate W10201-2, which has an RT_{PTS} temperature of 182°F.

The calculated RT_{PTS} temperatures for circumferential welds have been demonstrated to remain below the 300°F PTS screening criterion throughout the 60-year period of extended operation. The limiting location is Circumferential Weld Seam 10-273, which has an RT_{PTS} temperature of 297°F.

4. The inlet and outlet nozzles and adjoining nozzle welds are also evaluated in WCAP-15828, Rev. 0, and are projected to exceed a fluence of $1x10^{17}$ n/cm^2 during the extended license period. The highest RT_{PTS} temperature for the nozzles is 118°F, and is 71°F for nozzle welds. Therefore, the nozzles and nozzle welds have been demonstrated to remain below the 270°F PTS screening criterion throughout the 60-year period of extended operation. They have also been shown not to be the limiting components, since beltline materials are closer to the limit. Therefore, the inlet and outlet nozzles and welds need not be added to the Reactor Vessel Surveillance Program.

5. The fracture toughness and dosimetry data for testing surveillance Capsule X have been incorporated into the calculations of the RT_{PTS} values for the RNP beltline materials, as provided in WCAP-15828, Rev. 0.

RAI 4.2.2-1 PARTS 1 AND 2

Part 1: Pursuant to 10 CFR 54.21(c)(1)(ii), in order to demonstrate that the time-limited-aging analysis (TLAA) for ensuring that the RNP beltline reactor vessel (RV) materials will have adequate values of USE and will remain in compliance with the requirements of Section IV.A.1 of 10 CFR Part 50, Appendix G, as projected through the expiration of the extended period of operation for RNP, provide your calculations of the USE values for all beltline base-metal and nozzle materials and their associated welds materials, as evaluated through the extended period of operation for RNP. Include in calculations the following Items:

1. Provide the projected 60-year neutron fluence values at the 1/4T location of the RV for the all RNP beltline shell and nozzle materials, and their associated welds, as projected through the extended period of operation for RNP under the conditions identified in RAI 4.2.2.1-1.

2. Provide any changes, as applicable, to baseline unirradiated USE values for the beltline materials.

3. Provide the quantitative impacts of applicable RV materials surveillance data, to date, that are relevant to the USE values calculations for the base-metal and weld materials used to fabricate the RNP RV beltline shells and beltline nozzles.

4. Provide, as applicable, the relevant USE data and calculations for any additional ferritic (i.e., carbon steel of low-alloy steel) RV materials whose projected 40-year (current operating term) neutron fluence is below the threshold of $1x10^{17}$ n/cm^2 for neutron irradiation embrittlement but whose projected 60-year, end-of-extended-operating-term neutron fluences are projected to exceed this threshold during the period of extended operation for RNP.

5. Confirm that the fracture toughness and dosimetry data for testing surveillance capsule X, which were recently reported to the NRC by CP&L letter of April 25, 2002, have been incorporated into the requested calculations of the USE values and appropriate EMA analyses for the RNP RV beltline materials.

Part 2: Section IV.A.1 of 10 CFR Part 50, Appendix G, requires that equivalent margins analyses (EMAs) for USE be approved by the Director of the Office of Nuclear Reactor Regulation, or his/her designee. The staff approved the analysis in WCAP-13587, Revision 1, by letter to CP&L dated September 19, 1994. In RAI 4.2.2.2-1, Part 1, the staff requests the updated end-of-extended operating period (60-year) 1/4T fluences for the RNP reactor vessel (RV) beltline materials. Reassess the EMA analysis in WCAP-13587, Revision 1, and provide your technical basis to demonstrate that the EMA analysis in WCAP-13587, Revision 1, remains bounding for RV shell plates W10201-1, W10201-3, and W10201-4 through 60 years of licensed operation of the reactor (i.e., for the 1/4T fluences projected for the plates at the end of the extended period of operation for RNP). Pursuant to 10 CFR 54.21(c)(1), you will be required to submit revised EMA analyses for the RNP RV, if the WCAP-13587, Revision 1, EMA analyses for RV shell plates W10201-1, W10201-3, and W10201-4 are not determined to be bounding based on the projected for the 60-year 1/4T fluences for the plates, or if any other RNP RV beltline materials are projected to have USE values below 50 ft-lbs through the expiration of the extended period of operation for RNP.

RNP Response:

Part 1:

Calculations have been performed in compliance with Section IV.A.1 of 10 CFR Part 50, Appendix G to ensure that the RNP reactor vessel (RV) beltline plates and nozzle materials and their associated weld materials will have adequate values of Upper Shelf Energy (USE) through the period of extended operation. The USE calculations applicable for 60 years of operation (50 EFPY) are included in WCAP-15828, "Evaluation of Pressurized Thermal Shock for H.B. Robinson Unit 2," Rev. 0.

1. Refer to the RNP Response to RAI 4.2.1-1

2. The RNP unirradiated USE values for the beltline materials are provided in Table 1 of WCAP-15828, Rev. 0.

3. WCAP-15828, Rev. 0, incorporates the applicable RV materials surveillance data, available to date, that are relevant to the updated USE calculations for the base-metal and weld materials used to fabricate the RNP RV beltline shells and beltline nozzles. The most recent surveillance test results for Capsule X were submitted to the NRC in April, 2002 (WCAP-15805). WCAP-15828, Rev. 0, Appendix A, provides an evaluation of USE for the Robinson Nuclear Plant incorporating the results of the surveillance Capsule X evaluation.

   WCAP-15828, Appendix A, Table A-3, provides predicted end-of-extended-license (50 EFPY) USE values for the beltline region materials. The limiting value is for Upper Shell Plate W 10201-3, which has a predicted 60-year USE of 48.4 ft-lbs. This exceeds the applicable 42 ft-lbs minimum requirement from the Equivalent Margins Analysis provided in WCAP-13587, Rev. 1, for this material. Other beltline region materials are predicted to exceed the applicable 50 ft-lbs minimum acceptance criterion. Therefore, each of the materials has been shown to be suitable for use throughout the period of extended operation with respect to loss of fracture toughness.

4. The inlet and outlet nozzles and adjoining nozzle welds are also evaluated in WCAP-15828, Rev. 0, and are projected to exceed a fluence of $1x10^{17} n/cm^{2}$ during the extended license period. Table A-4 of WCAP-15828 provides predicted end-of-extended-license (50 EFPY) USE values for the nozzles and nozzle welds. The limiting value predicted for the nozzles is 63 ft-lbs and the limiting value predicted for the nozzle welds is 55 ft-lbs. Each of these values exceed the applicable 50 ft-lbs minimum acceptance criterion. Therefore, each of the nozzle and weld materials has been shown to be suitable for use throughout the period of extended operation with respect to loss of fracture toughness. Neither value is limiting, so neither the nozzles, nor the nozzle welds, must be added to the surveillance program.

5. The fracture toughness and dosimetry data for testing surveillance Capsule X have been incorporated into the calculations of the USE values for the RNP beltline materials, as provided in WCAP-15828, Rev. 0. Note that the fluence projections were obtained from Section 6.0 of WCAP-15805 (Capsule X analysis report) and were updated to reflect the actual power realized from the RO-21 power uprate.

PART 2:

Refer to RAI 4.2.1-1 for the 60 year 1/4T fluences for the RNP Reactor Vessel Beltline materials.

Revision 1 of WCAP-13587 provided a bounding EMA for WOG plants and has been previously reviewed and approved by the NRC staff. This analysis showes that an equivalent margin of safety exists for reactor vessel components with USE values of 42 ft-lbs or more. Each of the projected 60-year USE values applicable for RNP exceed this 42 ft-lbs value. Therefore, the EMA analysis in WCAP-13587, Rev. 1, remains bounding for RNP beltline materials through 60 years of licensed operation, and no revision to the EMA is required.

RAI 4.2.2.3-1

In all previous applications, the NRC has categorized the pressure-temperature (P-T) limits and low pressure overpressure protection (LTOP) limits for operating light-water reactors as time-limited aging analyses (TLAAs) that fall within the scope of 10 CFR 54.3(a). Confirm that the P-T limits and LTOP limits for RNP are TLAAs in accordance with definition for TLAAs in 10 CFR 54.3(a).

RNP Response:

The P-T limits and LTOP limits at RNP are not TLAAs.

Time-limited aging analyses are defined in 10 CFR 54.3(a) as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
(2) Consider the effects of aging;
(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
(4) Were determined to be relevant by the licensee in making a safety determination;
(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and
(6) Are contained or incorporated by reference in the current licensing basis.

For an analysis to be a TLAA, it must satisfy all six criteria.

The P-T limits and LTOP limits were evaluated as potential TLAA's for RNP and were therefore evaluated against the six criteria specified above. The current P-T curves and LTOP limits are valid up to 23.96 EFPY which is less than the 40-year projected fluence value of approximately 29 EFPY. They were determined to not meet 10 CFR 54.3 Criterion (3), because they are not based upon time-limited assumptions defined by the current operating term, which is 40 years. Therefore, the reactor coolant system heatup and cooldown limits are not TLAA's as defined in 10 CFR 54.3(a).

The P-T curves are periodically updated based upon projected embrittlement data from the surveillance program that bounds the applicable operating period, as required by 10 CFR 50, Appendix G. The analyses are also updated whenever new information is available that would significantly affect the projections, either from the Reactor Vessel Surveillance Program or from other industry sources.

In spring 2001, surveillance Capsule X was removed from the Robinson Nuclear Plant reactor vessel. The surveillance test results for Capsule X were documented in WCAP-15805 and were submitted to the NRC in April 2002. This included fluence projections for 29 EFPY (40 years) and 50 EFPY (60 years). In March 2003, WCAP-15827, Rev. 0, was issued that generated a number of pressure-temperature limit curves for the Robinson Nuclear Plant based on the latest available reactor vessel information and fluence values from WCAP-15805, which were updated to reflect actual power realized from the Refueling Outage (RO)-21 power uprate. The new heatup and cooldown P-T limit curves were generated using a combination of methodologies, including the K_{Ic} methodology and the circumferential flaw methodology from ASME Code Case N-641, and the axial flaw methodology from the 1995 ASME Code, Section XI, through the 1996 Addenda. Heatup and cooldown P-T limit curves were developed for 30 EFPY, 35 EFPY, 40 EFPY, 45 EFPY, and 50 EFPY.

The 50 EFPY Appendix G curve shows that operating margin will exist during the period of extended operation with respect to consideration of neutron embrittlement of reactor vessel materials. Due to the beneficial effects resulting from the application of Code Case N-641, the 50 EFPY curves lay to the left of the current Technical Specifications P-T curves. Therefore, the current LTOP setpoint and enable temperatures are conservative for future curves. Specific P-T limit curves and appropriate LTOP setpoint limits will be submitted in accordance with 10 CFR 50, Appendix G, and current licensing basis requirements.

RAI 4.2.3-1 PARTS 1 AND 2

Part 1: 10 CFR 54.21(d) requires, in part, applicants to provide a summary description of TLAAs for the periods of extended operation for their facilities. FSAR supplement descriptions for TLAAs should summarize why the TLAAs have been performed, briefly what the TLAAs involve, and how the results of the TLAAs demonstrate that the TLAAs are acceptable for the period of extended operations, in accordance with 10 CFR 54.21(c)(1). Amend the FSAR supplement descriptions for PTS and USE, as given in Sections A.3.2.1.1 and A.3.2.1.2 of the LRA, to provide your technical basis why the TLAAs have been demonstrated to be in compliance with the requirements of 10 CFR 54.21(c)(1).

Part 2: 10 CFR 54.21(d) requires, in part, applicants to provide a summary description of TLAAs for the periods of extended operation for their facilities. Pursuant to 10 CFR 54.21(d), provide your FSAR supplement description for the RNP P-T and LTOP limits, as applicable to the period of extended operation.

RNP Response:

Part 1:

The RNP Response to RAI 4.2.1-1 describes how the TLAA for PTS has been demonstrated to be acceptable for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(ii).

The RNP Response to RAI 4.2.2-1, Part 1, describes how the TLAA for USE has been demonstrated to be acceptable for the period of extended operation pursuant to 10 CFR 54.21(c)(1)(ii).

Analyses for PTS and USE were identified as TLAA's and were described and evaluated in Section A.3.2.1 of the UFSAR Supplement, as required by 10 CFR 54.21(d). Section A.3.2.1 provides the technical basis for compliance with the requirements of 10 CFR 54.21(c)(1) with respect to these TLAAs.

Part 2:

The RNP Response to RAI 4.2.2.3-1 describes that PT and LTOP limits were determined not to be TLAA's because they did not meet the six applicability criteria 10 CFR 54.3(a). Therefore, they are not required to be described within the UFSAR supplement.

The P-T curves and LTOP limits are periodically updated as required by 10 CFR 50, Appendix G, based on fluence projections that bound the applicable operational period. The analyses are also updated whenever new information is available that would significantly affect the projections, either from the Reactor Vessel Surveillance Program or from other industry sources.

Surveillance Capsule X was removed from the RNP reactor pressure vessel in 2001. Based upon the evaluation of test results from this capsule, updated PT limit curves have been developed for various fluence values up to 50 EFPY. Refer to the RNP Response to RAI 4.2.2.3-1 for a discussion of these results. This response explains that adequate operating margin will be available to safely operate the plant during the period of extended operation.

RAI 4.3-1

Section 4.3.1 of the LRA contains a discussion of the transients used in the design of the reactor coolant system components at RNP. The LRA used design transients, postulated transients, and selected transients inter-changeably. Please clarify the differences and specifically designate the category of transients used in the design of the RCS components.

RNP Response:

During the design process for RCS components, for each type of thermal transient that would affect the component in service, the postulated number of occurrences within the 40-year design life of the component was used as the number of cycles in the fatigue analysis. These have been referenced as both "design transients" and "postulated transients," and these terms may be used interchangeably.

"Selected transients" are those that are monitored directly in the Fatigue Monitoring Program, since they have contributed to significant fatigue usage in one or more fatigue analyses. Refer to UFSAR Table 3.9.1-1 on page A-7 of the LR Application. Selected transients have been estimated for equipment design purposes and are not intended to be an accurate representation of actual transients or operating experience. Therefore, the selected transients represent design cycles that bound the actual cycles anticipated during the period of extended plant operation.

RAI 4.3-2

Section 4.3.1 of the LRA discusses the adjustments to "cumulative cycle counts." While partial cycle of design transients are defined and used in the ASME B&PV Code Section III (the Code), the discussion contained in the LRA is confusing. Please identify the Edition and Addendum of the Code used in your explicit fatigue analysis, clarify statements in the last paragraph of page 4.3-2 and provide the following information for each of the transients selected in the RNP Fatigue Monitoring Program (FMP):

1. The number of design cycles, current number of operating cycles, a description of the design transients, and for partial cycle transient, the method used to determine the fraction of a full cycle mathematically.

2 The number of full range operating cycles estimated for the past plant operation and a description of the method used to estimate the number of cycles for the remaining present life and during the extended life. Also please identify whether the assumed cycle data is developed on the basis of past operation and present plant operation mode (method).

3 The mechanism proposed to adjust and track transients included in the LRA for the remaining and extended life of the plant if operational procedures, which are used as the basis for future operation, are modified.

4 A quantitative comparison of the cycles and severity of the design transients listed in the LRA with the transients monitored by the FMP described in Section B.3.19 of the LRA. Identify any transients listed in the LRA that are not monitored by the FMP and explain why it is not necessary to monitor these transients.

RNP Response:

The RNP UFSAR, Section 3.2 and component specifications identify the applicable design codes for RNP components as shown in the following table.

Applicable Design Documents for RNP Components [1]

Component	Code of Construction	Edition/ Addenda
Reactor Vessel	ASME Section III, Class A	1965
Steam Generator: Tube Side Shell Side	 ASME Section III, Class A ASME Section III, Class C	 1965 / Summer 1966 1965 / Summer 1966
Pressurizer	ASME Section III, Class A	1965
Pressurizer Relief Tank	ASME Section III, Class C	1965
Pressurizer Safety Valves	ASME Section III	1965
Reactor Coolant Piping	USAS B31.1	1965
Reactor Coolant Pumps	ASME Section III, Class A	1965
CVCS	ASME Section III, Class C [2]	1965
Auxiliary Coolant System	ASME Section VIII [3]	1965
Sampling System	ASME Section III, Class C [4]	1965
Waste Disposal System	ASME Section III, Class C [5]	1965
SI System	ASME Section III, Class C [6]	1965
CSS	ASME Section III, Class C [7]	1965
Service Water Piping	USAS B31.1 and AWWA Class C 200 [8]	1965
Service Water Valves	USAS B16.5, 16.1, & 16.2	1965
AFW Piping	USAS B31.1	1965
AFW Valves	USAS B16.5	1965

Notes:
1. Data obtained from the RNP UFSAR, Section 3.2, and component specifications.
2. The shell sides of the non-regenerative, seal water, and excess letdown heat exchangers were designed to ASME Section VIII, and the piping and valves were designed to USAS B31.1.
3. The CCW loop, RHR, and SFPC loop piping and valves were designed to USAS B31.1. The tube sides of the RHR and SFPC heat exchangers, and the spent fuel pit filter and demineralizer, were designed to ASME Section III, Class C.
4. The shell side of the sample heat exchangers was designed to ASME Section VIII (Div. 1). The piping and valves were designed to USAS B31.1.
5. The piping and valves were designed to USAS B31.1.
6. The RWST was designed to American Water Works Association (AWWA) D100-65. The shell side of the RHR was designed to ASME Section VIII. The BIT was designed to ASME Section VIII, Division 2. The piping was designed to USAS B31.1, and the valves were designed to USAS B16.5.
7. The piping was designed to USAS B31.1, and the valves were designed to USAS B16.5.
8. Portions of the piping were designed to AWWA Class C.200.

1. The following table includes a description of the design transients, the number of cycles specified in the Westinghouse design specifications, the number of cycles specified as design limits in the UFSAR, the number of cycles specified as limits in the RNP Fatigue Monitoring Program, the number of cycles to-date (as of year 2000), and the projected number of cycles for 60 years.

TRANSIENT DESCRIPTION	ANALYZED CYCLES (CYCLE LIMITS)				ACTUAL CYCLES		60-Year Projection
	Westinghouse Design Specifications	UFSAR (Basis)	Fatigue Monitoring Procedure	SDAFW/FW Connections [5]	2001 Final Summary	2000 Interim Summary	(Based Upon 2000 Summary)
Normal Condition Transients:							
Plant Heatup	200	200 (5/year)	200	149	87 [1]	87	120
Plant Cooldown	200	200 (5/year)	200	149	87 [1]	86	120
Unit Load, 15%/minute	29,000	(2/day) 29,000	19,000 [2]	363	208 [1]	273	607
Unit Unload, 15%/minute	29,000	(2/day) 29,000	19,000 [2]	361	203 [1]	265	588
Step Increase, 20% of Full Power	2,000	(1/week) 2,000	2,000	1,333	0	43	136
Step Decrease, 20% of Full Power	2,000	(1/week) 2,000	2,000	1,333	0	43	136
Large Step Decrease, 95% of Full Power	80	80 (2/year)	80	53	0	---	---
Steady State Fluctuations	Infinite	Infinite	Infinite		N/C	---	---
Feedwater Cycling	25,000	N/S	N/C		N/C	N/C	---
50% Step Load Decrease	200	N/S	N/C		N/C	N/C	---
Test Condition Transients:							
Primary Hydro Test	1 [3]	1	1		1	1	1
Secondary Hydro Test	1	N/S	N/C		N/C	N/C	---
Primary Leak Test, 2,500 psi	5 [4]	40	40		[6]	2	---
Secondary Leak Test	50	N/S	N/C		N/C	N/C	---
Primary to Secondary Leak Test Secondary to Primary Leak Test	5 5	N/S N/S	N/C N/C		N/C	N/C	---
SDAFW Pump Tests [7]				33	20	---	40 [8]
Upset Condition Transients:							
Loss of Load	80	N/S	80	7	3	---	6 [8]

Loss of Power (AC)	40	N/S	N/C	27	N/C	N/C	---
Partial Loss of Flow	80	N/S	80	7	1	---	2 (8)
Reactor Trip from > 5% Power	400	400 (10/year)	400	215	193	193	226
Loss of Secondary Pressure	6	N/S	N/C		N/C	N/C	---

NOTES:
N/S = not specified, N/C = not counted
(1) Counts do not include partial cycles.
(2) To be adjusted to 19,000 for EAF on pressurizer spray nozzle prior to period of extended operation.
(3) Limiting value for steam generator reported. Other specifications identified 5 cycles for this event.
(4) Limiting value for reactor vessel reported. Other specifications identified 50 cycles for this event.
(5) The SDAFW/FW fatigue analysis transients are interim limits that will remain in effect until either the connections are reanalyzed (potentially due to operational changes reducing the number of injections per surveillance test) or until the connections are replaced.
(6) Leak tests are performed during heatup at normal operating pressure, are bounded by heatups, and are not counted separately.
(7) Limit is for 33 surveillance tests, and assumes each surveillance test includes three injections per connection. Limit is to be added to fatigue monitoring procedure prior to next summary review.
(8) Projections based upon 2001 summary (30 years), using overall average rate.

During the detailed review of the RNP Fatigue Monitoring Program, it was determined that partial cycles of heatup and cooldown had been tabulated separately from the full range heatups and cooldowns, but these were not counted in the total number of reported heatups and cooldowns. Therefore, it was necessary to disposition these partial cycles by converting them to the number of equivalent full temperature range cycles, which is a much lower number. This is because, as ΔT is reduced from that assumed in the fatigue analysis, the thermal stress is reduced proportionally, and as the stress is reduced, the fatigue usage is reduced exponentially, based upon the fatigue curve.

For example, the cumulative number of heatup cycles reported in the Fatigue Monitoring Program summary was 87, with an additional 273 partial heatups reported. The heatup transient used in the fatigue analysis was defined as a temperature change from 100°F to 547°F (which is a full temperature range cycle of 447°F ΔT). However, 208 of the reported cycles were determined to have been temperature changes that had occurred during plant loading events, where the temperature only changes from 547°F up to 575°F (a maximum ΔT of 28°F). An additional 65 of the partial heatup cycles were from subcritical conditions where the ΔT was 65°F or less. Only 87 cycles were full temperature range heatups (447°F ΔT). The cumulative totals were corrected by calculating the number of equivalent full temperature cycles associated with the ΔT's of the actual cycles that had been recorded. The number of equivalent full temperature range cycles, N, was computed using the methodology provided for this purpose in USAS B31.1, 1967 Edition, Section 102.3.2:

$$N = N_E + r_1 5\, N_1 + r_2^5\, N_2 + r_3^5\, N_3 + \ldots\ldots + r_n^5\, N_n$$

where N_E is the number of cycles at full temperature change ΔT_E for which the thermal stress has been calculated; N_1, N_2, N_3, …., and N_n are the numbers of cycles at lesser temperature changes ΔT_1, ΔT_2, ΔT_3, ….., and ΔT_n, and r_1, r_2, r_3, …., and r_n are the temperature change ratios for other cyclic thermal load sets. $r_1 = \Delta T_1 / \Delta T_E$ $\qquad$ $r_2 = \Delta T_2 / \Delta T_E$

For the heatup example, $N = 87 + (28/447)^5\,(208) + (65/447)^5\,(65)$

$$N = 87 + .0002 + .00423$$
$$N = 87.00443$$
$$\underline{N = 87}$$

Similarly, there were 86 full temperature cooldowns reported, and an additional 265 partial cooldown cycles reported. This included 261 cycles with a of ΔT of <65°F, and 4 cycles with a ΔT of <225°F.

For the cooldown example, $N = 86 + (65/447)^5 (261) + (225/447)^5 (4)$

$$N = 86 + 0.017 + 0.129$$
$$N = 86.146$$
$$\underline{N = 86}$$

Therefore, the cumulative number of heatups was retained as 87, but the 273 partial heatup cycles were dismissed. The number of cooldowns was retained as 86, but the 290 partial cooldown cycles were dismissed on this basis. Similar adjustments were made for the step increase and step decrease transients.

2. For transients except plant heatups, cooldowns, and reactor trips from power, the projections are conservatively extrapolated to sixty years based on the average number of transients per year that have been experienced during the plant life to-date (through April 2000).

   For heatup, cooldown, and trip transients, an extrapolation method was used to account for "learning curve effects" and system shakedowns which occurred early in plant life. For these transients, the rate of accumulation was very high during the first 20 years of plant life (3.8 per year for plant heatups and cooldowns, and 9.1 per year for reactor trips from power), and have diminished dramatically, such that in the last ten years they each average only 1.1 transients per year. (182 trips were recorded through the end of 1990, and 193 were recorded through April 2000, resulting in 11 occurrences in 10 years, or approximately 1.1 per year. 76 heatups and 76 cooldowns were recorded through the end of 1990, and 87 heatups and 86 cooldowns were recorded through April 2000, resulting in 11 occurrences in 10 years, or approximately 1.1 per year). This reduced rate of accumulation is believed to represent the best estimate of future operation. Therefore, the projections for heatups, cooldowns, and reactor trips is based upon the average number of these transients experienced during the 1991-2000 time period. Considerable margin exists between the 60-year projected values and the original 40-year design limits. More conservative projection methods could have also been used with acceptable results.

3. If operating procedures are changed to the extent that the fatigue usage associated with a particular operation is increased beyond that assumed in the most recent fatigue analysis for the component, the affected fatigue analyses would be revised to account for the more severe thermal stress. The acceptance limit would remain that the CUF must be less than 1.0. If the number of design cycles remains unchanged (i.e., the increase in fatigue usage from the previous analysis does not result in CUF > 1.0), then no change would be required to the Fatigue Monitoring Program limits. If the number of cycles had to be reduced to obtain a CUF value less than 1.0, this

reduced number of cycles would become the new Fatigue Monitoring Program cycle limit.

An example of this process is related to the environmental fatigue calculations performed for license renewal. Environmental fatigue calculations were performed for the pressurizer components, and in order to qualify the pressurizer spray nozzle safe end (EAF-adjusted CUF < 1.0), the number of load/unload transients was reduced from 29,000 to 19,000. For the period of extended operation, this will result in a change in the Fatigue Monitoring Program cycle limit to 19,000 for the load and unload transient cycles.

4. Each of the transients specified in the table above has a different impact on the fatigue evaluation for any particular component, and those that are not counted are denoted by "N/C." Those that are counted are the ones most likely to result in fatigue cracking of one or more components. As the cycle counts for these transients approach their design limits, they serve as leading indicators of fatigue. Those that are less likely to result in fatigue, due to a much lower contribution to fatigue usage, would not be useful leading indicators, and need not be counted. The influence of any particular transient on the CUF for a given component is a determining factor in whether or not that particular event should be counted and tracked. In addition, the total CUF for a given component may also influence whether or not that particular event should be counted and tracked (i.e., if the CUF is very low, none of the contributing events are important to track).

   Based on the above, a review was performed to identify the design cycles from those in the table that have a significant impact on the component fatigue analyses for RNP. First, component locations with individual CUF values of 0.1 or more were identified. This screening value of 0.1 allows for margin (i.e., a factor of 10) with respect to the allowable limit. Then, the individual transients that contribute to 50% or more of the fatigue usage for these locations with a CUF value of 0.1 or more were identified. These are required to be tracked. The loss of load transient and partial loss of flow transient had not been included in the Fatigue Monitoring Program prior to the evaluation, but were added to the program because they meet the criteria specified above. Records were reviewed to determine past occurrences, and the counts were updated as required. These are not approaching their design limits.

RAI 4.3-3

Sections 4.3.1.1 and 4.3.1.2 of the LRA states that the number of transients projected to occur during a 60-year operational period is significantly less than the number or transients originally postulated for 40 years of operation and used in the fatigue analyses. Please provide data or references, specific for the pressurizer and the surge line, to justify the above statement.

The number of cycles and the magnitude of temperature difference (Delta-T) of the pressurizer and the surge line transients depend on the heatup and cooldown method. Several plants modified the method for plant heatup and cooldown to mitigate the pressurizer insurge/outsurge transients in the late 1990s. Please justify the projected RNP transient cycles in view of the past and future heatup and cooldown methods. In addition, please discuss how the TLAA for the pressurizer and the surge line will be re-evaluated, if the operating modes during the extended plant operation are different from those assumed in your design assumptions.

RNP Response:

The RNP Response to RAI 4.3-2, Part 2, provides a description of the method used to make 60-year transient projections, and the bases and rationale for the conclusions provided in the RNP LRA.

The RNP Response to RAI 4.3-4 provides a description of the insurge/outsurge transient analysis performed to evaluate transients that exceed pressurizer heatup and cooldown limits. This analysis is included in WCAP-14209, which was submitted to the NRC via CP&L letter, Serial RNP/94-1867: "Submittal of WCAP-14209, 'Evaluation of the Effects of Insurge/Outsurge Transients on the Integrity of the Pressurizer at H. B. Robinson Unit 2'," dated October 28, 1994. Previous transient cycles that exceeded the specified pressurizer heatup and cooldown limits were evaluated, along with several extra cycles to allow for any unanticipated future transients above these limits. RNP has modified the methods for plant heatup and cooldown to mitigate the pressurizer insurge/outsurge transients, and to assure that the existing heatup rate limit of 100°F/hr and cooldown rate limit of 200°F/hr are maintained as required by the Technical Specifications. The method for performing plant heatup and cooldown during the extended operating period will continue to conform to the specified pressurizer heatup and cooldown limits.

If a change in operational method were contemplated that might result in exceeding the specified heatup or cooldown rates, the fatigue analyses for the pressurizer and surge line would be evaluated, and, if necessary, revised to account for the increased fatigue usage. However, no such change is anticipated.

RAI 4.3-4

Section 4.3.1.2 of the LRA states that if a significant ΔT exists between the pressurizer and the water entering the pressurizer via the surge line, the cooldown limits for the pressurizer may be exceeded. For the February 1994 transient that exceeded the plant cooldown limit, RNP performed a detailed evaluation, presented in WCAP-14209, including a number of previous out-of-limit pressurizer transients. It was concluded that the 40-year CUF is below 1.0 which is acceptable. However, there was no mention in regard to how any other design requirements of the pressurizer associated with the ΔT limit would be addressed. Please provide these information and the RNP specific ΔT limit during heatup and cooldown.

RNP Response:

The Technical Specifications for RNP require that pressurizer heatups not exceed a rate of 100°F/hr and cooldowns not exceed a rate of 200°F/hr. If a transient exceeds these limits, actions must be taken to evaluate and determine the effects of the out-of-limit condition on the structural integrity of the component. WCAP-14209 was prepared to complete the detailed evaluation of the February 1994 transient. During review of this transient, it was discovered that additional transients exceeding these rates had previously occurred, and each of these were fully evaluated in the report. The detailed evaluation included identification of a number of past out-of-limit pressurizer transients, development of enveloping transients, determination of stresses in critical locations in the pressurizer lower head, and evaluation of these stresses on the structural integrity of the pressurizer.

Pressurizer structural integrity was evaluated with respect to non-ductile fracture and fatigue requirements. The results of the evaluation showed that the out-of-limit transients did not compromise the structural integrity of the Robinson Nuclear Plant pressurizer. Fracture analysis showed stress intensity factors calculated for a range of assumed flaw depths, with an ASME Code-recommended aspect ratio of 6:1, to remain below the material fracture toughness for the applied transient conditions. The ASME Code fatigue analysis showed that the increase in fatigue usage from these transient events was small.

The pressurizer surge line was also affected by these transients, but is not subject to the 100°F/hr heatup limit or the 200°F/hr cooldown limit contained within the Technical Specifications. However, insurge/outsurge transients of this type were previously addressed in detail for RNP in the plant-specific applicability study performed in response to NRC Bulletin 88-11.

The enveloping transients were defined so as to include additional cycles of these types of transients in the fatigue evaluation, so that the results of the report could be used to determine the acceptability of future out-of-limit transients, if they were to occur. However, after the problem was identified, operational strategies were developed and implemented to mitigate or eliminate significant pressurizer insurge/outsurge transients, and plant heatup and cooldown procedures were modified to prevent temperature changes at rates above the applicable limits.

The original Pressurizer Stress Report for RNP included a determination of cyclic analysis requirements in accordance with the 1965 Edition of the ASME Code, Section III, Paragraph 415.1. The only components within the pressurizer that required an explicit fatigue analysis were the surge and spray nozzles. The only transients that required evaluation for these nozzles were the loading and unloading transients, since the design requirements for other transients had been satisfied. The fatigue analysis resulted in a CUF value of 0.264 for the carbon steel surge nozzle and in a CUF value of 0.161 for the stainless steel surge nozzle safe end. The fatigue analysis of the carbon steel spray nozzle resulted in an infinite number of allowable cycles and in a CUF value of 0.096 for the stainless steel spray nozzle safe end. This analysis showed that the surge nozzle was the limiting location among the carbon steel components in the pressurizer, and that the code design requirements were met.

WCAP-12962 includes a fatigue analysis of the pressurizer performed by Westinghouse in September 1991 to account for thermal stratification transients in the pressurizer surge line. The limiting location at the RCS hot leg nozzle was determined to have a CUF value of 0.98.

In February 1994, a pressurizer transient occurred at RNP that exceeded the plant Technical Specifications limits. WCAP-14209 was prepared in 1994 to complete the detailed evaluation of the transient. The analysis defined a number of other past out-of-limit transients, including 16 cooldown and 8 heatup excursions, and developed two new enveloping transient models that were used to bound the fatigue usage associated with these events. The analysis conservatively calculated the fatigue usage that would result from 40 occurrences of each of the two new transients.

The pressurizer surge line was instrumented for one operating cycle to validate the assumptions used in WCAP-12962, and to provide detailed transient data for a more accurate analysis. This data determined the moment ranges were larger than previously analyzed. Spring hangers were modified to accommodate the thermal stratification movements, reducing the amplitude of the cyclic stress loadings. Measured data was used in a structural reanalysis and revised fatigue analysis that was documented by WCAP-12962, Supplement 1. The limiting location at the RCS hot leg nozzle was determined to have a CUF value of 0.96.

RAI 4.3-5

Section 4.3.1.3 of the LRA referenced WCAP-10322, Rev.1, of October 1984, for explicit fatigue analyses of reactor internals holddown spring and alignment pins. WCAP-10322, Rev.1, is the stress report of 312 standard reactor core structures. Please provide justification of the direct applicability of this stress report to the RNP reactor internals holddown spring and alignment pins.

RNP Response:

WCAP-10322 is not directly applicable to RNP. RNP performed an engineering evaluation of materials used for replacement control rod guide tube support pins. This evaluation included references to two Westinghouse WNEP documents. These documents in turn referenced WCAP-10322, Rev. 1, which includes explicit fatigue analyses for the holddown springs and alignment pins. Direct reference to the fatigue evaluation in WCAP-10322 was not part of the engineering evaluation, and RNP was not required to establish a TLAA for the reactor vessel internals. However, RNP conservatively incorporated the indirect reference to the fatigue evaluation for these components as being within the scope of license renewal.

RAI 4.3-6

The insurge/outsurge thermal transients noted in Section 4.3.1.2 of the LRA are described as loading transients for the pressurizer. Typically, there are a number of components within the pressurizer, other than the surge nozzle, where the CUF may approach 1.0 for a 40-year operation. Please provide a list of components of the RNP pressurizer with high 40-year CUF values, for which the ASME Section III limit of CUF=1.0 will be met including the period of extended operation, or describe the aging management programs that will be used to manage fatigue of these components for the period of extended operation. Also provide your assessment of the environmental effects on the fatigue analyses for these pressurizer components and the surge line.

RNP Response:

None of the pressurizer components which have an ASME Code, Section III, Class A, fatigue analysis has a 40-year or 60-year CUF value that exceeds 1.0 without consideration of environmental effects. Analyzed components include the pressurizer lower head, heater well, spray nozzle, spray nozzle safe end, surge nozzle, surge nozzle safe end, and instrument nozzles.

When environmental fatigue effects were considered, the only component in the pressurizer that was determined to have an EAF-adjusted fatigue value that exceeds 1.0 is the pressurizer surge nozzle safe end (stainless steel), which is welded to the pressurizer surge line. Fatigue of this component will be managed in the same manner as the adjacent stainless steel pressurizer surge line components, including the surge line piping and RCS hot leg nozzle. Refer to the RNP Response to RAI 4.3-10 for additional information concerning management of fatigue for the surge line and adjacent components with EAF-adjusted CUF values over 1.0.

RAI 4.3-7

Section 4.3.1.4 of the LRA presented the fatigue design analyses associated with the AFW to FW branch connections. The analyses demonstrated the calculated CUF value of less than 1.0 for the period of extended operation of the replacement connections, using ASME Code Section III, Subsection NB requirements. These connections are considered as non-standard (ASME) components for which the stress indices or stress intensification factors may not be defined. Provide the calculated CUF of the six replacement branch connections and confirm that no other nonstandard components were used in safety systems at RNP, or provide a justification of their acceptability for use at RNP. Also describe the aging management program(s) that will be used to provide assurance that the CUFs for these connections will not exceed the limit of 1.0 for the period of extended operation.

RNP Response:

The RNP system design has three 4 inch-to-16 inch AFW-to-FW connections downstream of the motor-driven AFW pumps, and three 4 inch-to-16 inch AFW-to-FW connections downstream of the steam-driven AFW pump. Only the three connections downstream of the motor-driven AFW pumps were replaced with the thermal sleeve design in the early 1970's. These three connections were designed to ANSI B31.1 requirements and no TLAA was identified for them.

The three 4 inch-to-16 inch AFW-to-FW connections downstream of the steam-driven AFW pump were not replaced due to the relatively low usage of the steam driven pump. These three original connections were also designed in accordance with ANSI B31.1 design requirements. However, an ASME Code, Section III, Class 1 fatigue analysis was prepared for these connections in the mid-1990's, which was determined to be a TLAA for license renewal.

During the license renewal review of this fatigue analysis, an error was discovered, and the analysis was revised, with a resulting CUF value of 0.99 based upon a reduced number of postulated design transients and a postulated number of SDAFW pump surveillance tests. These postulated numbers of transients are being incorporated as limits in the Fatigue Monitoring Program, as shown in the RNP Response to RAI 4.3-2.

At the current rates of occurrence, the limits would be reached at approximately year 50 during the period of extended operation. Since the reduced numbers of transients do not exceed the 60-year projections for these transients, additional actions may be required for these components for the period of extended operation. Prior to exceeding the reduced transient limits, the components will either be reanalyzed or replaced. The Fatigue Monitoring Program will be updated to reflect changes in the design basis, when appropriate.

Reviews performed during the RNP Integrated Plant Assessment found no nonstandard components used in safety systems. This includes each type of AFW/FW connection, which are not considered to be non-standard since the designs meet the ANSI B31.1 design requirements.

RAI 4.3-8

Section 4.3.2 of the LRA contains a discussion of the components with implicit fatigue design/analysis. The implicit fatigue design/analysis method is applicable to piping designed to the USAS B31.1 Code and auxiliary heat exchangers to the ASME Section III, Class C or ASME Section VIII requirements.

For piping, the LRA indicates that the USAS B31.1design methods apply reduction factors to allowable stresses for specified numbers of cyclic loadings. For 60 years of operation, the number of thermal cycles imposed upon B31.1 piping systems is not expected to exceed the original design assumptions. Please justify this expectation and the assumption that USAS B31.1 limit of 7000 equivalent full range cycles will not be exceeded during the period of extended operation for the B31.1 piping systems.

The LRA indicates that auxiliary heat exchangers at RNP were designed in accordance with Westinghouse specification and ASME Section III, Class C, or ASME Section VIII Codes. It further states that the design rules for ASME Section III, Class C are essentially identical to the B31.1 rules using stress range reduction factors. There is no mention on the fatigue design method if heat exchangers were designed to ASME Section VIII Code requirements. Provide the fatigue design method for this case.

RNP Response:

The same transients that contribute to fatigue usage in components designed to ASME Section III, Class A rules lead to fatigue usage in piping systems and other components designed to implicit fatigue design rules of USAS B31.1 and ASME Section III, Class C rules. For example, the RCS piping is designed to USAS B31.1 rules and these lines are exposed to the same transient cycles as the Class A components. Certain exceptions exist where transients have been identified that are not typical of the Class A components, such as thermal stratification in the pressurizer surge line. However, in these cases, the original implicit fatigue analyses have been superseded by explicit fatigue analyses to account for these specific transients. Another exception is for piping systems operated on a periodic basis, such as primary sampling system, which has been evaluated separately. In this case, the specific piping is no longer used for this purpose.

The 60-year transient projection results apply to both the explicit Class A fatigue analyses and the implicit Class C and USAS B31.1 analyses. Fatigue Monitoring Program transient data was evaluated to show that the number of transients expected in 60 years is less that the number originally postulated for 40 years in the original design. These results are also applicable for the implicit analyses, since the same thermal transients affect the components. These systems will not be exposed to more cycles than they were originally designed to accommodate. Therefore, if a component was not expected to exceed 7,000 cycles during the original design, it is not expected to exceed 7,000 cycles during the period of extended operation. The LRA did not state that no component will be exposed to more than 7,000 cycles, but instead stated that they will not be exposed to more cycles than the number they were originally designed to experience.

The reduced rate of accumulation of transient cycles in the most recent 10 to 15 years of plant operation is due to operational improvements, such as the scram frequency reduction program, resulting in fewer plant shutdowns and restarts, and longer run cycles, which translates into fewer transient cycles. In addition, the original design requirements were specified assuming the plant would be operated using daily load following: Robinson Nuclear Plant is used as a base-load facility with far fewer actual transients associated with power level changes than assumed in the design. Therefore, the 60-year projections have sufficient remaining margin to permit continued operation during the license renewal period without requiring reanalysis of plant components for additional operational cycles.

The tube sides of the following auxiliary heat exchangers were designed in accordance with the ASME Code, Section III, Class C requirements, and the shell sides were designed in accordance with the ASME Code, Section VIII, Division 1, requirements:

Regenerative Heat Exchanger
Non-Regenerative Heat Exchanger
RHR Heat Exchanger
Seal Water Return Heat Exchanger
Excess Letdown Heat Exchanger
SFPC Heat Exchanger
Sample Heat Exchanger

The CCW heat exchanger shell and tube sides were designed to ASME Code, Section VIII, requirements.

In designing a vessel to ASME Section VIII, Division 1 requirements, the wall thickness is computed based upon consideration of primary stresses. However, cyclic loadings are considered to be secondary stresses. Therefore, there is no requirement to reduce the allowable stress based upon specific numbers of cyclic loadings, as in USAS B31.1 Code. Section VIII requirements state that the loads shall not induce a combined maximum primary membrane stress plus primary bending stress across the thickness which exceeds 1.5 times the maximum allowable stress. It is recognized that high localized discontinuity stresses may exist in vessels designed and fabricated in accordance with these rules. Insofar as practical, design rules have been written to limit such stresses to a safe level consistent with experience.

RAI 4.3-9

Section 4.3.3 of the LRA discusses RNP's evaluation of the impact of the reactor water environment on the fatigue life of components during the period of extended operation. The discussion references the fatigue sensitive component locations for an older vintage Westinghouse plants identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." Four (4) of these locations have ASME Section III specific fatigue analyses, and three (3) have USAS B31.1 implicit fatigue analyses.

The LRA indicates that the later Environmentally Assisted Fatigue (EAF) relationship developed in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," were used in the calculation of environmental fatigue multiplier (F_{en}). Provide the results of the F_{en} and EAF-adjusted CUF calculation for each of the seven (7) component locations listed in NUREG/CR-6260.

RNP Response:
The requested information is provided by the following table:

LOCATION	Original CUF	F_{en} Multiplier	EAF-Adjusted CUF
1. RPV Shell at Core Support Pads	0.229	2.23	0.512
2. RPV Outlet Nozzle	0.586 [1]	1.70	0.997
3. RPV Inlet Nozzle	0.370	2.41	0.893
4. Pressurizer Surge Line	0.96 [2]	15.35 [3]	14.7
5. Charging Nozzle	0.031	15.35 [3]	0.468
6. SI Nozzle	0.046	15.35 [3]	0.699
7. RHR Tee	0.022	15.35 [3]	0.334

<u>NOTE 1:</u> The original CUF value for the RPV outlet nozzle was 0.628, but was reduced to 0.586 in a revised analysis based upon a reduction in postulated load/unload cycles from 29,000 to 26,500. Another revised fatigue analysis for the pressurizer spray nozzle safe end resulted in a further reduction of the postulated load/unload cycles to 19,000. The Fatigue Monitoring Program will be revised to limit the number of permissible load/unload cycles to reflect the lowest number of analyzed cycle. The analysis for the RPV outlet nozzle remains conservative.

NOTE 2: The pressurizer surge line analysis includes the RCS hot leg nozzle, which is the limiting location within the analysis. This updated analysis was prepared in response to NRC Bulletin 88-11, and takes into account loadings from thermal stratification (based upon measured data).
NOTE 3: Environmental effects were uniformly applied for stainless steel locations without consideration of threshold criteria that might indicate an absence of environmental conditions, resulting in a maximized F_{en} multiplier. Therefore, the environmental adjustments to the CUF results are considered to be conservative.

RAI 4.3-10

Section 4.3.3 of the LRA states that an EAF-adjusted fatigue calculations were performed for seven RNP pressurizer locations in addition to locations specified in NUREG/CR-6260. It appears that the limiting locations are the surge nozzles at the pressurizer and the hot leg. Clarify whether the hot leg nozzle is included in the EAF-adjusted fatigue calculations.

Potentially the EAF-adjusted CUF may be greater than 1.0 and the performance of periodic volumetric examinations at least once during every 10-year interval may be required. Please clarify how you intend to address the potential exceedence of the CUF at the pressurizer and the hot leg nozzle. In addition, the inspection program can not be considered adequate unless the applicant can demonstrate that the examinations, at the prescribed interval, will prevent any crack from becoming unstable before the next inspection. Please discuss how this demonstration is satisfied under AMP B.3.19.

RNP Response:

The RCS hot leg nozzle (branch connection where pressurizer surge line attaches to the RCS hot leg piping) was included in the pressurizer surge line fatigue analysis performed in response to NRC Bulletin 88-11, and was the bounding location. The components in the pressurizer surge line analysis are stainless steel.

The pressurizer surge line (including the RCS hot leg nozzle) was also one of the seven locations identified in NUREG/CR-6260 that was evaluated at RNP for environmental fatigue effects. The EAF-adjusted CUF value for the pressurizer surge line, including the hot leg nozzle, exceeds 1.0 based upon current methodology.

The pressurizer surge nozzle is located at the bottom of the pressurizer and is an integral part of the carbon steel lower head casting (i.e., no weld between the lower head and the nozzle). A carbon steel reducer is welded to the surge nozzle and a stainless steel safe end is welded to the reducer. The stainless steel safe end is welded to the stainless steel pressurizer surge line.

When the environmental fatigue calculations were performed, the carbon steel pressurizer surge nozzle and reducer were determined to have 60-year EAF-adjusted CUF values less than 1.0. However, the stainless steel safe end had an EAF-adjusted CUF value of over 1.0. Therefore, the pressurizer surge nozzle safe end, the pressurizer surge line piping, and the RCS hot leg nozzle, which are welded to each other, were the only components with an EAF-adjusted CUF value over 1.0. (Note: Each of these locations has a CUF value of less than 1.0

without consideration of environmental effects, which is the current licensing basis.)

Prior to the period of extended operation, either the EAF-adjusted CUF values for the pressurizer surge line and pressurizer surge nozzle safe end will be reanalyzed with resulting CUF values less than 1.0, or fatigue will be managed for these components through the use of periodic volumetric examinations performed in accordance with the ASME Code, Section XI, ISI Program requirements.

The current ISI Program already includes each of the critical welds for the surge line, including the RCS hot leg pipe-to-hot leg nozzle weld and the hot leg nozzle-to-surge line weld, which directly examines the limiting component in the plant (the hot leg nozzle). On the other end of the surge line, the three welds near the pressurizer surge nozzle are examined, including the nozzle-to-reducer weld, reducer-to-safe end weld, and safe end-to-surge line weld. Each of these locations has been examined during the current operating period, and no unacceptable indications were present upon completion of these examinations. Further examinations are required at least once during esch10-year ISI interval thereafter. The frequency of inspections is specified by Section XI requirements.

If volumetric examinations are used to manage fatigue of the surge line components, suitable analyses will be prepared prior to the period of extended operation to demonstrate that a postulated fatigue crack will not grow sufficiently during the inspection interval to exceed the critical flaw size associated with unstable growth.

As a result of the above response, the final paragraph in LRA Subsection A.3.2.2.2, "Environmentally Assisted Fatigue," is revised to read:

> "Therefore, an aging management program will be used to manage the effects of fatigue of the pressurizer surge line components in accordance with 10 CFR 54.21(c)(1)(iii) unless further analysis successfully justifies an environmentally-adjusted CUF of less than 1.0. Specifically, this will involve the following activities: (1) Prior to the period of extended operation, either the environmentally-adjusted CUF values for the pressurizer surge line and pressurizer surge nozzle safe end will be reanalyzed with resulting CUF values less than 1.0, or (2) Fatigue will be managed for these components through the use of periodic volumetric examinations performed in accordance with ASME, Section XI, ISI Program requirements; and (3) If volumetric examinations are used to manage fatigue of the surge line components, suitable analyses will be prepared prior to the period of extended operation to demonstrate that a postulated fatigue crack will not grow sufficiently during the inspection interval to exceed the critical flaw size associated with unstable growth."

RAI 4.3-11

In reference to Section 4.3.5, identify the design code and a description of the methodology on which the fatigue analysis of the hot piping penetrations is based, and support your conclusion that the specified bellows can withstand 4000 cycles without fatigue cracking.

RNP Response:

Section 3.8.1.1.6 of the UFSAR describes the containment penetrations at RNP. The applicable codes and standards are described in Section 3.8.1.2. In particular:

> *"Penetrations conform to the applicable sections of USAS N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors."*

LRA Section 4.3.5 does not refer to a fatigue evaluation of hot piping penetrations themselves. The evaluation performed is limited to the bellows for the penetration. According to the design specification for the bellows, they are designed in accordance with the ASME Code, Section III, Subsection NC, and bellows performance equations as listed in Section C of the Standards of the Expansion Joint Manufacturers Association (EJMA), Fifth Edition, 1980, including 1985 addenda. The fatigue evaluation was performed to qualify the bellows for 4000 cycles.

RAI 4.3-12

In reference to Section 4.3.5, please identify if the containment penetration bellows are included within the scope of the RNP Fatigue Monitoring Program. If not, please provide justification for not including these components in the program.

RNP Response:

The transients that contribute to fatigue of the containment penetration bellows are those that involve a full range temperature change in the piping system. At RNP, these are the plant heatup and plant cooldown transients that are monitored and controlled by the RNP Fatigue Monitoring Program. The UFSAR limits these to 200 heatup and cooldown cycles, based upon the 40-year design basis of the plant. The Fatigue Monitoring Program is used to assure these limits are not exceeded.

For license renewal, the number of heatup and cooldown cycles to-date were analyzed, 60-year projections were made, and the present limit of 200 heatup and cooldown cycles were shown to be conservative for 60 years of operation. Therefore, these limits will be retained. Since heatup and cooldown cycles are limited to 200 for 60 years, the bellows that are analyzed for 4,000 cycles will not exceed their design limits during the period of extended operation.

RAI 4.3-13

Section 4.3.6 of the LRA states that the basic allowable stress calculation of the Spent Fuel Cask Crane included dead weight, live load and impact allowance. Discuss the specific requirement on which the impact allowance was based, and indicate its magnitude.

RNP Response:

The spent fuel cask handling crane underwent a load rating capacity upgrade during the 1974/75 time frame. The structural upgrade was performed in accordance with CMAA-70.

The CMAA-70 specific requirement for impact allowance of the rated capacity is taken as 1/2% of the load per foot per minute of hoisting speed, but not less than 15%, nor more than 50%, of rated load.

The spent fuel cask handling crane support structure modifications utilized an impact allowable of 15% of the lift load.

RAI 4.3-14

Section 4.3.6 of the LRA states that the spent fuel crane is designed for 20,000 to 100,000 load cycles. Provide the basis for the upper and lower limits.

RNP Response:

The load cycle design requirement for the RNP spent fuel crane was based on less than 2500 load cycles over a 40-year period. This equates to a design requirement of less than 3750 load cycles for the 60-year license renewal period. The CMAA-70 crane classification for the RNP spent fuel crane is Class A1. Due to its low usage, the spent fuel crane was designed for the lowest range of cycles (20,000 to 100,000).

Class A1 cranes, which are standby Class A cranes, are used for standby service, with infrequent maintenance and long idle periods, i.e., "low usage." Additionally, crane specification CMAA-70 considers a crane with 20,000 load cycles as a "low usage" application. The CMAA-70 code provides an allowable stress range for structural design dependant on its usage (i.e., number of loading cycles).

A review of the operational history for the RNP spent fuel crane indicates that the original design requirement was conservative and will not be exceeded for the 40-year period. Therefore, by extrapolation, the requirement for the 60-year period will not be exceeded.

RAI 4.3-15

The minimum factor of safety for the spent fuel crane, as discussed in Section 4.3.6 of the LRA, is based on a maximum tensile strength of 58,000 psi for ASTM-A36 material. Verify that no members of the crane have a lower tensile strength. Also identify the members with the minimum factors of safety.

RNP Response:

The structural load-bearing members for the RNP spent fuel crane have been fabricated in accordance with CMAA-70 from ASTM A-36 steel (tensile strength of 58,000 psi).

A minimum factor of safety was provided for structural load bearing members based on a maximum allowable stress. The maximum basic allowable stress for any member under tension or compression is 17,600 psi. The 17,600 psi allowable is the "not to be exceeded allowable stress" as stated in the CMAA-70 crane specification for members subjected to repeated loading. The factor of safety reported in the LRA was given based on the tensile strength for ASTM A-36.

RAI 4.4-1

In the LRA Section 4.4, the applicant stated that thermal, radiation, and wear cycle aging analyses of electrical and I&C components required to meet 10 CFR 50.49 identified as time-limited aging analyses for RNP. Moisture is an environmental stressor. It is not clear to the staff if the aging effect due to moisture is addressed in the LRA.

RNP Response:

The EQ rule (10 CFR 50.49) identifies the six environmental conditions that must be included to establish qualification as: (1) temperature, (2) pressure, (3) humidity, (4) radiation, (5) chemicals, and (6) submergence. "Moisture" would be covered by humidity and submergence. Equipment that must be evaluated for these two conditions can be separated into either EQ cables or non-cable EQ equipment.

The NRC EQ Task Action Plan (TAP) (NUREG/CR-6384) does not identify moisture as a significant aging mechanism. During normal operations, equipment is only subjected to ambient humidity levels (20-90%), which the NRC EQ TAP dismisses as an aging stressor. EQ equipment is typically sealed, cable insulation is not effected by humidity, and exposure to leaks is investigated on a case-by-case basis.

EQ equipment that could be subjected to the environmental conditions of a loss-of-coolant accident (LOCA) is qualified by testing that includes a deluge spray of either borated or distilled water. EQ equipment that could be subjected to the environmental conditions of a high energy line break (HELB) is qualified by testing that includes saturated steam at 100% relative humidity. These test conditions exceed any exposure to either humidity or submergence during normal operations as understood in the context of "moisture."

Additionally, NUREG-0588, Rev. 1, specifically excludes humidity as an aging mechanism by stating the following in the aging discussion in Section 4 (8): "Effects of relative humidity need not be considered in the aging of electrical cable insulation."

Therefore, "moisture" is not considered to be an environmental stressor for EQ equipment.

RAI 4.4-2

In the LRA Section 4.4, the applicant stated that the Environmental Qualification Program manages component thermal, radiation, and wear cycle aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Appendix B -Aging Management Programs did not include Environmental Qualification Program as one of the existing programs. This program will be credited to manage the aging of EQ components. Please provide details of this program.

RNP Response:

New Section B.2.9 should be added to Appendix B as follows:

B.2.9 Environmental Qualification (EQ) of Electric Components

The RNP environmental qualification (EQ) program maintains the qualified life of the electrical equipment important to safety within the scope of 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." An aging limit (qualified life) is established for equipment within the scope of the RNP EQ program and an appropriate action, such as replacement or refurbishment, is taken prior to or at the end of the equipment qualified life so that the aging limit is not exceeded. Environmental qualification binders are maintained to demonstrate and document the qualified life of the equipment.

The RNP EQ program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet the requirements of 10 CFR 50.49. The RNP EQ program includes maintenance of supporting documentation, such as input information, references, calculations, analyses, EQ related correspondence, qualification test reports, and certifications.

<u>Evaluation</u>

<u>Scope of Program</u>

The RNP EQ program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

<u>Preventive Actions</u>

10 CFR 50.49 does not require actions that prevent aging effects. The RNP EQ program actions that could be viewed as preventive actions include (a)

establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit), (b) refurbishment, replacement, or requalification of installed equipment prior to reaching these aging limits, and (c) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain equipment aging effects within the qualification.

Parameters Monitored/Inspected

EQ component aging limits are not typically based on condition or performance monitoring. However, per Regulatory Guide 1.89, Rev. 1, such monitoring programs are an acceptable basis to modify aging limits. Monitoring or inspection of certain environmental, condition, or equipment parameters may be used to ensure that the equipment is within its qualification or as a means to modify the qualification.

Detection of Aging Effects

10 CFR 50.49 does not require the detection of aging effects for in-service components. Monitoring of aging effects may be used as a means to modify component aging limits.

Monitoring and Trending

10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging. EQ program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within its qualification or as a means to modify the qualification.

Acceptance Criteria

10 CFR 50.49 acceptance criteria is that an in-service EQ component is maintained within its qualification including: (a) its established aging limits, and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the aging limits of each installed device. When monitoring is used to modify a component aging limit, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

Corrective Actions

Corrective actions, including root cause determinations and prevention of recurrence, are done in accordance with the Corrective Action Program. Timeliness of corrective action is monitored.

Confirmation Process

Effectiveness of this AMP will be monitored using Corrective Action Program and quality assurance procedures, review and approval processes, and administrative controls which are implemented in accordance with the requirements of 10 CFR 50, Appendix B.

Administrative Controls

Corrective action and quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR 50, and will continue to be adequate for the period of extended operation.

Operating Experience

The RNP EQ program includes consideration of operating experience to modify qualification bases and conclusions, including aging limits. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during accident conditions after experiencing the detrimental effects of in-service aging.

Summary

Under 10 CFR 54.21c(1)(iii), EQ programs that implement the requirements of 10 CFR 50.49 are viewed as aging management programs for license renewal. The RNP EQ program complies with applicable regulations and manages component thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods, and provides reasonable assurance that the components within the scope of license renewal will maintain their intended function consistent with the current licensing basis for the period of extended operation. Therefore, this program is consistent with NUREG-1801, Section X.E1, "Environmental Qualification (EQ) of Electrical Equipment."

As a result of the above, a new LRA Subsection will be added as follows:

A.3.1.38 Environmental Qualification (EQ) of Electrical Components

The existing RNP EQ Program has been established in accordance with the requirements of 10 CFR 50.49. The program will adequately manage aging of

EQ equipment for the period of extended operation. Components that have been determined by EQ evaluation to have age-related limitations or restrictions are refurbished, re-qualified, or replaced prior to becoming incapable of performing their intended functions.

Table B.1 should be amended as follows:

GALL Program	RNP Program	App. B Subsection
	Gall Report Chapter X	
X.E1 Environmental Qualification (EQ) of Electrical Components	Environmental Qualification (EQ) of Electrical Components	B.2.9

RAI 4.4.1-1

In the LRA Section 4.4.1, the applicant stated that temperature and radiation values assumed for service conditions in the environmental qualification analyses are either the design operating values or measured values for Robinson Nuclear Plant (RNP). Please provide details about the design operating values and measured values. Provide assurance that measured values will not change due to operating conditions, time of the year, and other conditions described in RAI 4.4.1-2.

RNP Response:

The temperature and radiation values used for service conditions in the environmental qualification analyses discussed in LRA Section 4.4.1 are either the design values or are based on measured values. Design values are based on plant design documentation that supports the current licensing basis, including the UFSAR, design calculations, and EQ program evaluations. Measured values are actual measured values taken over a period of one year or more.

The pressurizer cubicle is the only area in the containment that uses actual measured temperatures, since temperatures in this area routinely exceed the bulk average containment temperature. Components located in the pressurizer cubicle that were found to be qualified for 60 years had sufficient margin to absorb the increases in normal operating temperatures in the pressurizer cubicle. These components included Rockbestos Firewall III cable and Raychem splice material.

Outside containment, the qualified life calculations are based on either the design temperature of 104°F or actual measured temperatures. Measured temperatures are based on temperature readings taken each shift by operations personnel. There are no defined harsh temperature areas in the EQ program outside of containment. In the one case where measured temperatures are used for EQ qualification, a qualified life of over 60 years resulted. Aging in this case was based on aging performed for PVC insulated cables that were then subjected to a LOCA. For these cables located outside containment, survival of a LOCA is not a requirement, which results in additional conservatism.

Area radiation levels are monitored continuously in various locations in the Containment and RAB. UFSAR Section 11.5 describes the Process and Effluent Radiation Monitoring System. Radiation levels in these areas are indicated, recorded, and alarmed in the control room.

Daily operator rounds, radiation monitoring by Health Physics personnel (surveys of areas in the RAB at least monthly, and in some cases daily or weekly), and Maintenance and Engineering personnel provide feedback to Engineering through the Corrective Action Program when changes to the plant environment or EQ equipment are encountered. Changes in temperature or radiation levels that could adversely affect qualification would be readily identified. RNP plant procedures govern the frequency of surveillances, radiation surveys, and plant walkdowns. The frequencies range from shiftly to each outage.

Containment temperature and radiation are logged at least daily, and other EQ areas are subject to operator rounds at least daily while the plant is operating. The temperature and radiation data obtained is representative of the service conditions of EQ equipment, and any change in temperature or radiation that could adversely affect qualification would be readily identified.

RAI 4.4.1-2

The LRA does not address whether there have been any major plant modifications or events at RNP of sufficient duration to cause the temperature and radiation values used in the underlying assumptions in the EQ calculations to be exceeded. Additionally, the LRA does not address whether the conservatism in the EQ equipment qualification analyses are sufficient to absorb environmental changes occurring due to plant modification and events. The LRA does not address the controls used to monitor changes in plant environmental conditions to periodically validate the environmental data used in analyses.

Please provide additional information on the following:

a) whether there have been any major plant modifications or events at sufficient duration to have changed the temperature and radiation values that were used in the underlying assumptions in the EQ calculations,

b) whether the conservatism in the EQ equipment qualification analyses are sufficient to absorb environmental changes occurring due to plant modification and events, and

c) the specific controls used to monitor changes in plant environmental conditions to periodically validate the environmental data used in analyses.

RNP Response:

a) RNP completed a new containment accident analysis in 1999 that resulted in revision of the temperature versus time profile used as a basis for environmental qualification. Also, RNP completed an Appendix K power uprate in 2002 that resulted in an approximate 1.7% increase in power level.

b) The qualification basis for the equipment impacted by the aforementioned changes had sufficient conservatism to maintain existing qualification.

c) Containment temperature and radiation are logged at least daily, and other EQ areas are subject to operator rounds at least daily while the plant is operating. The temperature and radiation data obtained is representative of the service conditions of EQ equipment, and any change in temperature or radiation that could adversely affect qualification would be readily identified.

UFSAR Section 11.5 describes the Process and Effluent Radiation Monitoring System. Radiation levels in these areas are indicated, recorded and alarmed in the control room.

Operator daily rounds, radiation monitoring by Health Physics personnel (surveys of areas in the RAB at least monthly, and in some cases daily or weekly), and Maintenance and Engineering personnel provide feedback to Engineering through the Corrective Action program when changes to the plant environment or EQ equipment are encountered. Changes in temperature or radiation levels that could adversely affect qualification would be readily identified. RNP plant procedures govern the frequency of surveillances, radiation surveys, and plant walkdowns. The frequencies range from shiftly to each outage.

RAI 4.4.1-3

In the LRA Section 4.4.1, the applicant stated that the wear cycle aging is a factor for some equipment within the EQ program. It is not clear to the staff why the wear cycle aging effect is not applicable to motors, limit switches, and electric connectors.

RNP Response:

Wear cycle aging for motors, limit switches, and electrical connectors is addressed below for the applicable portions of LRA Section 4.4.1.

EQDP 1.0, ASCO NP8316 and NP8321 Solenoid Valves (Applies to LRA Section 4.4.1.1)

<u>Wear Cycle Aging Analysis</u>

Extensive testing reported in the following two documents has demonstrated that wear aging is not an applicable aging mechanism for these solenoid valves:

1. Section 4.4 ("Wear Aging") of Test Report AQS-21678/TR (EQDP 1.0 Reference 1.1) states the following: "The valve samples were electrically cycled 40,000 times at maximum operating pressure differential using a control circuit."

2. Section 3.1.B of the enclosure to ASCO letter dated January 4, 1984 (see Attachment 1 in Section 8 of EQDP 1.0) states the following: "The valves were subjected to an accelerated life test of 500,000 operations at maximum operating pressure. At completion of the tests, the valves were functioning properly. Upon disassembly, visual inspection of the body parts revealed no indications of wear."

The assumed number of 1000 cycles per year shown in Section 3.2.1 of EQDP 1.0 is bounded with significant margin by actual testing. Since the SOVs that are normally energized are replaced after less than seven years of operation, they would not experience the pre-LOCA test conditions of 40,000 cycles. For those SOVs that normally are de-energized, an assumed operation of 1,000 cycles per year for 60 years represents only 12% of the test value of 500,000 cycles (after which there was no evidence of wear).

EQDP 1.1, ASCO Solenoid Valves (Applies to LRA Section 4.4.1.2)

Wear Cycle Aging Analysis

Extensive testing reported in the following two documents has demonstrated that wear aging is not an applicable aging mechanisms for these solenoid valves:

1. Section 4.1.1 ("Thermal Aging Simulation") of Test Report AQR-67368 (EQDP 1.1 Reference 1.3) describes the wear aging simulation of 2,080 cycles that was performed while the test specimens were being subjected to thermal aging (250°F for 438 hours). 1,900 cycles were performed during the first 24 hours of thermal aging; the remaining 180 cycles were spaced evenly throughout the remaining 414 hours of thermal aging.

2. Section 4.1.2 ("Wear Aging Simulation") of Test Report AQR-67368 (EQDP 1.1 Reference 1.3) describes the wear aging simulation of 18,020 cycles that was performed after the thermal aging exposure. The test specimens were energized at room ambient temperature, at a rate of 8 cycles per minute.

The entire wear aging exposure consisted of 20,100 cycles. Section 3.2.1 of EQDP 1.1 states that the assumed cycling conditions for these SOVs will consist of 10 cycles per year. Thus, the total number of 600 cycles in 60 years represents only 3% of the number of test cycles.

EQDP 8.0, Westinghouse RCFC Motors (Applies to LRA Section 4.4.1.10)

Wear Cycle Aging Analysis

The wear cycle for a motor is a start/stop cycle. Wear cycling is addressed in the WCAP-7829 test report; typically, the cycling done during testing is more severe than the cycling anticipated to occur during normal operations. Therefore, wear cycling does not have a significant impact on the qualified life of the equipment.

The motors are qualified by the testing reported in WCAP-7829 (EQDP 8.0, Reference 1.1). Page 16 (Two-Winding Test Procedures) of Reference 1.1 provides the following descriptions of wear aging testing that was performed:

- "The fan-loaded motor was started cold on the low-speed winding and transferred immediately to high-speed during the peak inrush. While still under heavy current, the motor was transferred back to the low-speed winding."

- "Many starts were made directly on the high-speed winding."

- "Dozens of transfers were later made in steam to remove doubt of possible adverse effect by sheer number of switching operations."

Appendix B ("Typical RCFC Motor Design Parameters") of Reference 1.1 gives the following design information concerning cycling:

Start Condition	*Permissible Starts Per Hour*
Motor at ambient temperature	4 for a 6-pole motor 4 for a 12-pole motor
Motor at rated total temperature	2 for a 6-pole motor 4 for a 12-pole motor

Thus, even when the motors are fully loaded, they could be started at least twice per hour (or 17,520 times per year). In fact, the Westinghouse motors qualified in this EQDP are rarely cycled. The reactor containment fan coolers powered by these motors operate in parallel during normal operation, and a minimum of two of the four should always be operating. Additional units are operated continuously depending on the plant heat load and other operating conditions.

Allowing for a conservative number of motor start/stop cycles for maintenance, in addition to normal operation and periodic performance tests, the number of start/stop cycles would not exceed 1000 for these motors over a 60-year plant life. Page 6-46 of EQDP 8.0 Reference 1.15 ("Power Plant Electrical Reference Series Volume 6, Motors"), states that a motor should be able to withstand 35,000 to 50,000 starts. Thus, the wear cycle aging effect is considered insignificant.

EQDP 8.1, Westinghouse Pump Motors (Applies to LRA Section 4.4.1.11)

Wear Cycle Aging Analysis

The wear cycle for a motor is a start/stop cycle. Wear cycling is addressed in the test report; typically, the cycling done during testing is more severe than the cycling anticipated to occur during normal operations. Therefore, wear cycling does not have a significant impact on the qualified life of the equipment.

The motors are qualified by the testing reported in WCAP-8754 (EQDP 8.1, Reference 1.1). Additionally, Section 4.6 ("Mechanical Cycling") of Reference 1.1, EQDP 8.1 states the following:

> *"The motor was line started with full load voltage and was run until full speed was achieved. The motor was immediately reversed until full speed was obtained. The power was then shut off and the rotor allowed to coast for one and one half minutes so that the rotor ring temperature was approximately 80°C. This cycling was done 500 times with each reversal, this amounted to a total of 1000 cycles. After the test, the stator was*

submerged in water and a ten-minute megger test was performed. The results of the second megger test indicated no change from the original megger test."

Attachment 3 Section 8,of EQDP 8.1 presents data furnished by Westinghouse for the RHR spare pump motor (300 HP, Model 506 UP). The data includes the following design information concerning cycling:

Start Condition	*Permissible Starts Per Hour*
Motor at ambient temperature	2
Motor at rated total temperature	1

Thus, even when the large motors are fully loaded, they could be started at least once per hour (or 8,760 times per year).

Allowing for a conservative number of motor start/stop cycles for maintenance, in addition to normal operation and periodic performance tests, the number of start/stop cycles would not exceed 1000 for these motors over a 60-year plant life. Page 6-46 of EQDP 8.1, Reference 1.15 ("Power Plant Electrical Reference Series Volume 6, Motors"), states that a motor should be able to withstand 35,000 to 50,000 starts. Thus, the wear cycle aging effect is considered insignificant.

EQDP 8.2, Westinghouse Motors – CS and SI Pump Motors (Applies to LRA Section 4.4.1.12)

<u>Wear Cycle Aging Analysis</u>

The containment spray pump motors are installed outside of containment and are not subjected to the effects of harsh accident environments. The motors have Westinghouse Class B – PMR ("Premium Moisture Resistance ") insulation, which is their standard insulation with an added protective feature. Westinghouse offered the following description in an undated (but pre-1983) price list: "PMR insulation system is developed by special manufacturing techniques and procedures employed to improve the moisture resisting qualities of the coated wound stator, so the complete insulation system will a have a minimum resistance of 1.5 megohms after 168 hours of testing in a humidity chamber maintained at 100% relative humidity and 40°C ambient. Outside diameter of rotor and inside diameter of stator are coated for extra protection."

General qualification for Westinghouse motors installed outside containment is established in WCAP-8754 ("Environmental Qualification of Class 1E Motors for Nuclear Out-of-Containment Use"), which states the following in Section 4.6:

"The motor was line started with full load voltage and was run until full speed was achieved. The motor was immediately reversed, until full

speed was achieved. The power was then shut off and the rotor allowed to coast for one and one half minutes, so that the rotor ring temperature was approximately 80°C. This cycling was done 500 times; with each reversal, this amounted to a total of 10000 cycles. After the test, the stator was submerged in water and a 10-minute megger test was performed. The results of the second megger test indicated no change from the original megger test."

These motors do not run during normal plant operation. They are tested periodically using a test loop to ensure operation in the event of a LOCA or HELB. Even if they were tested monthly, they would not be cycled more than 720 times during a 60-year life. Page 6-46 of EQDP 8.2, Reference 1.15 "Power Plant Electrical Reference Series Volume 6, Motors" states that this motor should be able to withstand 35,000 to 50,000 starts. Thus, wear aging is not a concern for these motors.

EQDP 34.0, Target Rock Solenoid Valves (Applies to LRA Section 4.4.1.45)

Wear Cycle Aging Analysis

Extensive testing reported in the following two documents has demonstrated that wear aging is not an applicable aging mechanism for these solenoid valves.

Section 3.1 ("Thermal Aging Test") of Test Report 3996 (EQDP 34.0, Reference 1.1) describes the wear aging simulation of 2,208 cycles that was performed while the test specimens were being subjected to thermal aging (280°F for 46 days).

Section 3.3 ("Wear Aging Test") of Test Report 3996 (EQDP 34.0, Reference 1.1) describes the wear aging simulation consisting of the following:

- 3300 cycles @ 108 Vac
- 3300 cycles @ 150 Vac
- 13,200 cycles @ 120 Vac

The combination of wear aging exposures consisted of 22,008 cycles. When the test valve was subjected to the post-test final operational test, the valve operated and functioned satisfactorily.

If the 22,008 cycles were performed at even intervals throughout the 60-year qualified life of the valve, then the valve would be cycled 367 times each year (or approximately once per day). Since the SOVs are normally only cycled for testing and for head venting during outages, the wear aging performed as part of the test exceeds the expected actual wear.

EQDP 18.0, Westinghouse CET/CCM – Incore T/C Connectors (Applies to LRA Section 4.4.1.31)

Wear Cycle Aging Analysis

According to Section 2.0 of EQDP 18.0, Reference 1.1, the T/C connector assemblies were left intact for test monitoring purposes. This condition is consistent with normal plant operations, since the connectors are normally only disconnected during refueling outages. The connectors were installed in 1987, so they would only be disconnected approximately 25 times during their entire installed life, if the plant operates for 60 years.

Therefore, wear cycle aging is not a factor for these components.

EQDP 24.0, Barton Pressure Switches - Model 580a (Applies to LRA Section 4.4.1.37)

Wear Cycle Aging Analysis

The installed equipment items are calibrated semi-annually.

According to the response to Question 8 of Section 3.3.4 of this EQDP, the following mechanical aging was performed on the tested equipment:

- 15,000 cycles were performed with electrical load.
- 48,285 cycles were performed without electrical load.

Thus, the installed equipment could be cycled at least 250 times each year for 60 years. The 48,285 non-energized cycles provides additional margin. Thus, wear cycle aging is not a significant concern for this equipment.

EQDP 25, Namco EC210 Connector Assemblies (Applies to LRA Section 4.4.1.38)

Wear Cycle Aging Analysis

Section 6.1 ("Aging Simulation") of QTR-145 (EQDP 25, Reference 1.1) and QTR-142 (EQDP 25, Reference 1.2) both state the following:

> *"Although the test items were mounted on a limit switch which was mechanical wear aged, an engineering review of the receptacle and connector design concluded that mechanical aging was not a factor in the life of these components due to normally limited removal and assembly requirements (usually less than 10 per life time)."*

The wear cycle for a connector is a mate-demate cycle and the EQ consideration is the effect on the sealing surfaces of the connector. Page 12-3 of QTR-142 states that these connectors have o-rings made of EPDM, which are easily inspected for flaws each mate-demate cycle. Thus seal qualification is based on inspection or replacement of the o-ring rather than the number of mate-demate cycles. Therefore, wear cycle aging is not considered to be a factor for these components.

EQDP 38.0, Honeywell V4-21 Microswitch Assemblies *(Applies to LRA Section 4.4.1.47)

Wear Cycle Aging Analysis

The V4-21 switch is located on a flow indicating controller in the pipe alley and is only required to operate during a LOCA inside containment. It is calibrated each refueling cycle.

The V4-21 switch is no longer supplied by Honeywell, but the current "V" family of switches (for example V3, V5, V7) is one of several types of switches that Honeywell designates as a "basic" switch. Specific operational performance limits for cycling could not be obtained for the "V" family of switches, but were available for the "B" type, which is also designated by Honeywell as a "basic" switch. Page 97 of the electronic catalogue available on the Honeywell website (February 2003) states the following concerning the "B" type switches:

> *"Micro Switch believes that with the following voltage and current values and under the test conditions set forth below switch life of 100,000 closures, under 95% survival can be expected. It is a starting point for user evaluation and provides guidelines on the switches identified."*

If an extremely conservative assumption is made that the basic "V" switch can only cycle 1% of the amount of the basic "B" switch, then the "V" switch could be expected to cycle 1,000 times with 95% survival. If the installed equipment is calibrated during each refueling cycle, then the total number of cycles during the 60-year life of the plant could not be expected to exceed 40, which is 4% of the expected number of 1,000 cycles. Thus, wear cycle aging is not a concern for the V4-21 switches.

RAI 4.4.1-4

In the LRA Section 4.4.1, the applicant stated that the thermal, radiation, and wear cycle aging effects were evaluated. Moisture is an environmental stressor. It is not clear to the staff if the aging effect due to moisture was addressed in the LRA.

RNP Response:

See the RNP Response to RAI 4.4-1.

RAI 4.4.1-5

Please provide details regarding total integrated dose through the period of extended operation from the 40-year values.

RNP Response:

The RNP Environmental Qualification Program has established bounding radiation dose qualification values for environmentally qualified components. Typically, these bounding radiation dose values were determined by component vendors through testing. To verify that the bounding radiation values are acceptable for the period of extended operation, integrated dose values were determined and then compared to the bounding values. The total integrated dose through the period of extended operation is determined by adding the established accident dose to the normal operating dose for the component. The normal operating dose was determined by multiplying the normal 40-year dose by 1.5 to determine the 60-year normal dose.

RAI 4.4.1-6

For normally de-energized solenoids, the RNP calculations (EQDP-1.0, Rev. 9, and EQDP-1.1, Rev. 2) assumed these valves are normally de-energized and the energization time during testing of the valves was considered to be insignificant from an aging standpoint. The staff discussed the potential impact of energization during the testing of these valves and its effect on the time-limited aging analysis (TLAA). Please determine the impact of testing on the qualified life calculation of these valves.

RNP Response:

See the RNP Response to RAI 4.4.1-3.

RAI 4.4.1-7

Motor aging due to a wear cycle is not addressed in 4.4.1.11 (EQDP - 8.1, Rev. 6). Please explain the reason.

RNP Response:

See the RNP Response to RAI 4.4.1-3.

RAI 4.4.1-8

The qualification of Westinghouse CET/CCM - reference junction boxes and potting adaptors (4.4.1.32) - has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The calculation stated that the potting adaptors are required to be replaced every 29 years. Please investigate this issue.

RNP Response:

LRA Section 4.4.1.32, Westinghouse CET/CCM – Reference Junction Boxes and Potting Adaptors, makes the following statements:

> **"Thermal Considerations**
>
> The qualified life of the equipment is calculated to be greater than 47 years at the current operating conditions. Based on the installation of this equipment in 1987, this qualified life is sufficient for the entire period of extended operation. There are no self-heating effects for this instrumentation application (thermocouple signals). The potting adaptors have a qualified life of 29 years. Therefore, replacement of these adaptors before the end of their qualified life is an EQ maintenance requirement.
>
> **Conclusion**
>
> Westinghouse CET/CCM – Reference Junction Boxes and Potting Adaptors are qualified at Robinson Nuclear Plant (RNP) to the end of the period of extended operation."

The statement in the Conclusion that the Reference Junction Boxes and Potting Adaptors are qualified through the period of extended operation is based on the requirement that the potting adaptors are replaced every 29 years, as stated in the Thermal Considerations. The conclusion statement applies to the assembly that is comprised of the reference junction box and the potting adaptors.

RAI 4.4.1-9

EQDP-31.0, Rev. 6, was reviewed and it was found that all power cables addressed by the package are energized for short durations, resulting in negligible ohmic heating effects. Please provide additional discussion of the short duration periods that power cables are energized in section 4.4.1.43 of the LRA.

RNP Response:

The Thermal Considerations discussion in LRA Section 4.4.1.43, PVC and XLPE Cables, contains the following statement:

> **"Thermal Considerations**
>
> The qualified life of the cables is calculated to be greater than 60 years at the current operating conditions. There are no self-heating effects for these cables. There are no EQ maintenance requirements."

This should be amended as follows:

> **"Thermal Considerations**
>
> The qualified life of the cables is calculated to be greater than 60 years at the current operating conditions. The service of each power cable was reviewed to determine the ohmic heating contribution to cable life. In those cases where operation was intermittent and of short duration, such as motor operated valve applications, ohmic heating was considered to be insignificant. In those cases where operation was infrequent but of longer duration, such as pump motors, the frequency and time of operation was used to calculate the ohmic heating contribution to cable aging.
>
> There are no EQ maintenance requirements."

RAI 4.4.1-10

The target rock solenoid valves (EQDP-34.0, Rev. 6) package did not list voltage and effects of solenoid cycling on aging. Please explain this issue.

RNP Response:

EQDP 34.0 has been revised to include the solenoid operating voltage.

See the RNP Response to RAI 4.4.1-3 for additional discussion on wear cycle aging.

RAI 4.4.1-11

Sections 4.4.1.13, 4.4.1.26, and 4.4.1.37 of the LRA listed a normal dose as 10^3 rads, rather than 10^6 rads as used for other equipment nearby. Please investigate the issue.

RNP Response:

Section 4.4.1.13 which addresses Crouse – Hinds penetrations, identifies the normal dose as 3.45×10^3 rads. A review of plant design documents found that this is the correct value for the penetrations located in the containment.

The Kerite HTK Power Cable addressed in LRA Section 4.4.1.26 is used for one application inside the containment. This cable is routed from the penetrations to the containment ventilation units. A review of plant design documents found that the normal dose of 3.45×10^3 rads reflects the highest dose in the area of this cable.

The Barton Pressure Switches addressed in LRA Section 4.4.1.37 are located in the RAB. The normal dose used, 5.26×10^4 rads gamma, is equivalent to 0.1 rad/hr. for 60 years. This is the dose rate for a high radiation area as defined by 10 CFR 20.1003. This is considered to be a conservative assumption for the Charging Pump Room in the RAB. Plant documentation shows the normal dose in this area as negligible.

RAI 4.5-1

From the TLAA provided in Section 4.5 of the LRA, it is not clear as to the relative magnitudes of the changes in the various factors affecting the prestressing loss and remaining prestressing force levels. The applicant is requested to provide a table showing the initial average prestressing force, losses due to the five factors (indicated by bullets in the TLAA), the final average prestressing force originally considered at forty years, and the values proposed at the end of the extended period of operation.

RNP Response:

The original design for the grouted tendons was based on a 50-year value, so the final average values shown below for both 50 and 60 years.

Description	Initial Value	Value After One Year	Value After 50 Years	Value At 60 Years
Prestress losses due to concrete shrinkage	N/A	4002 psi	1998 psi	0
Prestress losses due to concrete creep	N/A	6317 psi	3153 psi	0
Prestress losses due to tendon relaxation	N/A	6000 psi	2400 psi	1800 psi
Prestress losses due to elastic shortening	2104 psi	N/A	N/A	N/A
Tendon Prestress	120,000 psi	103,680 psi	96,128 psi	94,328 psi
**Minimum Required Prestress	91,726 psi	91,726 psi	91,726 psi	91,726 psi

**2% tendon breakage is conservatively factored into the Minimum Required Prestress value. The 2% tendon breakage from ACI is primarily associated with wire rope tendons; the RNP tendons are 1-3/8" diameter steel bars. Therefore, breakage would be immediately identified during the tensioning process.

The containment exterior wall concrete was stressed to approximately 526 psi when the tendons were tensioned. This is a relatively low level for concrete with a 4000 psi design strength; the portion of the exterior wall at the tendon load block actually has a 5000 psi design strength. Because of these factors, the creep rate and total creep will tend to be low.

The tendons were initially tensioned in late March/early April 1970, and then re-tensioned in May 1970. The last exterior wall concrete lifts were placed in

December 1969 and the first lifts were placed in November 1968. Because of the delay in tendon tensioning from final concrete set to actually tensioning, the creep rate and total creep will tend to be lower.

The tendons are considered to be post-tensioned because they were not loaded until after the concrete was placed. This allows a portion of the shrinkage to occur before tendon tensioning. The longer time between concrete placement and tendon tensioning, the more concrete hydration takes place. Therefore, the rate and total creep are reduced.

RAI 4.5-2

Information Notice 99-10, Revision 1, Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment," describes the experience related to hydrogen stress cracking of ASTM A 421 wires, and breakage of AISI 4140 anchor-heads due to hydrogen stress cracking. However, these incidents were detected and corrective actions were taken as the tendon components were amenable for inservice inspection, component replacement, and re-tensioning, as required.

> The RNB tendon components (i.e., AISI 5160 bars, AISI 4130 couplers, and AISI 8620 grip nuts) are high hardness components, subjected to sustained high stresses, and hydrogen stress cracking of the high hardness components is a plausible aging effects in presence of galvanized tendon ducts around the grouted tendon components. As recognized by the applicant in Revision No. 15 of the Updated FSAR (p. 3.8.1-56), the results of the two surveillance blocks cannot be relied upon to provide confidence regarding the plausibility of such aging effects, or the time dependant trending of prestressing forces. Moreover, no such surveillance blocks are available for the future prediction of the containment tendon behavior.

In light of the above discussion, the applicant is requested to explore the methods that can be used to assess the containment prestessing levels during the extended period of operation.

RNP Response:

NRC IN 99-10 addresses accessible prestressing tendon systems and does not provide details associated with a prestressing system completely encased in grout. Additionally, the tendon systems referenced in the IN were covered with grease; a common factor in several reported failures of threaded fasteners due to SCC appears to be the use of lubricants containing molybdenum disulfide. Laboratory tests indicate that H_2S may be released from molybdenum disulfide decomposition in aqueous environments. SCC is a type of corrosive attack that occurs through the combined actions of stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. Elimination or reduction in any of these three factors will decrease the likelihood of stress corrosion cracking. The material yield stress values for the subject tendons is below the 150 ksi value identified for materials susceptible to stress cracking. Additionally, the tendons, couplers, and grip nuts are completely encased in a highly alkaline grout, and therefore are not in the corrosive environment required for SCC to occur. Section 3.8.1.6.1.3 of the UFSAR discusses the cathodic protection afforded the tendons by the galvanized containment pipe and describes the design as the ideal level of protection since it automatically operates below the hydrogen overvoltage potential at which free hydrogen is evolved at the surface of the protected tendons. Therefore, only one of the three factors (tensile stress) required for SCC is present; as such, it is not a credible aging effect for the RNP tendons.

The referenced section of the UFSAR specifically states: "There is no practical method of surveying the tendon stress and corrosion, creep and shrinkage of the concrete for a grouted tendon. Known conservative analytical procedures, in addition to successful experience application for grouted tendons, do not warrant a surveillance program." The UFSAR also states: "However, two surveillance tendons similar to the service tendons and in a similar environment are provided." Additional information in this regard is provided in the RNP Response to RAI 4.5-1.

As stated in the UFSAR, the design basis for the tendons is a combination of analyses and successful experience for grouted tendons. The surveillance tendons were provided for additional assurance of the original assumptions, which have been validated based on the inspected condition of the surveillance tendons for both 5 and 25 years. Given that after 5 and 25 years the surveillance tendons experienced essentially no corrosion, in combination with the acknowledged corrosion resistance of steel embedded in concrete/grout, it is reasonable to assume that corrosion of the RNP tendon system will be negligible through the period of extended operation.

In addition, the structural integrity of the containment structure has been verified by performing Structural Integrity Tests (SITs) as required by the Technical Specifications. A preoperational SIT was performed in 1970 at 48.3 psig (1.15 X design pressure), and subsequent SITs were performed in 1974 and 1992 at 42 psig (design pressure). Satisfactory SIT results and comparisons between the data taken were summarized in a letter from D. McCarthy (CP&L) to the NRC, Serial: NLS-92-262: "Containment Structural Integrity Test," dated October 7, 1992.

A review of Regulatory Guide 1.90, "Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons," was performed to consider any additional verification methods that might be available for grouted tendons. Implementation of this RG would have involved performing SITs at 1.15 times design pressure, and at the calculated peak internal pressure (Pa) associated with the design basis accident, during the plant life. RG 1.90 addresses grouted tendons, however, it is primarily associated with cable wire tendons and specifically states it is not directly applicable to bar tendons. Additionally, the RG is structured such that compliance would require enhancement of the tendon construction details and is not conducive to the existing design. However, the areas measured for deformation and the visual examination areas in RG 1.90, Alternative B, "Monitoring of Deformation Under

Pressure," are similar to those required by the RNP SITs which have been already performed.

In addition, a visual examination of 100% of the accessible reinforced concrete exterior surface of the containment structure has been completed with satisfactory results in accordance with ASME Code, Section XI, Subsection IWL, to verify structural integrity [refer to the RN:P letter from B. L. Fletcher III (CP&L) to NRC, Serial RNP-RA/02-0086: "Response to Request for Additional Information on Amendment Request Regarding One-Time Extension of Containment Type A Test Interval (TAC No. MB4658)," dated June 19, 2002].

As shown in the RNP Response to RAI 4.5-1, the prestressing levels have been determined analytically to be sufficient through the period of extended operation. SITs performed in 1970, 1974, and 1992 verified the structural integrity of the containment structure. The IWL Program requires inspection of the accessible concrete surfaces and will be continued through the extended life of the plant. The Tendon Surveillance Program validated the effectiveness of the grout to prevent corrosion of the tendons. However, to provide additional assurance of the tendons design capacity, testing (at integrated leak rate test pressure) similar to the SIT performed in 1992 will be scheduled to coincide with Appendix J containment integrated leak rate testing conducted during the period of extended operation (required frequency in accordance with 10 CFR 50 Appendix J). The monitoring criteria for these tests will be limited to deformations and cracking associated with the vertical prestressed tendons, and will not include radial monitoring. Guidelines for performing the IWL examinations for these tests will include additional emphasis on looking for a pattern of horizontal cracks, and additional cracking in the discontinuity areas. The proposed tests, in conjunction with the analytical determination of tendon prestress, the established corrosion resistance of the embedded tendons, the previously completed SITs, and the ongoing inspections of concrete performed by the IWL Program, provide adequate validation of the tendon structural integrity.

As a result of the above response, the following paragraph to is added LRA Subsection A.3.2.4, Containment Tendon Loss of Prestress:

> "To provide additional assurance of the tendons design capacity, testing (at integrated leak rate test pressure), similar to the Structural Integrity Test performed in 1992 will be scheduled to coincide with Appendix J containment integrated leak rate testing conducted during the period of extended operation (required frequency in accordance with 10 CFR 50, Appendix J). The monitoring criteria for these tests will be limited to deformations and cracking associated with the vertical prestressed tendons, and will not include radial monitoring. Guidelines for performing the IWL examinations for these tests will include additional emphasis on looking for a pattern of horizontal cracks, and additional cracking in the discontinuity areas."

RAI 4.5-3

The applicant is requested to justify why the information sought in RAI 4.5-1 should not be included in the UFSAR Supplement. Such information would clearly show the expected average prestressing force level in the tendons, and in the concrete of the containment during the extended period of operation. If such information is not included in the UFSAR, where do you propose to present it.

RNP Response:

Prior to the period of extended operation, information from the RNP Response to RAI 4.5-1 will be incorporated into Section 3.8.1.4.7 of the UFSAR. This will include initial average prestressing force, losses, and final average prestressing force, as discussed in the RNP Response to RAI 4.5-1. This information supercedes the proposed changes shown on LRA Page A-6 for UFSAR Section 3.8.1.4.7.

RAI 4.6.1-1

A review of the NRC's Agencywide Documents Access and Management System (ADAMS) indicates that WCAP-15628 has not been submitted for review and approval by the staff. Either submit the report for NRC staff review and approval, or, as an alternative, discuss how the fracture analysis assessment for the leak-before-break (LBB) analysis accounts for potential loss of fracture toughness properties due to thermal aging of the RCS main loop piping, pump or valve components made from CASS. If the alternative option is selected, include in this discussion, a discussion as to how the 40-year design basis thermal transients for RNP bound the fracture mechanics analyses for the RCS main loop piping through the expiration of the extended operating period for RNP, after taking into account potential loss of fracture toughness due to thermal aging. Also include all appropriate quantitative data that will enable the staff to perform an independent verification of the validity of the LBB analysis through the expiration of the extended period of operation for RNP. This last Item is requested to enable to the staff to meet Advisory Committee for Reactor Safeguards committee-member expectations on staff reviews of time-limited aging analyses.

RNP Response:

The requested WCAP will be submitted under a separate cover letter.

RAI 4.6.1-2

ASME Code Case N-481 has been accepted by the staff in Regulatory Guide (RG) 1.147, Revision 12, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1," as an acceptable alternative inservice inspection methodology for RCP casings. To support the alternative visual examination methods of Code Case N-481, the Code Case states that a fracture mechanics evaluation is required that incorporates the following seven evaluation elements:

1. a stress analysis for the pump casing
2. a review of the operating history for the pump
3. postulation of an existing reference flaw that has a flaw-depth equal to one-quarter the pump casing thickness and a flaw length equal to six times the postulated flaw depth (i.e., a quarter-thickness flaw that has an aspect ratio of 6:1)
4. establishment of stability criteria for the postulated flaw under the governing stress conditions
5. that considers the effects of thermal aging embrittlement and any other processes or mechanisms that may degrade the properties of the pump casing during service.

Clause *(e)* in Code Case N-481 also indicates that this fracture mechanics evaluation is to be "submitted to the regulatory and enforcement authorities having jurisdiction at the plant site for review." In Section 4.6.1 of the LRA, CP&L stated WCAP-15363, Revision 1, was issued by Westinghouse as the evaluation to support use of the alternative visual examinations methods in ASME Code Case N-481 for the RNP reactor coolant pump (RCP) casings during the extended period of operation. A review of the NRC's Agencywide Documents Access and Management System (ADAMS) indicates that WCAP-15363, Revision 1, has not been submitted to the staff for review. Pursuant to Clause *(e)* of ASME Code N-481, submit WCAP-15363, Revision 1, for review if the Code Case is desired to be used as an alternative methodology for the RNP RCP casings during the extended period of operation.

RNP Response:

WCAP-15363, Revision 1, will be submitted under a separate cover letter.

RAI 4.6.1-3

CP&L's FSAR Supplement summary descriptions for the TLAAs on thermal aging of CASS, as given in Sections A.3.2.5.1 and A.3.2.5.2 of Appendix A to the LRA, indicate that the TLAAs are in compliance with the requirements of 10 CFR 54.21(c)(1)(ii); however, the TLAAs are based on WCAP reports that have been issued to demonstrate validity of prior-existing 40-year analyses for the period of extended operation for RNP. Confirm that the FSAR Supplement summary descriptions for the TLAAs of thermal aging of CASS, as given in Sections A.3.2.5.1 and A.3.2.5.2 of Appendix A to the LRA, should indicate compliance with the requirements of 10 CFR 54.21(c)(1)(i) instead, and not to the requirements of 10 CFR 54.21(c)(1)(ii). In addition, amend your FSAR Supplement summary descriptions for the TLAAs of thermal aging of CASS, as given in Sections A.3.2.5.1 and A.3.2.5.2 of Appendix A to the LRA, to reflect the information provided in CP&L's responses to RAIs 4.6.1-1 and 4.6.1-2 when the responses are submitted under oath and affirmation to the NRC document control desk.

RNP Response:

The analysis described in UFSAR Supplement, Appendix A, section A.3.2.5.1, for the leak-before break of reactor coolant system piping states that the 40-year design basis thermal transients have been shown to be conservative for the 60-year operating period. However, the analysis performed for the license renewal period incorporates plant-specific material property data, adjustments to material property data to account for changes projected to occur during the license renewal period, and demonstrates applicable margins on flaw size and stability. As such, it is concluded that the analysis has been projected to the end of the period of license renewal, consistent with 10 CFR 54.21(c)(1)(ii), as stated in the license renewal application.

The analysis described in UFSAR Supplement, Appendix A, section A.3.2.5.2, for fracture mechanics analysis for reactor coolant pump states that the analysis performed for license renewal uses the limiting transients from the 40-year design transient set. However, the analysis performed for license renewal uses plant-specific material property data for the reactor coolant pump castings, adjusted to allow for reduction in fracture toughness during the 60-year operating period. As such, it is concluded that the analysis has been projected to the end of the period of license renewal, consistent with 10 CFR 54.21(c)(1)(ii), as stated in the license renewal application.

Therefore, changes to UFSAR Supplement, Appendix A, sections A.3.2.5.1 and A.3.2.5.2, are not considered necessary.