March 5, 2003

LICENSEE: Progress Energy

FACILITY: H. B. Robinson Steam Electric Plant, Unit 2

SUBJECT: SUMMARY OF DECEMBER 17, 18, AND 19, 2002, AND JANUARY 8, 2003, MEETING AND TELEPHONE CONFERENCE ON JANUARY 16, 2003, WITH PROGRESS ENERGY CONCERNING REQUESTS FOR ADDITIONAL INFORMATION PERTAINING TO THE H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2, REFERRED AS ROBINSON NUCLEAR PLANT (RNP) LICENSE RENEWAL APPLICATION

On December 17, 18, and 19, 2002, and January 8, 2003, the Nuclear Regulatory Commission (NRC) staff (the staff) met with members of the Progress Energy in a number of public meetings and on January 16, 2003, held a telephone conference to discuss the staff's draft requests for additional information (RAI) regarding the license renewal application (LRA) for the Robinson Nuclear Plant (RNP). The list of attendees is enclosed.

The meeting was useful in clarifying the intent of the staff's draft RAIs. Several of these draft RAIs were resolved, while the balance will formally be sent to the applicant. The resolution of draft RAIs was based on information available in the license renewal application or in other docketed material.

The applicant has had an opportunity to review and comment on this summary.

Enclosure 1 provides a lists of attendees. Enclosure 2 contains a listing of the draft RAIs discussed with the applicant including a brief description on the status of the item and the basis for resolving or disposing of the draft RAIs that will not be issued as a final RAI to the applicant.

/***RA***/

Sikhindra K. Mitra, Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-261

Enclosures: As stated

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LICENSEE: Progress Energy

FACILITY: H. B. Robinson Steam Electric Plant, Unit 2

SUBJECT: SUMMARY OF DECEMBER 17, 18, AND 19, 2002, AND JANUARY 8, 2003, MEETING AND TELEPHONE CONFERENCE ON JANUARY 16, 2003, WITH PROGRESS ENERGY CONCERNING REQUESTS FOR ADDITIONAL INFORMATION PERTAINING TO THE H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2, REFERRED AS ROBINSON NUCLEAR PLANT (RNP) LICENSE RENEWAL APPLICATION

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/***RA***/

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Office of Nuclear Reactor Regulation

Docket No.: 50-261
Enclosures: As stated

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Meeting Attendance List

December 17, 2002 Room 13B2

Name	**Organization**
Amar N. Pal	DE/EEIB
S.K. Mitra	DE/RLEP
Kimberley Corp	DRIP/RLEP
Bob Reynolds	CP&L
Talmage Clements	CP&L
Michael Fletcher	CP&L
Roger Stewart	CP&L
Michael Heath	CP&L
Greg S. Gelbeth	NRC/NRR/DIPM/IEMB
Bill Rogers	NRC/NRR/DIPM
Sam Miranda	NRC/NRR/SRXB
John Lehning	NRC
Sam Lee	NRC/NRR/DRIP/RLEP
Raj Goel	NRC/NRR/SPLB
Steve Jones	NRC/NRR/SPLB
Hans Ashar	EMEB/DE/NRR
John Ma	EmEB/DE/NRR
David C. Jeng	EMEB/DE/NRR

December 18, 2002 Room 11B2

Name	**Organization**
Bob Reynolds	CP&L
Talmage Clements	CP&L
Michael Fletcher	CP&L
Roger Stewart	CP&L
Michael Heath	CP&L
J.K. Milton	NRR/RCED
D.M. Frumkin	NRR/DSSA
Kimberley Corp	NRR/DRIP/RLEP
Ralph Architzel	NRR/DSSA
Jim Strnisha	NRR/DE
Vince Klco	NRR/DSSA
Y.C. (Rena) Li	NRR/DE
Pei-Ying Chen	NRR/DE
Ken Chang	NRR/DE/EMEB
John Tsao	NRR/DE/EMCB
Ktis Parczewski	NRR/DE/EMCB
Pat Patnaik	NRR/DE/EMCB
Carolyn Lanom	NRR/DE/EMCB

Meeting Attendance List

December 19, 2002 Room 12B2

Name	Organization
Roger Stewart	CP&L
James Medoff	NRC
Michael H. Fletcher	CP&L
Talmage Clements	CP&L
Michael Heath	CP&L
Kimberley Corp	RLEP
S.K. Mitra	NRR/RLEP
Ken Chang	NRR/DE/EMEB
Stewart Bailey	EMEB
John S. Ma	EMEB
Mark Hartzman	EMEB
John Tsao	NRR

January 8, 2003 Room O-13B2

Name	Organization
Talmage Clements	Progress Energy
Michael H. Fletcher	Progress Energy
Roger Stewart	Progress Energy
S.K. Mitra	RLEP
Arnold Lee	NRR/DE/EMEB
Kimberley Corp	RLEP
James Medoff	NRR/DE/EMCB
John Tsao	NRR/DE/EMCB
Sam Miranda	NRR/DSSA/SRXB
Stewart Bailey	NRR/DE/EMEB
Ken Chang	NRR/DE/EMEB
Ram Subbaratnam	NRR/RLEP
Bill Rogers	NRR/DIPM/IEHB

Conference Call Attendance List

January 16, 2003 Room O-12B2

Michael H. Fletcher	Progress Energy
Roger Stewart	Progress Energy
Jan Kozyra	Progress Energy
S.K. Mitra	RLEP
Arnold Lee	NRR/DE/EMEB

SUMMARY OF DECEMBER 17, 18, AND 19, 2002, AND JANUARY 8, 2003, MEETING AND TELEPHONE CONFERENCE ON JANUARY 16, 2003, WITH PROGRESS ENERGY

On December 17, 18, and 19, 2002, and January 8, 2003,the Nuclear Regulatory Commission (NRC) staff (the staff) met with members of the Progress Energy in a number of public meetings and on January 16, 2003, held a telephone conference to discuss the staff's draft requests for additional information (RAI) regarding the license renewal application (LRA) for the Robinson Nuclear Plant (RNP). The following draft RAIs were discussed during meetings and conference call. A general note (Note 1) is used in response to the RAI. The meaning of the note is:

Note 1: Based on the discussion, Progress Energy indicated RAI was clearly understood and would be responded in its entirety.

2.1.1, 2.1.2 Scoping and Screening Methodology

2.1.1-D1 By letters dated December 3, 2001, and March 15, 2002, the Nuclear Regulatory Commission (NRC) issued a staff position to the Nuclear Energy Institute (NEI) which described areas to be considered and options it expects licensees to use to determine what systems, structures, or components (SSCs) meet the 10 CFR 54.4(a)(2) criterion (i.e., All non safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i),(ii),(iii) of this section.)

The December 3rd letter provided specific examples of operating experience which identified pipe failure events (summarized in Information Notice (IN) 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor") and the approaches the NRC considers acceptable to determine which piping systems should be included in scope based on the 54.4(a)(2) criterion.

The March 15th letter, further described the staff's expectations for the evaluation of non-piping SSCs to determine which additional non safety-related SSCs are within scope. The position states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's CLB, engineering judgement and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports such as significant operating experience reports (SOERs), and engineering evaluations.

Consistent with the staff position described in the aforementioned letters, please describe your scoping methodology implemented for the evaluation of the 10 CFR 54.4(a)(2) criterion. As part of your response please indicate the option(s) credited, list the SSCs included within scope as a result of your efforts, list those SCs for which aging management reviews were conducted, and for each SC describe the aging management programs, as applicable, to be credited for managing the identified aging effects.

Response: Note 1.

2.1.1-D2 During the audit of the H.B. Robinson scoping and screening methodology, the audit team determined that the procedures reviewed in combination with the review of a sample of scoping and screening products provided adequate evidence that the scoping and screening process was conducted in accordance with the requirements of 10 CFR 54.4, "Scope," and 10 CFR 54.21, "Contents of Application — Technical Information." Additionally, the staff discussed the applicant's position concerning the potential long-term program implementation of the LRA methodology and guidance into the operational phase of the plant during the extended period of operation. As a result, the team concluded that the applicant needs to formally document the process it intends to implement to capture the scoping and screening process upon which the applicant will rely during the period of extended operation at H.B. Robinson to satisfy the requirements of 10 CFR 54.35, "Requirements During the Term of Renewed License."

Response: Note 1.

2.1.1-D3 During the audit of the H.B. Robinson scoping and screening methodology, the audit team determined that the system and component intended functions had been identified in the system design basis documents. However, during the scoping process, the intended functions had been grouped and reworded (relative to the intended functions contained in the design basis documents) when listed on the scoping worksheets. The audit team discussed the process with the applicant's staff and reviewed the process implementation guidance developed by the applicant, however, the audit team was unable to determine the methods used for the grouping and rewording of the intended functions. In addition, the audit team could not discern a clear, auditable trail from the intended functions, as listed in the design basis documents, to the grouped and reworded intended functions listed on the scoping worksheets. As a result, the team concluded that the applicant needs to formally document the process used to transfer and maintain the content of the intended functions, as listed in the design basis documents, to the grouped and reworded intended functions listed on the scoping worksheets.

Response: Note 1.

2.1.2-D1 The applicant describes its process of evaluating consumables in Section 2.1.2 of the application. The applicant states that the evaluation process for consumables is consistent with the NRC staff guidance on consumables provided in a letter from C.I. Grimes, NRC to D.J. Walters, NEI dated March 10, 2000. The applicant should state whether their evaluation process for consumables is also subject to screening guidance in accordance with

NUREG-1800, Table 2.1-3 dated April 2001. If consumables are not considered subject to NUREG-1800 scoping and screening guidance, provide a justification for their exclusion.

Response: Note 1.

2.3.1.3 Pressurizer

2.3.1.3-D1 Table 3.1-1 states, "The Pressurizer Spray Head performs no license renewal intended functions at RNP." Please confirm that the spray head is not relied upon to function, either with normal or auxiliary spray, following a postulated fire in accordance with the requirements of Appendix R to 10 CFR 50, or after a postulated steam generator tube rupture event.

Response: Note 1.

2.3.1.6 Steam Generator

2.3.1.6-D1 Table 3.1-1 states, "... the feed rings/J-nozzles perform no license renewal intended functions." The staff's view is that they provide structural and/or functional support for in-scope equipment. Please justify the exclusion of these components from the LRA aging management requirements.

Response: Note 1.

2.3.2.3 Containment Spray System

2.3.2.3-D1 On piping and instrumentation diagram 5379-1082LR Sheet 3, at grid location G-7, vacuum breakers SI-899D and SI-899E are highlighted as being within the scope of license renewal. These vacuum breakers appear to protect the integrity of the containment spray additive tank in support of the containment spray system's iodine removal intended function. However, LRA Table 2.3-4, which lists the components and commodity groups of the containment spray system that are subject to an AMR, does not include a specific entry for vacuum breakers. Therefore, the applicant is requested to either (1) identify the component/commodity group in LRA Table 2.3-4 that generically includes vacuum breakers (e.g., valves, piping, tubing, and fittings), (2) include an additional entry in LRA Table 2.3-4 for vacuum breakers, or (3) justify the exclusion of vacuum breakers SI-899D and SI-899E from an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.3-D2 On piping and instrumentation diagram 5379-1082LR Sheet 5, containment spray header nozzles are highlighted as being within the scope of license renewal. It appears that these nozzles are credited with both forming a pressure boundary for the containment spray system flowpath and inducing the spray flow that is relied upon in the safety analysis (e.g., UFSAR Section 6.2.2.3.1) to ensure that adequate containment heat removal occurs. However, LRA Table 2.3-4, which lists the components and commodity groups of the containment spray system that are subject to an AMR, does not appear to include an entry that encompasses the intended functions of the spray nozzles. Therefore, the applicant is requested to either (1) include an entry in LRA Table 2.3-4 for the containment spray nozzles which identifies their pressure-boundary and spray-flow-inducing intended functions or (2) justify the exclusion of the containment spray nozzles from an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.3-D3 In LRA Table 2.3-4, which contains the AMR screening results for the containment spray system, table entries are provided for the spray pump heat exchanger tubing and shell and cover. However, there is no entry for the heat exchanger tubesheets. The staff reviewer noted that the LRA treats heat exchangers in certain systems (e.g., residual heat removal, safety injection, chemical and volume control, spent fuel pool cooling, and various sampling systems) in a similar manner. For other systems (e.g., steam generators, component cooling water, feedwater, and diesel generator), however, tubesheets are included in the AMR screening results table. The staff believes that heat exchanger tubesheets provide a pressure boundary which may be necessary to perform intended functions for license renewal, such as ensuring the transfer of adequate heat across heat exchanger tubes, ensuring adequate system flow, and ensuring the containment of potentially radioactive fluids. It is not clear to the staff what criteria the applicant used in determining that it was not required to include heat exchanger tubesheets in the AMR screening results for certain systems, including the containment spray system. Therefore, the applicant is requested to explain the LRA's treatment of heat exchanger tubesheets, such that the staff may verify that the scoping and screening criteria used by the applicant satisfy the criteria of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.4 Containment Air Recirculation Cooling System

2.3.2.4-D1 On piping and instrumentation diagram G-190304LR Sheet 1, containment air recirculation cooling system fans HVH-9A and HVH-9B, their suction flowpath (up to the first isolation damper), and their discharge flowpath, are not highlighted as being within the scope of license renewal. These fans and their associated components appear to provide cooling to the reactor vessel, vessel supports, and/or vessel shielding. Please confirm that the intended function of the containment air recirculation cooling system fans HVH-9A and HVH-9B and their associated components does not meet the license renewal scoping criteria of 10 CFR 54.4(a).

Response: Note 1.

2.3.2.4-D2 On piping and instrumentation diagram G-190304LR Sheet 1, the abbreviation "V.D." is used (e.g., at grid location E-5) to describe a component which is highlighted as being within the scope of license renewal. However, using the flow diagram legend on piping and instrumentation diagram HBR2-7063LR Sheets 1 & 2, the staff could not conclusively identify this component. Please identify this component type and either (1) identify the component/commodity group in LRA Table 2.3-5 that generically includes this component type, (2) include an additional entry in LRA Table 2.3-5 for this component type, or (3) justify the exclusion of this component type from an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.4-D3 On piping and instrumentation diagram G-190304LR Sheet 1, the normal suction flowpath and ventilation dampers for the four containment air recirculation cooling system fans (HVH-1, -2, -3, and -4) are not highlighted as being within the scope of license renewal. However, on the basis of the following statement from UFSAR Section 6.2.2.2.2, it appears that the normal suction flowpath for these containment air recirculation cooling system fans, up to and including the normal suction dampers, should have been highlighted as being within the scope of license renewal:

> "Air operator multi-bladed dampers are installed in the air inlet to each air handling unit. These dampers and normally open butterfly valves are used to route air flow through units that are operating. They have only two positions, fully open or fully closed: *the damper operation is spring loaded to the closed position required for post-accident operation*, the butterfly valves will remain open. Their design permits only nominal air leakage when closed. [emphasis added]"

In consideration of 10 CFR 54.4(a) and the above statement from the UFSAR, please justify the exclusion from the scope of license renewal of the ductwork and ventilation dampers identified above. Also, if these items are determined to be within scope, considering 10 CFR 54.21(a)(1), please identify whether they are included in LRA Table 2.3-5 as being subject to an AMR.

Response: Note 1.

2.3.2.4-D4 On piping and instrumentation diagram G-190304LR Sheet 1, the 8 discharge lines from the containment air recirculation cooling system ring header which penetrate the shield wall each appear to be protected by a semi-circular or horseshoe-shaped component at their termination point inside the shield wall. It is not clear from the diagram whether the license renewal boundary includes or excludes this component. Please identify this component type and either (1) identify the component/commodity group in LRA Table 2.3-5 that generically includes this component type, (2) include an additional entry in LRA Table 2.3-5 for this component type, or (3) justify the exclusion of this component type from being considered within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.5 Containment Isolation System

2.3.2.5-D1 The applicant has not identified hydrogen control as an intended function for the post accident hydrogen system (i.e., by grouping it in the containment isolation system, the applicant has indicated that the only intended function of the post accident hydrogen system is containment isolation). However, UFSAR Section 6.2.5.1 states that:

> "The current licensing basis for hydrogen control is described in UFSAR Section 6.2.5.2.2, the Post Accident Hydrogen Recombiner System. The contribution of the Post Accident Containment Venting System to LOCA offsite dose give [sic] in the following UFSAR Section 6.2.5.3 are also retained for historical reference information

purposes. The current LOCA offsite dose calculation, based on recombiner operation which eliminates intentional containment venting, is presented in UFSAR Section 16.6.5.5."

This UFSAR citation, and the UFSAR descriptions it references, apparently indicate that the hydrogen recombiners are relied upon in the plant's current safety analysis to prevent the accumulation of a combustible concentration of hydrogen within the containment building. Therefore, according to the criterion of 10 CFR 54.4(b), please justify not considering the hydrogen control function of the post accident hydrogen system (specifically, the recombination of hydrogen with the hydrogen recombiners) as an intended function for license renewal.

Response: Note 1.

2.3.2.5-D2 The applicant has not included within the scope of license renewal the pressure-boundary components of the post accident hydrogen system flowpath that are associated with the hydrogen control intended function, excepting those components needed to effect containment isolation. The long-lived, passive, pressure-boundary components of this flowpath on piping and instrumentation diagram HBR2-06933LR Sheet 1 that appear to support the hydrogen control intended function include tubing, piping, valve bodies, and equipment housings for blowers, filters, and recombiners. In consideration of the scoping criteria of 10 CFR 54.4(a), please justify the exclusion of any safety-related and non-safety-related pressure-boundary components associated with the hydrogen control intended function that have not been included within the scope of license renewal. Also, if any additional components are brought within scope, please identify whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.5-D3 The applicant has not included within the scope of license renewal the components supporting the post accident hydrogen system that appear to be necessary to operate the pneumatic containment isolation valves and other pneumatic valves needed for the accomplishment of the hydrogen control intended function. The components on piping and instrumentation diagram HBR2-06933LR Sheet 1 that appear to be needed to operate valves to accomplish the hydrogen control intended function include nitrogen bottles, valves, piping, tubing, and fittings. In consideration of the scoping criteria of 10 CFR 54.4(a), please justify the exclusion of any safety-related or non-safety-related components supporting the hydrogen control intended function that have not been included within the scope of license renewal. Also, if any additional components are brought within scope, please identify whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.5-D4 The applicant has apparently not included the hydrogen analyzers and their supporting components within the scope of license renewal. However, based upon the following descriptions from Section 6.2.5 of the UFSAR, it appears that the hydrogen analyzers provide an intended hydrogen monitoring function that is necessary to support the hydrogen control function, both through ensuring that a safe concentration of hydrogen exists at the recombiner influent, and by ensuring that recombiner operation occurs as required to prevent an excessive concentration of hydrogen in containment:

> "Nitrogen can be introduced to the recombiner influent so as to dilute the process flow to maintain a hydrogen concentration of no greater than 4.0 percent by volume. Hydrogen concentration in the recombiner effluent is less than 0.1 percent. The recombiner will be operated as needed to maintain a safe limit of hydrogen concentration inside containment."

> "A containment hydrogen monitoring system is capable of measuring hydrogen concentration in the containment atmosphere continuously over the range 0 to 10 percent hydrogen when the containment is within -4.7 psig to 42 psig. Remote indication is provided in the Control Room."

In consideration of 10 CFR 54.4(b) and the above statements from the UFSAR, please justify excluding the intended function of hydrogen monitoring from the scope of license renewal.

Response: Note 1.

2.3.2.5-D5 The applicant has apparently not included within the scope of license renewal the pressure-boundary components of the post accident hydrogen system flowpath that are associated with the hydrogen monitoring intended function. Considering the scoping criteria of 10 CFR 54.4(a), please justify the exclusion from the scope of license renewal of any safety-related and non-safety-related components that support the hydrogen monitoring intended function. Also, if any additional components are brought within scope, please identify whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Response: Note 1.

2.3.2.5-D6 On piping and instrumentation diagram G-190304LR Sheet 1, for both the containment pressure relief system and containment vacuum breaker system, a debris screen is located between the containment atmosphere and the inboard containment isolation valve. Section 9.4.3.2.7 of the UFSAR, entitled "Containment Pressure and Vacuum Relief System," describes the filtration intended function of these debris screens as follows:

> "The butterfly valves are protected by debris screens, located inside containment and attached to the inboard pressure and vacuum relief valves, which will ensure that airborne debris will not interfere with their tight closure."

Considering the above UFSAR description and 10 CFR 54.4(a), please justify the exclusion from the scope of license renewal of the debris screens for the butterfly valves, as well as the piping between the screens and the valves. Additionally, if the debris screens and intervening piping are determined to be within scope, considering 10 CFR 54.21(a)(1), please identify whether they are subject to an AMR.

Response: Note 1.

2.3.3.10 Containment Purge System

2.3.3.10-D1 The applicant has not included the containment purge system within the containment isolation system, which included all plant systems having no intended function other than containment isolation. However, the applicant did not specifically identify the containment isolation intended function nor any other intended function that resulted in the containment purge system being included in the LRA. From Section 9.4.3.2.6 of the UFSAR, the staff located the following description which seems to identify two potential intended functions:

> "The containment purge valves must be operable and must close within the time limit specified in the IST program in order to limit post LOCA thyroid dose and to limit the increase in peak clad temperature due to reduction in containment internal pressure."

So that the NRC staff may verify that the applicant has properly applied the license renewal scoping and screening criteria in 10 CFR Part 54, please identify the intended functions, in accordance with 10 CFR 54.4(b), of the containment purge system.

Response: Note 1.

2.3.3.10-D2 On piping and instrumentation diagram G-190304LR Sheet 1, a debris screen is located between the containment atmosphere and the inboard containment isolation valves on the containment purge inlet and containment purge exhaust lines. Section 9.4.3.2.6 of the UFSAR, entitled "Containment Purge System," describes the filtration intended function of these debris screens as follows:

> "The containment isolation butterfly valves are protected by debris screens located inside containment in the purge . . . ductwork, which will ensure that the airborne debris will not prevent their tight closure."

Considering the above UFSAR description and 10 CFR 54.4(a), please justify the exclusion from the scope of license renewal of the debris screens for the butterfly valves, as well as the ductwork between the screens and the valves. Additionally, if the debris screens and intervening ductwork are determined to be within scope, considering 10 CFR 54.21(a)(1), please identify whether they are subject to an AMR

Response: Note 1.

2.3.3.1 Sampling System

2.3.3.1-D1 Traps T-56A, B and C are shown on the Containment Vapor and Pressure Sampling System flow diagram (HBR2-6490LR) within the scope of components that require an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following design basis events to provide samples and containment pressure. However, these traps are not listed in Table 2.3-7 as components requiring an AMR. Identify where the LRA addresses the AMR for these components, or provide a justification for excluding these Traps from an AMR.

Response: Note 1.

2.3.3.1-D2 The Sampling System flow diagram 5379-353LR Sheet 1 does not show the following safety related piping as within the scope of primary sampling system components that require an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following the design basis events to provide primary system samples. Identify where the LRA addresses the AMR for these components, or provide a justification for excluding these components from an AMR.

The piping not shown within the scope of AMR is (a) between valve PS-951 and P-29, (b) between valve PS-953 and P-30, (c) between valves PS-955A/B and P-31, (d) between PS-975 and PS-977 and PS-976 (e) between PS-974B and PS-988 and (f) between PS-969B and PS-985.

Response: Note 1.

2.3.3.2 Service Water System

2.3.3.2-D1 The following components are shown on the Service Water System flow diagram G-190199LR Sheets 4, 5, 6, 9 and 10 as within the scope of service water components that require an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following the design basis events to provide cooling (ultimate heat sink). However, these are not listed in Table 2.3-8 as components requiring an AMR, nor is it identified where they are addressed. Identify where the LRA addresses the AMR for these components, indicate LR boundaries, or provide a justification for excluding these components from an AMR.

The components not listed in Table 2.3-8 are Containment Air Recirculating Units (HVH-1, 2, 3, and 4), Safety Injection Pumps A,B,C and Air Recirculating Cooling Units (HVH-6A and 6B), Diesel Generator Air Coolers (A and B), Lube Oil Coolers (A and B) and Water Jacket Heat Exchanger (A and B), Auxiliary Feed Water Pumps and Oil Coolers (A and B), Components Cooling Heat Exchanger A and B, Air Recirculating Units (HVH-7A and 7B), Equipment Room Water Coolers (WCCU-1A and 1B), RHR Air Recirculating Cooling Units (HVH-8A and 8B), and Steam Driven AFW Pump Oil Coolers.

Response: Note 1.

2.3.3.2-D2 The Service Water System flow diagram G-190199LR Sheet 3 does not show the following safety related components as within the scope of service water components that require an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following the design basis events to provide cooling (ultimate heat sink). Identify where the LRA addresses the AMR for these components, indicate LR boundaries, or provide a justification for excluding these components from an AMR.

The components not shown within the scope of AMR are penetrations Feedwater S-43, S-44 and S-45, RC Sample S-22, SG Blowdowns S-26, S-30 and S-24, Letdown Line S-27, RH

Removal S-15 RC Pump Seal Water S-19, and FI 1975A, B and C, FI 1979, FI 1978A, B and C, FI 1977, FI 1976 and FI 1980, and the connecting piping.

Response: Note 1.

2.3.3.3 Component Cooling Water System

2.3.3.3-D1 Table 2.3-9 of the Component Cooling Water System list the Heat Exchangers whose tubes and shell are within the scope of components requiring an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following the design basis events to provide cooling to essential components. However, it does not list the tube sheets of these heat exchangers (except the component cooling water heat exchangers) requiring an AMR. Identify where the LRA addresses the AMR for these heat exchangers tube sheet, or provide a justification for excluding these tube sheets from an AMR.

Response: Note 1.

2.3.3.3-D2 The following components are shown on the Component Cooling Water System flow diagram 5379-376LR Sheets 1, 2, 3, and 4 as within the scope of components that require an AMR because they provide a pressure-retaining function. These safety-related components are relied to remain functional during and following the design basis events to provide cooling to essential components. However, these are not listed in Table 2.3-9 as components requiring an AMR, nor is identified where they are addressed. Identify where the LRA addresses the AMR for these components, or provide a justification for excluding these components from an AMR.

The components shown but not listed in Table 2.3-9 are Charging pumps Heat Exchangers, Reactor Coolant Heat exchanger, Residual Heat Removal Heat Exchangers, Seal Water Heat Exchanger, Reactor Coolant Pumps, Excess letdown Heat Exchanger, Residual Heat Removal Pump Coolers, Containment Spray Pump Coolers, and High Head Safety Injection Pump Coolers.

Response: Note 1.

2.3.3.5 Instrument Air System

2.3.3.5-D1 Accumulators are shown on the Instrument Air System flow diagram G-190200LRSheet 9 as within the scope of the components requiring an AMR because they provide a pressure retaining boundary. These safety-related components are relied to remain functional during and following the design basis events to provide back-up source of air to essential components. However, these are not listed in Table 2.3-11 as components requiring an AMR, nor is it identified where they are addressed. Identify where the LRA addresses the AMR for these components, or provide a justification for excluding these components from an AMR.

Response: Note 1.

2.3.3.6 Nitrogen Supply/Blanketing System

2.3.3.6-D1 Steam Dump Nitrogen Accumulators and connecting piping are shown on the Nitrogen Supply System Flow Diagram HBR2-8606LR Sheet 2 as within the scope of the components requiring an AMR as they provide a pressure retaining boundary. However, no safety-related boundary is shown on the flow diagram for the connecting piping. Identify the safety- related piping boundary on the flow diagram or provide justification for excluding the remaining portion of the connecting piping that is not included.

Response: Note 1.

2.3.3.6-D2 Pressurizer Nitrogen Accumulator Tank is listed on Table 2.3-12 as within the scope of component requiring an AMR because it provides a pressure retaining boundary. This safety-related component is relied to remain functional during and following the design basis events to provide back-up source of nitrogen to essential components. However, it is not shown on the Nitrogen Supply/Blanketing System flow diagram HBR2-08606LR Sheet 2 referenced in the above system for LRA. Identify, the flow diagram where it is shown within the scope of component requiring an AMR.

Response: Note 1.

2.3.3.8 Primary And Demineralized Water System

2.3.3.8-D1 Section 10.4.8 of the H. B. Robinson Unit 2 Updated Final Safety Analysis Report (HBR 2 UFSAR) states:

In the event of a failure of Lake Robinson Dam, shutdown would be accomplished in an orderly manner using the condensate storage tank. When the condensate storage tank reaches a low level limit, auxiliary feedwater pump suction would be changed to the deepwell pump discharge. This source would provide the required feedwater indefinitely or until such time that some other source of feedwater can be established. It is assumed that emergency power is not required for this accident.

Section 9.2.3 of the HBR 2 UFSAR describes that three parallel deepwell pumps are part of the primary and demineralized water system. Section 2.3.3.8 of the LRA states that the primary and demineralized water system is in scope because it contains:

1. SCs that are safety-related and are relied upon to remain functional during design basis events

2. SCs which are non-safety related whose failure could prevent satisfactory accomplishment of the safety related functions

3. SCs that are relied in during postulated fires and station blackout events

Table 2.3-14 of the LRA identifies valves, piping, and fittings of the primary and demineralized water system necessary to provide a pressure retaining boundary so that sufficient flow at adequate pressure is delivered as components subject to an aging management review.

However, the associated LR flow diagram, G-190202LR, Sheet 3, indicates that only the safety-related section of piping from the auxiliary feedwater pump suction to and including valve DW-21 is within LR scope. Please clarify whether the non-safety-related piping, valve bodies, and pump casings necessary to provide a pressure retaining boundary from the deepwell pumps to valve DW-21 are included within the scope of license renewal and subject to an AMR or justify their exclusion.

Response: Note 1.

2.3.3.8-D2 Section 9.2.2.3.1 of the HBR 2 UFSAR states the following with regard to leakage from component cooling water system heat exchangers:

During normal operation, the leaking exchanger could be left in service with leakage up to the capacity of the makeup line to the system from the primary water treatment plant. By manual transfer, emergency power is available for makeup pump operation.

Section 9.2.2.3.1 of the HBR 2 UFSAR also states:

The severance of a cooling line serving an individual reactor coolant pump cooler would result in substantial leakage of component cooling water. However, the piping is small as compared to piping located in the missile protected area of the containment. Therefore, the water stored in the surge tank after a low level alarm, together with makeup flow, provides ample time for the closure of the valves external to the containment to isolate the leak before cooling is lost to essential components in the component cooling loop.

Section 9.2.3 of the HBR 2 UFSAR describes that the primary makeup water tank provides normal makeup to the component cooling water system. These statements indicate that the current licensing basis for H. B. Robinson Unit 2 credits the non-safety related supply of makeup water from the primary and demineralized water system to maintain the safety-related component cooling water system operable during anticipated operational occurrences and following design basis accidents. Section 2.3.3.8 of the LRA states that the primary and demineralized water system is in scope because it contains:

1. SCs that are safety-related and are relied upon to remain functional during design basis events

2. SCs which are non-safety related whose failure could prevent satisfactory accomplishment of the safety related functions

3. SCs that are relied in during postulated fires and station blackout events

Table 2.3-14 of the LRA identifies valves, piping, and fittings of the primary and demineralized water system necessary to provide a pressure retaining boundary so that sufficient flow at adequate pressure is delivered as components subject to an aging management review. However, the primary and demineralized water system LR flow diagram G-190202LR, Sheet 3, and component cooling water system LR flow diagram, 5379-376, Sheet 1, indicate that only the safety-related section of piping from valves CC-B32 and CC-711 to the component cooling surge tank header is within LR scope. Please clarify whether the non-safety-related piping, valve bodies, and pump casings necessary to provide a pressure retaining boundary so that sufficient flow at adequate pressure is delivered by the primary makeup water system to the component cooling surge tank are included within the scope of license renewal and subject to an AMR or justify their exclusion.

Response: Note 1.

2.3.3.9 Spent Fuel Pool Cooling System

2.3.3.9-D1 Because spent fuel pools have design features that prevent a loss of coolant inventory, a large heat capacity, reliable cooling systems, and diverse sources of makeup water, a significant loss of coolant inventory is not sufficiently probable to be included as a design basis accident. Nevertheless, spent fuel pools contain sufficient energy and radioactive material that a substantial loss of coolant inventory could result in potential offsite exposures comparable to those referred to in 10CFR100.11. Therefore, in accordance with 10CFR54.4, structures and systems relied on to remain functional during and following design basis events to maintain an adequate coolant inventory within the spent fuel pool are within the scope of license renewal. These structures and systems perform the following functions: maintain the pool pressure boundary, remove heat, and provide water to makeup for evaporative and leakage losses.

Section 9.1.3.3.1 of the HBR 2 UFSAR states the following with regard to spent fuel pool heat removal:

The SFP temperature and SFP level indicators in the SFP building and the SFP temperature alarm and SFP level alarm in the control room warn the operator of the loss of cooling or inventory. With no heat removal, the time for SFP temperature to rise from 150°F to boiling for a full core discharge which fills the SFP to capacity is approximately 6.8 hours. The warning provided by the instrumentation alarm set points, along with this slow heatup rate, would allow sufficient time to restore adequate cooling. Redundant SFP cooling pumps, along with procedurally established alternate means to supply heat sink water to the SFP heat exchanger, ensure that cooling capability for the SFP can be restored quickly.

Section 9.1.3.3.2 of the HBR 2 UFSAR also states:

The makeup water requirement due to boiling following a complete loss of cooling after a full core offload would be less than 42 gpm. The SFP large level makeup water source is the refueling water storage tank via the refueling water purification pump. This path has a capacity of 100 gpm which is more than adequate to replace the water lost.

The license renewal boundary diagram for the spent fuel pool cooling system, Drawing 5379-1485LR, Sheet 1, indicates that the spent fuel pool cooling loop is within the "Q" list and ISI Class 3 boundaries, which are typically associated with safety related sections of systems. Based on the above information, the staff concludes that the spent fuel pool cooling loop and, at a minimum, piping, valve bodies, and pump casings necessary to deliver makeup water from the refueling water storage tank are within the scope of license renewal and subject to an AMR. However, the license renewal boundary diagram indicates the majority of the cooling loop is outside of the license renewal boundary, and Section 2.3.3.9 of the LRA states that the heat removal function is not an intended function for license renewal. The LRA does not include justification for this determination.

Please add piping, valve bodies, pump casings, and other fittings necessary to support the heat removal function of the spent fuel pool cooling system and provide makeup water addition from the refueling water storage tank to the spent fuel pool to components within the identified scope of license renewal that are subject to an AMR, or justify their exclusion.

Response: Note 1.

2.3.3.11 Rod Drive Cooling System

2.3.3.11-D1 Ventilation damper housings are not highlighted on ventilation flow diagrams or identified in the license renewal application (LRA) as within scope of license renewal. While ventilation component such as fan housings and cooling coils are highlighted as within the scope of license renewal, ventilation damper housings are not highlighted on the application referenced ventilation flow diagrams. Examples of ventilation damper housings not highlighted on system flow diagrams include the following:

1. Rod drive cooling system flow diagram G-190304LR, sheet one of 4 (E3, D3, C3, B4, B5, D5, E5).

2. HVAC auxiliary building system flow diagram G-190304LR, sheet two (B4, D4, F4, G4) and sheet three (B6, D7, E1, F1, F8, G6, G7).

3. HVAC control room area flow diagram G-190304L, sheet four (C6, D4, E6, E7, F3, F5, F7)

4. HVAC fuel handling building flow diagram G-190304LR, sheet one of 4 (F3, F4, G5)

State whether these components are within the scope of license renewal and subject to an aging management review (AMR). If so, provide the relevant information about the components in order to provide the staff with the ability to coordinate between the component/commodity tables and the flow diagram drawings, and complete the aging management review tables of the LRA. If the components are not in scope or subject to an AMR, provide justification for their exclusion.

Response: Note 1.

2.3.3.11-D2 The following five passive components associated with ventilation system ductwork are not identified as within the scope of license renewal or subject to an aging management program:

5. Ductwork turning vanes

6. Ventilation system elastomer seals

7. A ventilation equipment vibration isolator flexible connections

8. Ductwork test connections

9. Ductwork access doors

State whether you agree if these components are within the scope of license renewal and subject to an AMR. If they are, provide the information necessary to complete the aging management review result tables. If these components are not in scope and subject to an AMR, provide justification for their exclusion.

Response: Note 1.

2.3.3.11-D3 Clarify whether structural sealants used to maintain the power block building pressure boundary envelope (i.e., main control room, auxiliary building, fuel handling building, containment) at design pressure with respect to the adjacent areas are included in the scope of license renewal and subject to an aging management review. Provide information relating to structural sealants use as referenced in Table 2.1-3 on page 2.1-15 of NUREG-1800 (Standard Review Plan-License Renewal). The Standard Review Plan states that an applicant's structural aging management program is expected to address structural sealants with respect to an AMR program. If structural sealants are not in the scope of license renewal and subject to an AMR, provide justification for their exclusion.

Response: Note 1.

2.3.3.13 HVAC Control Area

2.3.3.13-D1 Ductwork in the HVAC control room area system is identified on ventilation system flow diagrams referenced in the LRA as within the scope of license renewal. Ductwork performs the intended function of a pressure boundary. However, it is not included in the aging management review results Table 2.3-19 of the LRA. State whether the HVAC control room area system ductwork is subject to an AMR and provide the relevant information about this component to enable the staff to complete its review of the aging management review results table in the LRA. If ductwork is not subject to an AMR, provide justification for its exclusion.

Response: Note 1.

2.3.3.13-D2 The safe shutdown controls are identified in sections 9.4.2.2.1 and 9.4.2.3 of the UFSAR. The Robinson UFSAR states that in case of fire within the control room fire zone, the control room may be evacuated and the plant shutdown from the safe shutdown controls provided in other areas of the plant. The ventilation systems used to support use of the safe shutdown controls have not been included as part of the scoping and screening process. State whether the ventilation systems used to support the safe shutdown controls are within the scope license renewal and subject to an AMR in accordance with 10CFR54.4(a)(1) and (a)(2). If so, provide the relevant information about the components to enable the staff to complete its review of the aging management review result tables in the LRA. If the ventilation systems used to support the safe shutdown controls are not in the scope of license renewal and subject to an AMR, provide justification for their exclusion.

Response: Note 1.

2.3.3.14 HVAC Fuel Handling Building

2.3.3.14-D1 The fuel handling building HVAC system scoping flow diagram (G-190304) shows
that fans HVE-14, HVE-15, and HVE-21 and their associated ductwork, fan housings, filters, and components are excluded from the scope of license renewal. State whether these identified fans and their associated components are subject to an AMR and provide the relevant information to enable the staff to complete the license renewal review process. If these fans and associated components are not subject to an AMR, provide justification for their exclusion.

Response: Note 1.

2.3.3.15 Fire Protection System

2.3.3.15-D1 Fire hose is subject to aging, yet the staff could not identify that fire hose was included in the scoping of the LRA. Fire hose is not included in Table 2.3-21 or otherwise in Section 2.3.3.15. Table 2.4-1, discusses fire hose stations, but aging of the hose is not addressed. Table 3.3-2, discusses flexible hoses, but fire hose is exposed to a water environment and the fire water system is not discussed in the component commodity column. Include fire hose with scope and perform an AMR or provide a technical basis for excluding fire hose from scope.

Response: Note 1.

2.3.3.15-D2 On drawing HBR2-8255LR, Sheet 1, the license renewal boundary stops at FP-5, normally closed valve between the Unit 1 and Unit 2 fire water system. The UFSAR, Section 9.5.1.4.2.4 states Unit 1 fire water is available for Unit 2. The UFSAR also references the February 28, 1978 SER, which discusses the reason that the Unit 1 fire water system may be needed. Include the Unit 1 fire water system in scope of the LRA and perform an AMR or provide the technical basis for excluding this system from scope.

Response: Note 1.

2.3.3.15-D3 UFSAR Chapter 9.5.1A, Section 3.7.1.6 discusses the deluge water spray system provided for the hydrogen seal oil unit. UFSAR Section 3.7.2.6 discusses the deluge water spray system provided for the lube oil storage tank. The UFSAR includes discussions in sections 3.7.1.3 and 3.7.2.3 that dedicated shutdown cables are routed outside the turbine building area. Also, the turbine driven auxiliary feedwater pump may be affected in a turbine building fire. The February 28, 1978, SER, Section 5.23, discusses the deluge water spray systems in these areas, "The deluge systems are adequate to control fires in this area". An unmitigated fire in this area may affect the safe shutdown cables described above. Drawing HBR2-8255LR, Sheet 2, indicates that these water suppression systems are not within the license renewal boundary. Either include these deluge water spray systems within the scope of the LRA and perform an AMR or provide the technical basis for their exclusion from scope.

Response: Note 1.

<u>2.3.3.15-D4</u> An exemption dated November 25, 1983, discusses the acceptance of separation between RHR pumps in the RHR pit. The acceptance was based, in part, on the fact that there is a 22 foot high concrete wall between the pumps. The UFSAR Chapter 9.5.1A, Section 3.11, discusses separation as a feature that helps to ensure that one RHR pump will not be available in the event that the other pump is damaged by fire. The staff could not identify where in the application this barrier was identified. Verify that this barrier is included in the application and if not include this barrier within scope and perform AMR or provide technical basis for it's exclusion.

Response: Note 1.

<u>2.3.3.15-D5</u> On drawings HBR2-8255LR, sheets as indicated below, the license renewal boundaries are indicated at an open isolation valve just prior to the closed valve. Ensure that a closed valve is the license renewal boundary and is included within scope with an AMR or provide technical basis for having a license renewal boundary at an open valve.

Sheet	Open Valve	Closed Valve	Sheet	Open Valve	Closed Valve
2	FP-61	FP-55	2, 5	FP-54	FP-292
2, 5	FP-56	FP-293	2, 5	FP-58	FP-295
2	FP-71	FP-21	2, 5	FP-90	FP-411
6	FP-585	Unknown	6	FP-750	Unknown
6	FP-449	Unknown	6	FP-518	Unknown
6	FP-575	Unknown	6	FP-735	FP-731
6	FP-590	Unknown	6	FP-588	Unknown
6	FP-565	Unknown	6	FP-468	Unknown
6	FP-806	Unknown	6	FP-793	Unknown

Response: Note 1.

<u>2.3.3.15-D6</u> UFSAR Sections 3.1.5.5.6, 3.1.5.6.6, reference that the Halon 1301 systems incorporate specially designed cylinder assemblies. These cylinder assemblies are not included in Table 2.3-21. Include these tanks within scope and perform AMR or provide the technical basis for its exclusion from scope.

Response: Note 1.

<u>2.3.3.15-D7</u> UFSAR Sections 3.1.1.6, 3.1.2.6, 3.4.6, 3.5.6, reference the carbon dioxide (CO_2) systems that include many high pressure CO_2 cylinders. These cylinders are not included in Table 2.3-21. Either include these cylinders in Table 2.3-21 of the LRA and identify which section of the AMR handles aging for these items, or provide the basis for excluding theses items from scope. Also, it is common for CO_2 systems to have nitrogen pilot tanks, verify that if nitrogen pilot tanks are used that they are included in scope and are subjected to an AMR.

Response: Note 1.

2.3.3.15-D8 The UFSAR Sections 3.1.1 and 3.1.2 for the diesel generator CO_2 systems and in Section 3.7.1.5 and 3.7.2.5 for hazards in the turbine building reference the use of heat actuated devices (HAD's) for actuation of the CO_2 system. HAD's typically utilize passive tubing, this tubing could not be identified in the LRA. The tubing is often similar to the tubing of the instrument air system (see 2.3.3.5). The LRA section 2.3.3.15 states that the fire detection and actuation systems are screened with Electrical and I&C, but these devices could not be found in that section. Include this tubing in scope and perform AMR or provide the technical basis for its exclusion from scope.

Response: Note 1.

2.3.3.15-D9 The applicant uses vertical shaft fire pumps. NFPA 20, 1973 edition, states, in section 4-3.4.1, "A cast or heavy fabricated type of nonferrous cone or basket type strainer shall be attached to the suction manifold of the pump". Drawing HBR2-8255LR, Sheet 1 of 6, does not provide enough detail to determine if strainers are installed with the fire pumps. Verify if strainers are installed and if so include the strainers within scope and perform an AMR. If strainers are not installed provide, 1) verify that code of record for Robinson for installation of the fire pumps does not require strainers, and 2) the technical basis for their exclusion from scope.

Response: Note 1.

2.3.3.15-D10 Flame retardant coatings are discussed in the UFSAR Appendix 9.5.1B, Section D.1.a for areas where redundant safety related equipment is located, Sections D.2.c, D.3.c related to engineering safeguards cables, Section D.3.e relating to auxiliary building applications, Section D.3.f relating to coating of PVC jacketed cables, and cable coating are also discussed as used in the control room, cable spreading room, emergency switchgear room. Appendix 9.5.1B is described as the fire protection program per Appendix A to BTP 9.5-1. The February 28, 1978 SER, Section 4.8, states that PVC insulated cables in critical areas will be coated with a flame retardant coating and that silicone rubber insulated cables inside containment areas will be coated with a flame retardant coating. The LRA, Section 4.4.1.43 indicates that PVC cables are still relied upon at the plant. 10 CFR 50.48, Section (b)(1)(i) references Appendix A to BTP 9.5-1 SERs for plant's of this vintage. Flame retardant cable coatings could not be identified in the LRA. Include fire retardant cable coatings within scope of license renewal and perform an AMR or provide the technical basis for its exclusion from scope.

Response: Note 1.

2.3.3.15-D11 UFSAR Section 3.1.2.2, Fire Barrier Description for the Diesel Generator "A" discusses 3-hour insulation that has been applied to the "B" diesel generator service water line. The February 28, 1978, SER, Section 5.1.6(1) states that the applicant proposed to install the above insulation in addition to 3-hour rated insulation on the fuel oil makeup line to the "A" diesel generator which is located in the "B" diesel generator room. No discussion of these 3-hour fire barrier materials were identified in the LRA. Include these fire barrier materials within scope of the LRA and perform an AMR or provide the technical basis for their exclusion from scope. The staff is aware that Table 2.4-2 discusses fire barrier assemblies, but the intended function as stated is to confine or retard a fire from spreading to or from adjacent areas of the plant, the barriers discussed above are not installed for this function.

Response: Note 1.

3.3.2-D1 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.

Response: Note 1.

3.3.2-D2 Table 2.3-21, fire hydrants, cites 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 any of these systems and are typically cast iron and not carbon steel. Provide the basis for citing Table 3.3-1 item 5.

Response: Note 1.

2.3.4.4 Extraction Steam System

2.3.4.4-D1 In drawing, G-190196LR Sheet 1, please identify the extraction steam system evaluation boundaries to ensure that all the long-lived components with a passive function are included for an AMR.

Response: Note 1.

2.3.4.4-D2 The extraction steam system provides turbine overspeed protection by utilizing valves to stop the flow of reheat steam to the low pressures turbine, discuss why these valves are not identified/included in a AMR table.

Response: Note 1.

2.3.4.4-D3. The applicant states that the extraction steam system was included in the scope of license renewal. However, following screening of the system, the applicant concludes that none of the system components perform an intended function without moving parts or without a change in configuration. Therefore, none of the components in the extraction steam system boundaries is subjected to an aging management review.

The staff believes that the system components, such as piping, valves etc., are long-lived components with a passive function, and therefore are subject to an AMR. Please provide a component/commodity groups table to identify these component and their intended functions. If a component is not subject to an AMR, please provide detailed justifications for its exclusion.

Response: Note 1.

<u>2.3.4.4-D4</u>. In Section 2.3.4.4, the applicant states that the extraction steam system was included in the scope of license renewal, however, in Item 6 of Table 3.4-1, the applicant states "...... turbine and extraction steam systems are not in scope for license renewal." Please clarify this discrepancy.

Response: Note 1.

<u>2.3.4.7 Steam Cycle Sampling</u>

<u>2.3.4.7-D1</u> In Section 2.3.4.7, the applicant states that the steam cycle sampling system was included in the scope of license renewal. Also, the applicant states that the only components with an intended function in the steam cycle sampling system are sample heat exchangers.

The staff believes that the system components, such as piping, valves etc., are long-lived components with a passive function, and therefore are subject to an AMR. Please provide a component/commodity groups table to identify these component and their intended functions. If a component is not subject to an AMR, please provide detailed justifications for its exclusion.

In addition, in the drawing, "HRB2-09006LR Sheet 2," please identify the steam cycle sampling system evaluation boundaries to ensure that all the long-lived components with a passive function are included for an AMR.

Response: Note 1.

<u>2.3.4.9 Auxiliary Feedwater System</u>

<u>2.3.4.9-D1</u> Robinson LRA, Drawing G-190202-LR, Sheet 3, depicts the supply from the deep-well pumps to the auxiliary feedwater pumps as not within the scope of license renewal. As noted in UFSAR section 10.4.8, this is the source of water credited in the event of a failure of the Lake Robinson Dam. Additionally the UFSAR notes that makeup from these pumps is required after 2 hours at hot shutdown assuming the minimum volume of water in the condensate storage tank. Please explain, why isn't this alternate source within the scope of license renewal as part of the noted design-basis events?

Response: Note 1.

<u>2.3.4.9-D2</u> Robinson LRA, Drawing G-190197-LR, Sheet 4, depicting the auxiliary feedwater pump steam turbine, does not appear to include the turbine steam exhaust line. Please address whether this line is within scope of license renewal regarding whether its failure could challenge safety related equipment.

Response: This RAI is eliminated , because continuation drawing shows that auxiliary feedwater pump steam turbine exhaust line is in the scope of license renewal.

<u>2.3.4.9-D3</u> Robinson LRA, Drawing G-190197-LR, Sheet 4, depicts a restricting orifice 1402, which appears to be the cavitating venturi in the steam turbine auxiliary feedwater pump discharge pipe described in UFSAR section 10.4.8.2. This venturi limits flow in the event of low steam generator pressure in the event of a failed discharge flow control valve. The AMR tables do not clearly describe this venturi. Please identify where the venturi is specifically addressed and whether there are any unique AMR associated with such a passive device.

Response: Note 1.

<u>2.3.4.10 Condensate System</u>

<u>2.3.4.10-D1</u> In the Robinson LRA, Drawing G-190197-LR, Sheet 1, please explain why isn't the 6 inch vent pipe on the top of the condensate storage tank highlighted as within the scope of license renewal. Is there an alternate means to provide vacuum protection for this tank?

Response: Note 1.

<u>2.3.4.10-D2</u> In the Robinson LRA, Drawing G-190197-LR, Sheet 1, the class breaks for a number of the pipes connected to the condensate storage tank appear to be directly at the tank itself and a number of pipes have such a break located immediately downstream of the first valve away from the tank. The license renewal boundary highlighting conform with these class breaks.

Please explain what is the basis for some piping being in-scope of license renewal up to the first valve and some terminating at the tank (e.g., pipe to valve C-436, pipe to valve C-438, piping from Demin water supply depicted with a dashed line, and pipe (tank overflow line?) labeled 12-C-152N-55); given the pressure boundary intended function for the tank?

Response: Note 1.

<u>2.3.4.10-D3</u> In the Robinson LRA, Drawing G-190197-LR, Sheet 1, depicts a diaphragm within the Condensate Storage Tank. Although the diaphragm is discussed in Table 3.4-2, please explain why isn't it listed in Table 2.3-30 as a component requiring an AMR?

Response: Note 1.

<u>2.4.1 Containment</u>

<u>2.4.1 -D1</u> Section 2.4.1.1.1 of the LRA states that waterproofing membrane was installed on the reactor sump structure to inhibit the intrusion of groundwater and it is considered to be a sub-component of concrete walls and slabs. Table 2.4.1 of the LRA lists two types of concrete components requiring AMR. One is external reinforced concrete components (missile shield slabs, walls, roof slabs) and the other is reinforced concrete (cylinder wall, dome, basement). None of the components lists "inhibit the intrusion of groundwater" under the column of intended function. The staff believes that waterproofing membrane is a long-lived component with a passive function, and therefore is subject to an AMR in accordance with 10CFR54.21. Explain whether the waterproofing membrane is in scope and subject to an AMR for license renewal. If it is in scope, indicate the location (under which component/commodity) and Table number where it is listed. Provide justification if it should not be in scope. This RAI is also applicable to the waterproofing membrane in the Reactor Auxiliary Building.

Response: This RAI is withdrawn, because the information is available within the LRA Tables 2.4.1 and 2.4.2..

2.4.1-D2 Table 2.4.1-1 of the LRA lists containment equipment hatch and personnel air lock as components of the containment that are subject to an AMR. However, the applicant did not identify certain operable parts of the air lock that may require an AMR. The staff believes that many such components are long-lived with a passive function, and therefore are subject to an AMR in accordance with 10CFR54.21. Explain whether the air lock door interlock system, equalizing valves, door seals, and operation mechanism (such as gears, latches, hinges, etc.) are in scope and subject to an AMR for license renewal. If they are in scope, indicate the location (under which component/commodity) and Table number where they are listed. Provide justification if they should not be in scope.

Response: This RAI is withdrawn, because the information is available within the LRA Table 2.4-1.

2.4.2 Other Structures

2.4.2-D1 Section 3.2.1.2 of the Updated Final Safety Analysis Report (UFSAR) states that the foundation and anchor system of the S/G Drain (flash) Tank are designed to seismic Class I. Explain whether the foundation and anchor system of the S/G Drain (flash) Tank are in scope and subject to an AMR for license renewal. If they are in scope, indicate the location (under which component/commodity) and Table number where they are listed. Provide justification if they should not be in scope.

Response: Note 1.

2.4.2-D2 Section 3.2.1.2 of the Updated Final Safety Analysis Report (UFSAR) states that the concrete missile shield wall and the support slab for the above-ground portions of the Service water system North Header are class I. Explain whether the concrete missile shield wall and the support slab are in scope and subject to an AMR for license renewal. If they are in scope, indicate the location (under which component/commodity) and Table number where they are listed. Provide justification if they should not be in scope.

Response: Note 1.

2.4.2-D3 Section 2.4.2.3 of the LRA states that safety related piping is routed through a Class III portion of the Turbine Building in a concrete trench. Table 2.4-4 lists reinforced concrete (beams, walls, floors, columns, etc) as components requiring AMR, but does not list concrete trench as a component requiring AMR. Clarify whether the concrete trench is in scope and subject to an AMR. If it is in scope, indicate the location (under which component/commodity) and Table number where it is listed. Provide justification if it should not be in scope.

Response: Note 1.

<u>2.4.2-D4</u> Section 2.4.2.12 of the LRA states that the Primary Water Storage Tank was determined to be outside of the intended function boundary for license renewal. However, the Robinson UFSAR lists the Primary Water Storage Tank being a Class I component. Provide justifications on your determination that the Primary Water Storage Tank should not be in scope.

Response: Note 1.

<u>2.4.2-D5</u> Table 3.2.1-2 of the Updated Safety Analysis Report (USAR) lists Refueling water Storage Tank, Accumulator Tanks, Boron Injection tank, Fuel Oil storage tank, Chemical Drain Tank, Waste Holdup tanks, Sump Tank, Gas Decay Tanks, Spent Resin Storage Tank, Reactor Coolant Drain Tank being Class I components. However, none of the tanks is listed on Table 2.2-1, License Renewal Scoping Results for Mechanical Systems or Table 2.2-2, License Renewal Scoping Results for Structures of the LRA. The staff believes that these passive long-lived Class I tanks and their foundations are within the scope of license renewal and subject to an AMR. Clarify whether these tanks and their foundations are within scope and subject to an AMR. If they are in scope, indicate the location (under which component/commodity) and Table number where they are listed. Provide justification if they should not be in scope.

Response: Note 1.

<u>2.4.2-D6</u> Table 2.4-12 of the LRA lists Concrete Tank Foundation as a component requiring AMR. This information is too general. Please provide the name of the tanks that their concrete foundations require AMR.

Response: Note 1.

<u>2.4.2-D7</u> Section 2.4.2.5 of the LRA states that components associated with Radwaste Building cranes and hoists and fire doors and fire penetrations were considered in the review, but does not state the review results. Provide the review results as to whether these components are subject to AMR and, if not, provide justifications.

Response: Note 1.

<u>2.4.2-D8</u> Section 2.4.2.6 of the LRA states that there are three traveling screens to remove small debris from the intake water, but the screens are not listed as components requiring AMR in Table 2.4-6. Provide justifications on the exclusion of the screens for AMR.

Response: Note 1.

<u>2.5.1 Electrical/I&C Components</u>

<u>2.5.1-D1</u> The screening results in Section 2.5.1 do not include any offsite power system structures or components. The license renewal rule, Section 10 CFR 54.4(a)(3), requires that, "all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission regulation for ..... station blackout (10 CFR 50.63) be included within the scope of license renewal. The station blackout rule, Section 10 CFR 50.63(a)(1), required that each light-water-cooled power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration (the coping duration) that is based upon factors that include: "(iii) The expected frequency of loss of offsite power, and (iv) The probable time needed to recover offsite power." Licensees' plant evaluations followed the guidance in NRC Regulatory Guide (RG) 1.155 and NUMARC 87-00 to determine their required plant specific coping duration. The criteria specified in RG 1.155 to calculate a plant specific coping duration were based upon the expected frequency of loss of offsite power and the probable time needed to restore offsite power, as well as the other two factors (onsite emergency ac power source redundancy and reliability) specified in 10 CFR 50.63(a)(1). In requiring that a plant's coping duration be based on the probable time needed to restore offsite power, 10 CFR 50.63(a)(1) is specifying that the offsite power system be an assumed method of recovering from an SBO event. Disregarding the offsite power system as a means of recovering from an SBO event would not meet the requirements of the rule and would result in a longer required coping duration. The function of the offsite power system with the SBO rule is, therefore, to provide a means of recovering from the SBO. This meets the criteria within license renewal 10 CFR 54.4(a)(3) as a system that performs a function that demonstrates compliance with the Commission's regulations on SBO. Based on this information the staff requires that applicable offsite power system structures and components need to be included within the scope of license renewal and subject to an AMR, or additional justification for its exclusion needs to be provided. Your response should include single line diagram showing preferred offsite power recovery path. The staff guidance on scoping of equipment relied on to meet the SBO rule for license renewal is contained in a April 1, 2002, letter to the Nuclear Institute and the Union of Concerned Scientists.

Response: Note 1.

2.5.2 Application of Screening Criterion

2.5.2-D1 In the LRA Section 2.5.2, the applicant identified electrical/I&C component commodity groups to meet the screening criteria of 10 CFR 54.21(a)(1)(i) and evaluated against the criteria of 10CFR54.21(a)(1)(ii). LRA Table 2.5-1 Electrical/I&C Component Groups did not include fuse holders. Please explain why fuse holders are not included in the list of commodity groups.

Response: Note 1.

2.5.2-D2 In the LRA Section 2.5.2, the applicant identified bus ducts to meet the screening criteria of 10 CFR 54.21(a)(1)(i) and evaluated against 10 CFR 54.21(a)(1)(ii). However, in Table 3.6-2, the applicant stated that "Based on the RNP AMR, no applicable aging effects were identified for the bus duct. Therefore, it is concluded that no aging management activities are required for the extended period of operation." Please explain why the connections (two end devices and intermediate points) will not require any aging management. These circuits may be exposed to appreciable ohmic or ambient heating during operation and may experience loosening related to the repeated cycling of connected loads or of the ambient temperature environment (refer to SAND 96-0344).

Response: Note 1.

3.0 Aging Management Review Results

3.0-D1 Several RNP AMPs were described by the applicant as being consistent with GALL, but with some deviation from GALL. These deviations are two types, exceptions and enhancement. Please provide detail definition of exception and enhancement used in the application.

Response: Note 1.

3.1 Aging Management of Reactor Vessel, internals, and Reactor Coolant System

3.1.2.1-D1 In column 5, "Discussion," of AMR Item 18 to LRA Table 3.1-1, the applicant discusses the potential for SCC/IGSCC to occur in the RV studs and stud assembly. The applicant states that stress corrosion cracking (SCC) is not an applicable effect for alloy 4140 steels (i.e., quenched and tempered low-alloy steel conforming to Specification SA 193 for Grade B7 steels) because the minimum yield strength for the materials is less than 150 ksi. Minimum yield strength is not a material property but rather an acceptance criterion in ASME Material Specification SA-193 that must be met for SA-193, Grade B7 steels used for bolting components. For these materials, SA-193 specifies 105 ksi as the minimum yield strength for SA-193, Grade B7 materials must conform to. In the staff's generic SE on WCAP-14574 for license renewal of PWR pressurizer components, dated August 7, 2000 (ADAMS Accession Number ML003738981), the staff concluded that SCC in these materials may be minimized if yield strengths for the bolts were held to less than 150 ksi or if hardness for the bolts was maintained to less that 32 on Rockwell C hardness scale. Therefore, in the generic SE, the staff stated that an applicant for license renewal may conclude SCC is not an applicable effect for SA-193, Grade B7 steels used in bolting components if the applicant would demonstrate that the yield strengths for the bolting components were controlled to less 150 ksi or if the hardness for the bolts was controlled to less than 32 on a Rockwell C hardness scale. Please confirm that intent of the discussion section for Item 18 of Table 3.1-1 of the LRA is to state that applicant has confirmed that the yield strengths for the RV bolts are within the 105-150 ksi range. If this is the intent of the discussion section, AMR Item 18 of LRA Table 3.1-1 is consistent with GALL.

Response: Note 1.

3.1.2.1-D2 The scope of AMR Item 21 of LRA Table 3.1-1 (Page 3.1-20 of the LRA) includes "steam generator components" that are susceptible to flow assisted corrosion. For recirculating steam generators (SGs), the steam generator commodity groups that are susceptible to FAC are covered by the scope of AMR Items IV.D1.1-d (pressure boundary and structural SG commodity groups), IV.D1.2-h (SG tube bundle commodity group), IV.D1.3-a (upper SG assembly and separators commodity group) in GALL Volume 2, and include the following GALL components: IV.D1.1.2, "steam nozzle and safe-end"; IV.D1.1.5, "feedwater nozzle and safe-end"; IV.D1.2.2, "SG tube support lattice bars"; and IV.D1.3.1, "feedwater inlet ring and support." Please list the exact steam generator components that are covered within the scope of AMR Item 21 of Table 3.1-1 and are susceptible to FAC, and provide your basis why the AMR for the components within the scope of AMR Item 21 is considered to be consistent with the AMR Items IV.D1.1-d (pressure boundary and structural SG commodity groups), IV.D1.2-h (SG tube bundle commodity group), and IV.D1.3-a (upper SG assembly and separators commodity group) of GALL Volume 2.

Response: Note 1.

3.1.2.1-D3 The first AMR Item of page 10 to Table 1 of GALL, Volume 1, identifies that loss of material due to wear, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading and/or stress corrosion cracking (SCC) are applicable aging effects for bolts used in the reactor coolant pressure boundary (RCPB), including valve closure bolting, manway and holding bolting and bolting in high-pressure/high-temperature systems. In the discussion section of AMR Item 22 of LRA Table 3.1-1, the applicant implies that loss of material due to wear and loss of preload due to stress relaxation are not applicable aging effects for the bolts used to secure the primary and secondary SG manways. The applicant also implies that cracking due to cyclic loading is not an applicable effect for RCPB bolting. Please provide technical basis for concluding why loss of material due to wear and loss of preload due to stress relaxation are not applicable effects for the bolts used to secure the primary and secondary SG manways and technical basis for concluding why cracking due to cyclic loading is not an applicable effect for all RCPB bolting. In addition, please confirm that cracking due to SCC is an applicable aging effect for the SG primary manway bolts.

Response: Note 1.

3.1.2.1-D4 In Item 23 of LRA Table 3.1-1, the applicant identifies that crack initiation and growth by primary stress corrosion cracking (PWSCC) is applicable to the CRDM nozzles fabricated from Alloy 600 and proposes to use the Nickel-Alloy Nozzles and Penetrations Program and the Water Chemistry Program are applicable programs for managing this effect. While Item 23 of LRA Table 3.1-1 is consistent with the corresponding AMR for CRDM nozzles in Item IV.A2.2-a of GALL-2, the applicant did not indicate whether the Robinson upper vessel head included head vent nozzle or instrumentation nozzles made from Alloy 600. Please state whether the RNP upper vessel head includes a head vent nozzle or instrumentation nozzles made from Alloy 600. If the Robinson upper vessel head does the component/commodity group column of Item 23 to LRA Table 3.1-1 must be amended to include these components.

Response: Note 1.

3.1.2.1-D5 In Item 24 of LRA Table 3.1-1, the applicant identifies that crack initiation and growth due to cyclic loading, SCC, and/or PWSCC are applicable to the RCS nozzle safe-ends, CRDM housings, and RCS components other than bolting materials or RCS components made from CASS. AMR Item IV.C2.2-f of GALL, Volume 2, provides the AMR for managing crack initiation and growth due to cyclic loading, SCC, and/or PWSCC in RCS nozzle safe-ends, including the safe-end of the hot-leg nozzle to the reactor vessel. Please provide an expanded discussion of how your AMR analysis in Item 24 of LRA Table 3.1-1 has addressed potential implications and lessons learned from the Summer hot-leg nozzle cracking, and specifically how AMR for Item 24 has resolved potential issues identified in Information Notices 2000-17, 2000-17, Supplement 1, and 2000-17, Supplement 2, (dated October 18, 2000, November 16, 2000, and February 28, 2001, respectively) as related the Summer cracking event.

Response: Note 1.

3.1.2.1-D6 In Item 26 of LRA Table 3.1-1, the applicant identifies that potential boric acid is an applicable aging effect for the external surfaces of all carbon steel components in the reactor coolant pressure boundary, and that the boric acid wastage program will be used to manage this aging effect in the RCPB components. Wastage of carbon steel and low alloy steel RCS components in PWRs is a concern if the components are exposed to potential leaks of the borated reactor coolant. The boric acid wastage event of the Davis Besse reactor vessel head, which is discussed in NRC Bulletins 2002-01 and 2002-02, is a prime example of severe wastage that has occurred in the industry as a result of a prolonged exposure to a CRDM nozzle leak of the borated reactor coolant. NRC NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants," provides a summary of other boric acid wastage events that have occurred in the U.S. nuclear power industry prior to the summer of 1990. You state that AMR in Item 26 of LRA Table 3.1-1 is consistent with GALL without the need for further evaluation. The component/commodity group column of Item 26 in LRA Table 3.1-1 does not include ASME Class 1 RCS components from low-alloy steel (including RV shells and heads made from low-alloy steel grades) among those RCS components that could be potentially exposed to leaks of the borated reactor coolant and subject to loss of material as a result of boric-acid induced wastage. The discussion column of Item 26 in LRA Table 3.1-1 does not address the implications of the Davis Besse boric-acid wastage event on the ability of the boric acid corrosion program to manage potential boric-acid-corrosion induced wastage of carbon steel and low-alloy steel components of the RCS. Please amend Item 26 in LRA Table 3.1-1 to: (1) include both carbon steel and low-alloy steel ASME Class 1 components as being among the Class 1 RCS components that could potentially be affected by loss of material as a result of boric-acid induced wastage, and (2) include how the implications and lessons learned from the Davis Besse boric-wastage event have been addressed/resolved relative to your AMR for Item 26. In addition, please indicate whether the RCS inlet, outlet and safety injection nozzles may be potentially susceptible to this aging effect and whether the scope of AMR in Item 26 to LRA Table 3.1-1 includes these components. In addition, with respect AMR Item 26 of LRA Table 3.1-1, please confirm that loss of material due to aggressive corrosive attack (i.e., due to leaks of the borated reactor coolant) is an applicable aging effect for the primary steam generator manway covers and bolts.

Response: Note 1.

3.1.2.1-D7 AMR Item 27 of LRA Table 3.1-1 (Page 3.1-24 of the LRA) provides the applicant's AMR for possible erosion in the SG secondary manways and handholds. The applicant stated that the GALL report indicates this item is applicable to once-through steam generators; therefore, it is not applicable to RNP. For the SG secondary manways and handholds in recirculating SGs (GALL component IV.D.1.1.7), the AMR for this item is specified in AMR commodity group Item D1.1-f (page IV D1-4) of the GALL Volume 2. RNP has recirculating steam generators. Please provide AMRs, including your identification of aging effects and aging management programs, if applicable, of the secondary manways and handholds. If erosion of the RNP SG secondary manways and handholds is not determined to be an applicable effect for the RNP SG secondary manways and handholds, please provide technical basis for deviating from the staff's AMR given in AMR commodity group Item D1.1-f (page IV D1-4) of the GALL Volume 2.

Response: Note 1.

3.1.2.1-D8 The applicable GALL Volume 2 AMR entries are AMR Item IV.B2.1-d for loss of preload/stress relaxation in the upper internals assembly hold down springs (GALL component IV.B2.1.7), AMR Item IV.B2.5-h for the lower support plate column bolts (GALL component IV.B2.5.5) in the lower internals assembly, and IV.B2.5-i for the clevis insert bolts (GALL component IV.B2.5.7) of the lower internals assembly. Management programs recommended by GALL these items are ISI Plan for ASME IWB, IWC and IWD components for the upper internals assembly hold down springs (GALL Item IV.B2.1-d); the ISI Plan for ASME IWB, IWC and IWD components (GALL Program XI.M1) and loose parts monitoring activities (GALL Program XI.M14) for the lower support plate column bolts; and the ISI Plan for ASME IWB, IWC and IWD components and either the loose parts monitoring activities or neutron noise monitoring activities (GALL Program XI.M15) for the clevis insert bolts. AMR in item 30 of LRA Table 3.1-1 does not list the applicable lower and upper internal assembly subcomponents that are subject to loss of preload due to stress relaxation. Please modify AMR entry 30 in LRA Table 3.1-1 to clarify which of the reactor vessel (RV) upper internal assembly components and RV lower internals assembly mechanical closure components are susceptible loss of preload due to stress relaxation and assess the consistency of your AMRs for these components against the corresponding AMRs provided in AMR Items IV.B2.1-d, IV.B2.5-h, and IV.B2.5-i of GALL, Volume 2. In addition, the applicant states that AMR for the lower internal assembly clevis insert pins is not consistent with GALL because the applicant uses a slightly different combination of AMPs to manage loss of preload in the clevis insert pins but include this commodity group in both LRA Table 3.1-1 and LRA Table 3.1-2. Please confirm the AMR entry for this commodity group is really not consistent with GALL and that therefore the applicable AMR for this commodity group is appropriately reviewed and discussed in item 15 of LRA Table 3.1-2.

Response: Note 1.

3.1.2.1-D9 Part (1) AMR Item 31 of Table 3.1-1 provides for loss of fracture toughness due to neutron irradiation embrittlement and/or thermal aging and void swelling in RV internals in the fuel zone (other than Westinghouse and B&W baffle/former bolts). The corresponding AMR Item commodity groups in GALL Volume 2 are AMR Items IV.B2.3-c, IV.B2.4-e, IV.B2.5-c, IV.B2.5-g, and IV.B2.5-n and include the following GALL components: IV.B2.3.1, "core barrel"; IV.B2.3.2, "core barrel flange"; IV.B2.3.3, "core barrel outlet nozzles"; IV.B2.3.4, "thermal shield"; IV.B2.4.1, "baffle and former plates"; IV.B2.5.1, "lower core plate"; IV.B2.5.2, "fuel alignment pins"; IV.B2.5.5, "lower support plate column bolts"; IV.B2.5.7, "clevis insert bolts"; IV.B2.5.3, "lower support forging or casting"; and IV.B2.5.4, "lower support plate columns." The applicant provided a tool (handout) for assisting the staff in identifying which of the GALL components were covered by the AMR Items in Table 3.1-1 of the LRA. For AMR Item 31, the "tool" indicated that the corresponding GALL components covered within the scope of AMR Item 31 were GALL components IV.B2.3.1, "core barrel"; IV.B2.3.2, "core barrel flange"; IV.B2.3.3, "core barrel outlet nozzles"; IV.B2.3.4, "thermal shield"; IV.B2.4.1, "baffle and former plates"; IV.B2.5.1, "lower core plate"; IV.B2.5.2, "fuel alignment pins"; IV.B2.5.5, "lower support plate column bolts"; IV.B2.5.7, "clevis insert bolts"; IV.B2.5.3, "lower support forging or casting"; and IV.B2.5.4, "lower support plate columns."

Please provide technical basis for omitting the following GALL components from the scope of AMR 31 in LRA Table 3.1-1: IV.B2.3.2, "core barrel flange"; IV.B2.3.3, "core barrel outlet nozzles"; IV.B2.3.4, "thermal shield"; and IV.B2.5.4, "lower support plate columns." If any of these components should be included within the scope of AMR Item 31 of LRA 3.1-1, please revise AMR Item accordingly to include and state which AMP will be used to manage loss of fracture toughness due to neutron irradiation embrittlement and void swelling in the components.

Part (2) Item IV.B2.5-n of GALL Volume 2 covers loss of fracture toughness due to neutron irradiation and void swelling in lower support forging/casting and in the lower support plate columns. AMR Item 31 of Table 3.1-1 does not clearly identify whether or not the lower support and lower support plate columns are fabricated from statically cast austenitic stainless steel (CASS) materials. If either of these components is fabricated from CASS, loss of fracture toughness due to thermal aging is an applicable aging effect for the components and the "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program" should be proposed to manage this effect. In order for the components to be consistent with AMR Item IV.B2.5-m of GALL Volume 2, please state whether the RV internal lower support and lower support plate columns are fabricated from CASS materials, and if so, provide a supplemental AMR for these components that is consistent with AMR Item IV.B2.5-m of GALL Volume 2.

Response: Note 1.

3.1.2.1-D10 Please confirm that this item is really not consistent with GALL and should not be included in Table 3.1-1 Item 35, and that instead the item is appropriately addressed by the aging management review stated in item 15 of Table 3.1-2 of the application. Also please confirm that Item 35 of LRA Table 3.1-1 is redundant with Item 30 of LRA Table 3.1-1.

Response: Note 1.

3.1.2.2.1 - Cumulative Fatigue Damage

3.1.2.2.1-D1 In Table 2.3.1-1, the applicant identifies that all RCS pressure boundary components may be susceptible to thermal fatigue (i.e., refer to Item 1 in Table 3.1-1 of the LRA), but only identify that some of the reactor vessel (RV) internals serving support functions are susceptible to thermal fatigue. Please provide justification why a thermal fatigue analysis (TLAA) is not needed for those RV internals listed in Table 2.3.1-1 that are not referred to as being within the scope of Item 1 in Table 3.1-1 (i.e., the AMR entry in Table 3.1-1 for RCS components subject to thermal fatigue). If any of these RV internal components are passive components that are within the scope of license renewal and susceptible to thermal fatigue during period of extended operation they should be included within the scope of Item 1 in Table 3.1-1 of the LRA and analyzed within the scope of the TLAA for thermal fatigue, as described in Section 4.3 of the LRA. Section 4.3 of the LRA should then be revised accordingly.

Response: Note 1.

3.1.2.2.2. - Loss of Material due to Pitting and Crevice Corrosion

3.1.2.2.2-D1 In regard to aging management review for the steam generator (SG) shell assembly, as provided in Item 2 of Table 3.1-1 to the RNP license renewal application (LRA), please amend the AMR in Item 2 to list the transition cone (GALL component IV.D1.1.4) as an additional component in the SG shell assembly requiring aging management, as evaluated consistent with Item IV.D1.1-c of GALL Volume 2.

Response: Note 1.

3.1.2.2.3 - Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

3.1.2.2.3-D1 Please clarify in column 5 of AMR Item 3 of LRA Table 3.1-1 that the TLAA proposed in the AMR will be performed in accordance with the following requirements:

> The evaluation criteria requirements and calculational method requirements of 10 CFR §50.61 for calculating RT_{PTS} for the RV beltline materials (i.e., materials with amassed neutron fluences in excess of 1 x 10^{17} n/cm^2) and demonstrating that they will have adequate protection against PTS events through the expiration of the extended period of operation for RNP.
>
> The requirements of 10 CFR Part 50, Appendix G, Section IV.A.2, for generating the P-T limits for the RCS through the expiration of the extended period of operation for RNP. The requirements of 10 CFR Part 50, Appendix G, Section IV.A.1, for demonstrating that the RV beltline materials will have adequate levels of USE through the expiration of the extended period of operation for RNP, including the need to perform an appropriate equivalent margins analysis should the applicant determine that the USE value for any of the RV beltline materials is below 50 ft-lbs prior to the expiration of the extended period of operation for RNP.

Response: Note 1.

3.1.2.2.4 - Crack Initiation and Growth due to Thermal and Mechanical Loading or Stress Corrosion Cracking

3.1.2.2.4-D1 The discussion section of AMR Item 6 in LRA Table 3.1-1 does not appear to credit the ASME Section XI, Subsections IWB, IWC, and IWD Program as one of the AMPs for managing crack initiation and growth in RCS small-bore piping components less than 4 NPS in size. To be consistent with AMR Item IV.C2-g in GALL Volume 2 the applicant should credit the ASME Section XI, Subsections IWB, IWC, and IWD Program as one of the three programs for managing crack initiation and growth in RCS small-bore piping components less than 4 NPS in size (i.e., in addition to the water chemistry program that meets the program attributes of GALL Program XI.M2 and a one-time inspection for the small-bore pipe that meets the program attributes describes in GALL Program XI.M32). If applicant seeks to conclude that AMR Item 6 in LRA Table 3.1-1 is consistent with AMR Item IV.C2-g in GALL Volume 2, please modify AMR in Item 6 of LRA Table 3.1-1 to add the ASME Section XI, Subsections IWB, IWC, and IWD Program as one of the three programs for managing crack initiation and growth in RCS small-bore piping components less than 4 NPS in size, or else please provide a technical basis why the ASME Section XI, Subsections IWB, IWC, and IWD Program does not need to be credited with managing cracking in these components and move the AMR in AMR Item 6 of Table 3.1-1 to Table 3.1-2 of the LRA.

Response: Note 1.

3.1.2.2.6 - Changes in Dimension due to Void Swelling

3.1.2.2.6-D1 The applicant's basis for omitting dimensional changes due to void swelling as an applicable effect for the reactor vessel (RV) internal neutron flux thimble guide tubes is that thimble tubes are partly located outside of the RV and are not expected to experience excessive irradiation at elevated temperatures. In the staff's AMR for commodity group Item IV.B2.6-b of Table IV.B2 of GALL, Volume 2, the staff identifies that void swelling is an applicable aging effect Westinghouse-designed RV internal flux thimble tubes. The applicant's AMR for evaluating dimensional changes in the RNP RV internal neutron flux thimble guide tubes is therefore not consistent with the corresponding assessment in GALL, Volume 2.

Part 1. The applicant's basis for omitting dimensional changes as an applicable aging effect for the RNP neutron flux thimble guide tubes is non consistent with AMR for commodity group Item IV.B2.6-b of Table IV.B2 of GALL, Volume 2. Since AMR for evaluating void swelling in the thimble tubes is not consistent with GALL, Volume 2, please amend Table 3.1-2 of the LRA to include a separate AMR for evaluating whether dimensional changes due to void swelling is an applicable aging effect for the RNP RV neutron flux thimble guide tubes.

Part 2. The applicant's basis for omitting void swelling as an applicable aging effect for the RNP RV neutron flux thimble guide tubes appears to rely on the basis that portions of the thimble guide tubes are located outside the RV and that these portions of the thimble guide tubes will not experience excessive irradiation at elevated temperatures. AMR commodity group Item IV.B2.6-b of Table IV.B2 of GALL, Volume 2, identified that dimensional changes due to void swelling is an applicable aging effect for the portions of Westinghouse-designed RV neutron flux thimble guide tubes that are internal to the RV because the staff considers that the portions of the thimble guide tubes within the RV cavity may experience excessive irradiation at elevated temperatures. Therefore, in regard to performing the supplemental AMR that has been requested by the staff for evaluating whether dimensional changes due to void swelling is an applicable aging effect for the RNP RV neutron flux thimble guide tubes, please provide technical basis why void swelling is not considered to be an applicable aging effect for the portions of the flux thimble tubes that could be exposed to elevated temperature and irradiation levels. If dimensional change due to void swelling is an applicable aging effect for the RNP RV neutron flux thimble guide tubes, please include this aging effect as being applicable to the neutron flux thimble guide tubes in your supplemental AMR for the thimble guide tubes and propose an applicable aging management program to manage this aging effect during the extended period of operation for RNP.

Response: Note 1.

3.1.2.2.7 - Crack Initiation and Growth due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

3.1.2.2.7-D1 For the pressurizer spray head, and steam generator instrumentation nozzles and drains, the issue is that existing programs, such as the chemistry program and/or the ASME Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program may not be sufficient to manage SCC-induced or PWSCC-induced crack initiation and growth in these components. The applicant's in AMR for these components, as given in Item 9 of LRA Table 3.1-1, is not consistent with the corresponding AMR items for these components identified in Items IV.C2.5-j and IV.D1.1-j of GALL, Volume 2, because the applicant has not proposed plant-specific inspection programs. For the pressurizer spray head and steam generator instrumentation nozzles and drains, justify the appropriateness of including AMR Item 9 among the items covered in Table 3.1-1 of the LRA, when the specific AMPs proposed to manage crack initiation and growth in these components are not the specific AMPs recommended items IV.C2.5-j and IV.D1.1-j of GALL, Volume 2, for managing these aging effects. Please include basis why the AMRs for each of these components should no be addressed as a separate entry in Table 3.1-2 of the LRA. In addition, please address the following specific inconsistencies with GALL for these components be addressed:

(1) In AMR Item IV.C2.5-j of GALL, Volume 2, the staff identifies that crack initiation and growth due to SCC or PWSCC are applicable aging effects for pressurizer spray heads made from Alloy 600 or CASS materials, and states that a plant-specific AMP is to be proposed to manage these aging effects in the pressurizer spray heads. In the discussion section of AMR Item 9 of LRA Table 3.1-1 the applicant states that the pressurizer spray head serves no function for license renewal, implying that the pressurizer spray head is not within the scope of license renewal and therefore no aging management review of the pressurizer spray head; however the pressurizer spray heads have been within the scope of license renewal for the Oconee and McGuire/Catawba LRAs. In order to be consistent with GALL Item IV.C2.5-j, if the RNP pressurizer spray head performs a license renewal function, it must be included within the scope of license renewal. In this case, the scope of AMR Item 9 of LRA Table 3.1-1 should bet amended to include the pressurizer spray head and either a one-time plant-specific inspection should be proposed to manage SCC-induced/ PWSCC-induced crack initiation and growth in the pressurizer spray head. In addition, if the pressurizer spray heads are within the scope of license renewal and made from CASS, potential loss of fracture toughness as a result of thermal aging should be addressed as a potential aging effect for the spray head, and the one-time inspection must be sufficient to detect and size cracking in the pressurizer spray prior to their exceeding the critical crack for the component. If the RNP pressurizer spray head is within the scope of license renewal please amend AMR Item 9 of LRA Table 3.1-1 to include the pressurizer spray head among the components within the scope of the commodity group for the AMR Item, and provide a revised AMR for the pressurizer spray head, including which AMPs will be credited to manage SCC-induced/ PWSCC-induced crack initiation and growth in the spray head and loss of fracture toughness if the pressurizer spray head is fabricated from CASS.

(2) In AMR Item IV.D1.1-j of GALL, Volume 2, the staff identifies that crack initiation and growth due to SCC or PWSCC are applicable aging effects for SG instrumentation nozzles and recommends that a plant-specific management program be evaluated for managing these aging effects in the SG instrumentation nozzles and drains. In Item 9 of LRA Table 3.1-1 (page

3.1-12 of the table), the applicant states that RNP steam generator instrument nozzles are not fabricated from Alloy 600, so they were not included within the scope of Item 9 to LRA Table 3.1-1. However, the applicant did not state where the AMR Item for the steam generator instrument and drain line nozzles could be found in the application, and did not provide the material of construction for the steam generator instrument and drain nozzles. Either please clarify where your aging management review for the steam generator instrument and drain nozzles may be found or, if an aging management review has not been performed for these components, please provide your AMR for the steam generator instrument and drain line nozzles, including the materials of fabrication, applicable environments, applicable aging effects, and aging management programs for the components, and include the AMR for the nozzles as a part of Table 3.1-2.

Response: Note 1.

3.1.2.2.7-D2 According to discussion section of aging management review (AMR) Item 10 to LRA Table 3.1-1, the RNP pressurizer surge nozzle and its safe-end are not fabricated from CASS and are therefore not included within the scope of the commodity group items listed for AMR Item 10. Please provide clarification which Table and AMR entry provides AMR for the RNP pressurizer surge nozzle and its safe-end. If an AMR has not been performed for the RNP pressurizer surge nozzle and its safe-end, please provide AMR for this item, including the materials of fabrication, applicable environments, applicable aging effects, and aging management programs for the components, and include the AMR for the surge nozzle and its safe-end as a part of Table 3.1-2.

Response: Note 1.

3.1.2.2.10 - Loss of Section Thickness due to Erosion

3.1.2.2.10-D1 Regarding AMR Item 14 of LRA Table 3.1-1 (Page 3.1-15 of the LRA): In the application, the applicant states that the steam generator (SG) feedwater impingement plate and support are not applicable to RNP because they are not a part of the RNP steam generators and that the RNP steam generators use feed rings with J-nozzles. In the discussion column of AMR Item 14, CP&L clarifies that the feed rings perform no license renewal intended function. For recirculating SGs, AMR Item IV.D1.3-a of GALL Volume 2 (page IV D1-12 of the report), identifies feedwater inlet ring and support (GALL component IV.D1.3.1) as components for aging management. Please clarify whether the feed ring and support need to be included in Table 3.1-1 of the RNP LRA to be consistent with the GALL report.

Response: Note 1.

3.1.2.2.11 - Crack Initiation and Growth due to PWSCC, ODSCC, or Intergranular Attack or Loss of Material due to Wastage and Pitting Corrosion or Loss of Section Thickness due to Fretting and Wear or Denting due to Corrosion of Carbon Steel Tube Support Plate

<u>3.1.2.2.11-D1</u> In Item 15 of LRA Table 3.1-1 (Page 3.1-16), the applicant provides AMR for various aging effects that are applicable to Alloy 600 steam generator tubes, repair sleeves, and plugs. The staff seeks additional information regarding AMR provided in Item 15 of LRA Table 3.1-1.

A. If sleeves and plugs have been installed in the RNP steam generators, please specify the material of construction of sleeves and plugs. Also please specify the type of plugs used in RNP (Reference: Item D1.2.3 on page IV D1-11 of the GALL report).

B. Please discuss the current and past degradation mechanisms in the RNP replacement steam generators and identify the regions where tube degradation has occurred.

C. NRC has issued the following generic communications regarding steam generator tube plugs: NRC Information Notice 89-65, "Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by Babcock and Wilcox"; NRC Information Notice 89-33, "Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs"; NRC Bulletin No. 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," and Supplements 1 and 2 to NRC Bulletin 89-01; and NRC Information Notice 94-87, "Unanticipated Crack in A Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam generator Tubes." If any of the above NRC generic communication is applicable to the tube plugs in the RNP steam generators, please discuss any corrective actions that have been taken and what would the aging management program that would be applied to manage tube plug degradation.

D. Please Clarify whether the applicant is committed to NEI 97-06. The applicant referenced NEI 97-06 but did not make a formal commitment to follow NEI 97-06.

Response: Note 1.

<u>3.1.2.2.11-D2</u> In Item 15 of LRA Table 3.1-1, the applicant stated that "...Bulletin No. 88-02 has been determined to be not applicable to Robinson Nuclear Plant (RNP) based upon the steam generator design and support plate material..." The staff needs more information regarding the applicability of RNP steam generators with respect to Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes."

Bulletin No. 88-02 reported a steam generator tube rupture event at North Anna Unit 1 which was caused by high cycle fatigue. In the bulletin, the NRC staff concluded that the following conditions could lead to a rapidly propagating fatigue failure: 1. denting at the upper support plate; 2. a fluid-elastic stability ratio approaching that for the tube that ruptured at North Anna; and 3. absence of effective anti-vibration bar support.

Please address each of the above three factors that could cause fatigue failure in RNP steam generator tubes.

Response: Note 1.

3.1.2.2.12 - Loss of Section Thickness due to Flow-accelerated Corrosion

3.1.2.2.12-D1 In LRA Table 3.1-1, Item 16 (Page 3.1-17), the applicant has stated that tube support lattice bars are not applicable to the RNP steam generators; however, it is not clear to the staff what tube support plate configuration is installed in the RNP steam generators and whether the tube support configuration would require aging management. Please clarify what type of tube support plate configuration is used in the RNP steam generator designs and whether the RNP tube support plates require aging management.

Response: Note 1.

3.1.2.4.1 - RCS Piping

3.1.2.4.1-D1 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). Please clarify which specific RCS components are included under to the scope of column 1 to AMR Item 2 in LRA Table 3.1-2.

Response: Note 1.

3.1.2.4.1-D2 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, the staff requests that the applicant provide your basis as to how implementation of RNP water chemistry control program is sufficient to provide for a level of hydrogen over-pressure that is 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. Since the applicant selected to credit the use of hydrogen water chemistry as the basis for managing pitting and crevice corrosion throughout the Class 1 RCS system, please include in your basis an assessment of how implementation of hydrogen water chemistry program is capable of maintaining an equilibrated, sufficient concentration of hydrogen in the reactor coolant throughout the system.

Response: Note 1.

3.1.2.4.1-D3 The applicant provides 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 the applicant states that this component/ commodity group consists of valves, piping, and fittings associated with piping connected to the pressurizer relief tank and that these components are subject to a dry, inert nitrogen environment on their internal surfaces. The applicant 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. However, the non-Class 1 components within this commodity group are fabricated from carbon steel, and your AMR for this commodity group only covers exposure of the components under air and gas environments but only discusses the potential for aging to occur under the dry, internal nitrogen environment. The AMR for this commodity group does not address the potential for aging to occur in the components under the external air or gas environments for the components. The staff needs clarification regarding aging of the carbon steel non-Class 1 piping, valve and fitting components within this commodity group from external air or gas environments. With respect to AMR Item 8 of Table 3.1-2 of the LRA, please state whether an AMR is performed for this commodity for the exposure of the components within this commodity group to external air or gas environments. If an AMR is performed for the surfaces of components in this commodity that are exposed to external air or gas environments, please state which Table and AMR Item that contains AMR for these components under the air or gas environments. If an AMR has not been performed, please provide AMR for the RCS piping, valve, and fitting components within this commodity group under their external air or gas environments, and identify all applicable aging effects for these components under these environments. Please state which aging management programs will be credited for these components, if aging effects are determined to be applicable for these components under external air or gas environments.

Response: Note 1.

3.1.2.4.1-D4 Column 1 of AMR Item 17 of LRA Table 3.1-2 is somewhat confusing and does not clearly indicate which RCS piping, valve, and fitting components are within the scope of the AMR. For confirmation, please clarify exactly which components are within the scope of AMR Item 17 of LRA Table 3.1-2.

Response: Note 1.

3.1.2.4.1-D5 In AMR 17 of LRA Table 3.1-2, the applicant 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. The applicant, 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, please 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.

Response: Note 1.

3.1.2.4.1-D6 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. Please 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.

Response: Note 1.

3.1.2.4.1-D7 In AMR 18 of LRA Table 3.1-2, the applicant 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 deionzied 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, please 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.

Response: Note 1.

Section 3.1.2.4.3 - Pressurizer

3.1.2.4.3-D1 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, the applicant did not in either Table 3.1-1 or 3.1-2 of the LRA provide an AMR which listed that fatigue as an applicable aging effect for the pressurizer relief tanks. Provide technical basis why the applicant 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, please 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.

3.1.2.4.3-D2 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. Please 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.

Response: Note 1.

3.1.2.4.3-D3 In AMR Item IV.C2.6-c of GALL, Volume 2, the staff states that crack initiation and growth due to stress corrosion cracking (SCC) are applicable aging effects for the internal surfaces of pressurizer relief tanks that are fabricated with carbon steel material and clad internally with austenitic stainless steel and are exposed to chemically treated borated water. The cracking phenomena discussed in AMR Item IV.C2.6-c of GALL, Volume 2, is associated with SCC-induced cracking that initiates and growth in the cladding of the pressurizer relief tanks. The pressurizer relief tank at RNP is not clad with austenitic stainless steel. Please confirm that the applicant's basis not concluding that crack initiation and growth due to SCC is not an applicable aging effect for the RNP pressurizer relief tank because the RNP pressurizer relief tank is not clad with austenitic stainless steel and because the applied loads for the tank are low.

Response: This RAI is withdrawn, because the information is available within the LRA in Item 13, Table 3.1.2.

3.1.2.4.4 - Reactor Vessel and CRDM Nozzle/Housing Components

3.1.2.4.4-D1 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 applicant AMR for the bottom head instrumentation tubes is not consistent with GALL because it 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. Please 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, or else either propose a plant-specific AMP to manage these effects in the RV bottom head instrumentation tubes or indicate that the applicant is committed to participate and implement recommended actions developed by industry-wide programs designed for determining the appropriate AMPs for managing crack initiation and growth in Westinghouse-design bottom head instrumentation tubes.

Response: Note 1.

3.1.2.4.5 - Reactor Vessel Internals

3.1.2.4.5-D1 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). The applicant 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 the applicant 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 RNP RV core support pads.

Response: Note 1.

3.1.2.4.5-D2 In AMR Item 16 of LRA Table 3.1-2, the applicant credited only the Chemistry Control Program with managing SCC in the RNP RV neutron flux thimble guide tubes. The RNP RV neutron flux thimble guide 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. Please provide technical basis why the water chemistry program alone is considered to be sufficient to manage PWSCC in the RV neutron flux thimble guide tubes without the need for confirmation using an inspection-based program that will detect for PWSCC-induced cracking in the components. Consistent with AMPs recommend in GALL commodity group AMR 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 guide tubes.

Response: Note 1.

3.1.2.4.6 - Steam Generators

3.1.2.4.6-D1 In AMR Item 3 of Table 3.1-2 (LRA Page 3.1-32), the applicant 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. Please discuss why crevice corrosion was identified rather than fretting and wear for this item.

Response: Note 1.

3.1.2.4.6-D2 In AMR Item 11 of LRA Table 3.1-2 (LRA Page 3.1-36), the applicant identified the water chemistry program as the only AMP to manage the aging effect of stress corrosion cracking of the steam generator lower head, divider plate and tubesheet cladding. However, the staff believes that the steam generator tube integrity program, boric acid corrosion program, and ISI program should also be included as the AMPs for this item. The ISI program is needed to inspect the lower head. The steam generator tube integrity program is needed to inspect the tubesheet cladding. The boric acid program is needed to assure that the exterior of the lower head would not affected by the boric acid corrosion. Please discuss why these programs were not identified.

Response: Note 1.

3.1.2.4.6-D3 The applicant 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. Please provide 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.

Response: Note 1.

3.1.2.4.6-D4 In the discussion Section of AMR Item 12 of Table 3.1-2 of the LRA, the applicant concludes that stress corrosion cracking (SCC) is not an applicable aging effect for the 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 for the materials are lower than 150 ksi or 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, please confirm that either the yield strengths (and not minimum yield strengths) for heats of material used to fabricate the SG secondary side manway and handhole bolts, as ascertained from the certified material test reports (CMTRs) for the materials, are less than 150 ksi or that the hardness levels for the bolting materials are less than 32 on a Rockwell C hardness scale, as ascertained from the CMTRs.

Response: Note 1.

3.2 - Engineered Safety Feature

3.2.1-D1 In LRA Table 3.2-1, Item 2, it 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). For carbon and low alloy steel containment isolation components, exposed to treated water, raw water, and liquid waste, GALL specifically requires, however, that a plant specific AMP be evaluated for the loss of material due to general corrosion, pitting, crevice, MIC, and bio-fouling. The staff found the applicant’s conclusion, that the containment isolation components would not be susceptible to corrosion, under the assumed environments, to be lacking substantial basis. The applicant is, therefore, requested to verify the material and environment combinations for the plant-specific containment isolation components, and discuss in detail the provisions which render potential aging effects requiring management and the corresponding AMP to not need to be considered. The applicant is also requested to provide a AMR review for the internal surfaces of containment isolation components, since it is not discussed under Discussion.

Response: Note 1.

3.2.1-D2 In LRA Table 3.2-1, Item 6, for external surface of carbon steel components, and in Table 3.2-2, Item 14, for carbon steel valves, piping and fittings, the applicant applied the same AMR argument as stated in RAI 3.2.1-D1, for excluding the consideration of material susceptibility to corrosion. The applicant is requested to provide the similar additional information as requested in RAI 3.2.1-D1.

Response: Note 1.

3.2.1-D3 In LRA Table 3.2-1, Item 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.

Response: Note 1.

<u>3.2.1-D4</u> In Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, safety injection system and its associated components are listed under component/commodity group Item No. 6, "External surface of carbon steel components". However, two of the four component groups listed, closure bolting and spray additive tank, are not included in LRA Table 2.3-3, for the safety injection system. The applicant is requested to clarify, for the above components, that adequate AMRs have indeed been performed, and that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified.

Response: Note 1.

<u>3.2.1-D5</u> In LRA Table 3.2-1, Item 6, it is stated that carbon steel components in the containment spray system may be subject to corrosion due to aggressive chemical attack. However, in Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, the containment spray system and the associated components, such as closure bolting, spray additive tank, and valves, piping, tubing, and fittings, are not included under component/commodity group Item No. 6, "External surface of carbon steel components". The applicant is requested to clarify, for the above components, that adequate AMRs have indeed been performed, and relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified.

Response: Note 1.

<u>3.2.1-D6</u> In LRA Table 2.3-4, for the containment spray system, "Table 3.2-1, Item No. 9" is referenced under AMR Results, for CV spray pump seal cooler heat exchanger tubing and CV spray pump seal heat exchanger shell and cover. However, in Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, the containment spray system and the above associated components are not included under component/commodity group Item No. 9, "Components serviced by closed-cycle cooling system". The applicant is requested to clarify, for the above components, that adequate AMRs have indeed been performed, and that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified.

Response: This RAI is eliminated because RAI 3.2.1-D5 addressed similar issue.

<u>3.2.1-D7</u> In LRA Table 2.3-4, for the containment spray system, "Table 3.2-1, Item No. 11" is referenced under AMR Results, for closure bolting, containment spray pump seal heat exchanger shell and cover, spray additive tank, and valves, piping, tubing, and fittings. However, in Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, the containment spray system and the above associated components are not included under component/commodity group Item No. 11, "Carbon steel components". The applicant is requested to clarify, for the above components, that adequate AMRs have indeed been performed, and that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified.

Response: This RAI is eliminated because RAI 3.2.1-D5 addressed similar issue.

3.2.1-D8 In a review of NUREG-1801 (Vol. 1) Table 2, and NUREG-1801 (Vol. 2), Chapter V, for the component/commodity group Item No. 10, it is found that this commodity group is to be used for the aging management review of the containment spray and ECCS systems. However, in Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, only RHR system and its associated components, but not the containment spray system and its associated components, are included under component/commodity group Item No. 10, "Pumps, valves, piping, and fittings in containment spray and emergency core cooling systems". The applicant is requested to clarify, for the containment spray system and its associated components, that adequate AMRs have indeed been performed, and that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified.

Response: This RAI is eliminated because RAI 3.2.1-D5 addressed similar issue.

3.2.1-D9 In LRA Table 2.3-2, for the residual heat removal system, "Table 3.2-1, Item No. 11" is referenced under AMR Results, for closure bolting. However, in Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, this component is not included under component/commodity group Item No. 11, "Carbon steel components". The applicant is requested to clarify, for the above component, that an adequate AMR has indeed been performed, and that a relevant material/environment combination, the aging effect requiring management, and the corresponding aging management program have been identified.

Response: Note 1.

3.2.1-D10 In Table 3.2-1, Table 2, of the review tool for the engineered safety features systems, certain containment spray pump components are listed under component/commodity groups Item Nos. 9 and 11, as the carbon steel components for the safety injection system. The applicant is requested to clarify these obvious discrepancies.

Response: This RAI is eliminated because RAI 3.2.1-D5 addressed similar issue.

3.2.1-D11 In LRA Table 2.3-5, for the containment air recirculation system, "Table 3.3-1, Items No. 2, 5, 13, and 16" are referenced under AMR Results, for flexible collars, equipment frames and housings, closure bolting, and heating/cooling coils, respectively. However, in Table 3.3-1, Table 2, of the review tool for the auxiliary systems, the containment air recirculation system and the above associated components are not included all together. The applicant is requested to clarify, for the containment air recirculation system and the above associated components, that adequate AMRs have indeed been performed, and that relevant material/environment combinations, the aging effects requiring management, and the corresponding aging management programs have been identified have been identified.

Response: Note 1.

3.2.1-D12 In Table 2.3-6 and Table 3.2-1 (Row Numbers 3 and 4) of the LRA, 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, please provide a discussion of 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.

The following RAIs are applicable to several components in auxiliary systems and are, therefore, considered general RAIs for auxiliary systems.

Response: Note 1.

3.3: Auxiliary System

3.3-D1 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.

Response: Note 1.

3.3-D2 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.

Response: Note 1.

3.3-D3 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.

Response: Note 1.

3.3-D4 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.

Response: Note 1.

3.3-D5 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 are 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.

Response: Note 1.

The following RAIs are system specific.

3.3.4 Chemical and Volume Control System

3.3.4-D6 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.

Response: Note 1.

3.3.4-D7 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.

Response: Note 1.

3.3.5 Instrument Air System

3.3.5-D8 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.

Response: Note 1.

<u>3.3.6 Nitrogen Supply/Blanketing System</u>

<u>3.3.6-D9</u> 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.

Response: Note 1.

<u>3.3.8 Primary and Demineralized Water System</u>

<u>3.3.8-D10</u> 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.

Response: Note 1.

<u>3.4 - Steam and Power Conversion</u>

<u>3.4.1-D1</u> For the Steam and Power Conversion System in Table 3.4-1, item 8 of the LRA, the applicant credits the Boric Acid Corrosion Program for managing loss of material due to general corrosion for closure bolting. Does the Boric Acid Program inspect the external surfaces of all SPCS closure bolting within the scope of license renewal for external corrosion and not limited to inspection in areas where boric acid wetting is expected, wetted areas, or area where chemical deposits are present?

Response: This RAI is withdrawn, the information is available in the LRA.

<u>3.4.1-D2</u> 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.

Response: Note 1.

<u>3.4.1-D3</u> 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.

Response: Note 1.

<u>3.4.1-D4</u> Table 3.4-1, item 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 2.3-37 for Steam Generator Blowdown System and Table 2.3-31 for the Steam Generator Chemical Addition System also reference Table 3.4-1, item 1 of the LRA and claim to be consistent with GALL but 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.

Response: Note 1.

3.4.1-D5 Table 3.4-1, item 3 of the LRA, the applicant does not manage raw water exposure to AFW piping. 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 backup supplies are "not normally aligned" and how the applicant has verified the AFW piping has not been exposed to raw water.

Response: Note 1.

3.4.1-D6 Table 3.4-1, item 4, RNP aging management review for Auxiliary Feedwater system pump lubricating oil coolers determined that water contamination of lube is not a credible environment because the lube oil system is a closed system. Staff 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, 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 the applicant does not consider water contamination in the lube oil is not a credible environment.

Response: Note 1.

3.4.1-D7 Table 3.4-1, item 5, 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 they use to manage aging for these components is consistent with the GALL. Explain how the applicant can claim that the Systems 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 their own plant specific program.

Response: Note 1.

3.4.1-D8 Table 3.4-1, item 11 in the discussion column states the Condensate Storage Tank at RNP is fabricated of stainless steel and therefore, the GALL AMP for Aboveground Carbon Steel Tank is not applicable. In section 3.4 of the LRA, the applicant does not identify any aging effect requiring management for the external surface of the condensate storage tank. The condensate storage tank at RNP is located in an outside environment and is exposed to sun, weather, humidity, and moisture. Explain why pitting and crevice corrosion are not considered by the applicant to be credible aging effects for the external surface of the condensate storage tank.

Response: This RAI is withdrawn, because no AMP is required for stainless steel under above condition.

<u>3.4.1-D9</u> Table 3.4-1, item 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. Please clarify this is conflicting information.

Response: Note 1.

<u>3.4.1-D10</u> Table 3.4-2, item 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. In Table 3.4-1, item 9, the heat exchangers and coolers/condensers serviced by open-cycle cooling water has the same material and environment as the motor driven AFW pump lube oil heat exchanger waterbox but the applicant does not address loss of material from galvanic corrosion as an aging effect/mechanism that needs to be managed for these components. Please state why the carbon steel steam and motor driven AFW pump lube oil heat exchanger waterbox listed in Table 3.4-2, item 10 is managed for loss of material from galvanic corrosion but the heat exchangers and coolers/condensers serviced by open-cycle cooling water listed in Table 3.4-1, item 9 are not managed for loss of material from galvanic corrosion even though the material and environments are carbon steel and raw water.

Response: Note 1.

<u>3.4.1-D11</u> LRA section 2.3.4 lists SPC systems that are not addressed in GALL but the applicant claims that aging management of these systems are consistent with GALL:

a) 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, items 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 claim to be consistent with GALL? Explain how it is consistent with GALL for the steam generator chemical addition system valves, piping and fittings for the aging management programs in Table 3.4-1, items 1, 2 & 5.

b) Section 2.3.4.7 of the LRA, the applicant states that aging management of the steam cycle sampling system Hx for the SG blowdown is consistent with GALL in table 2.3-9 using links to Table 3.4-1, items 10. Since GALL does not address the steam sample system how can the applicant claim to be consistent with GALL? Explain how it is consistent with GALL for the steam cycle sampling system Hx for the SG blowdown for the aging management program in Table 3.4-1, item 10.

c) 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, item 20. Since GALL does not address the circulating water system how can the applicant claim to be consistent with GALL? Explain how it is consistent with GALL for the circulating water system for the aging management program in Table 3.3-1, item 20.

Response: Note 1.

3.4.1-D12 The staff's review of LRA Section 3.4 found that aging effects associated with two types of materials jointed together, such as carbon steel jointed with stainless steel, are not discussed. Do any components in the steam and power conversion systems consist of dissimilar metals? Can they be subject to loss of material due to galvanic corrosion? If so, identify these components and describe how the aging effects due to galvanic corrosion are managed during the period of extended operation, or provide justification for why loss of material due to galvanic corrosion is not a plausible aging effect.

Response: This RAI is withdrawn because Table 3.4.2, Item 1, adequately covers this issue.

3.4.1-D13 In Table 3.4-2, item 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 claiming that electrolytes level in the SPCS treated water is below the threshold to produce galvanic corrosion.

Response: Note 1.

3.4.1-D14 In Table 3.4-2, item 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). Based on this, the applicant claims 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 carbon steel do not require aging management for loss of material due to external corrosion. The staff position is that carbon steel exposed to air, moisture, or humidity provides an environment for loss of material due to general corrosion for carbon and low alloy steels in both an indoor and outdoor environment. Explain carbon steel components carbon steel exposed to air, moisture, or humidity do not require aging management.

Response: Note 1.

3.4.1-D15 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. 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.

Response: Note 1.

3.4.1-D15 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. 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.

Response: Note 1.

3.4.1-D16 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, item 13, which is the auxiliary system. Is this link to Table 3.3.1 correct or should it be Table 3.4.1, item 13 in the steam and power conversion system table. If Table 3.3.1, item 13 is correct, please explain your basis.

Response: Note 1.

3.5 - Containments, Structures, and Component Supports

3.5.1-D1 Referring to Item 28, Table 3.5-1 of the LRA, It is stated that reactor vessel nozzle supports are inaccessible and not currently inspected under the RNP ASME Section XI, Subsection IWF program and 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.

Response: Note 1.

3.5.1-D2 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 experience no loss of material aging effect without consideration of the condition and pH values of the encasing concrete. Discuss past RNP operating experience with respect to aging effects management of steel components encased in concrete to further support RNP's above determination.

Response: Note 1.

3.5.1-D3 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 intended scope, procedure, concrete functionality criteria and frequency of inspecting the condition of below grade concrete that is exposed during excavation.

Response: Note 1.

3.5.1-D4 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.

Response: Note 1.

3.5.1-D5 Items 2 and 11 of Table 3.5-2 of the LRA state, in part, that RNP AMR determined that stainless steel and galvanized steel components would experience no aging effects requiring management when subject to borated water leaks environment. As applicable, discuss past incidents of borated water leaks 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.

Response: Note 1.

3.5.1-D6 Components listed in items 13 through 16 of Tables 3.5-2 of the LRA are determined by RNP as to experience no aging effects, thus, requiring no AMPs. Discuss pertinent RNP specific, aging management related operating experience including results of past inspections covering these materials (copper alloys, slide bearing plates, liner and penetration insulation, ceiling material and spreading room raised floors) and environments (containment air, indoor-not air conditioned, indoor-air conditioned, out door and borated water leaks) to further justify the above stated AMR determination.

Response: Note 1.

3.5.1-D7 With respect to item 12, Table 3.5-1 of the LRA, Section10.4.3 of the ISI Summary Report referred to in the discussion column states, in part, 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; concluding that the other "inaccessible" areas below the concrete are acceptable for continued service until 2005.

Explain how portion of inaccessible CV liners 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.

Response: Note 1.

3.5.1-D8 Table 3.5-1, Item 16, states that the AMR concluded that above-grade concrete/grout structures have no aging effects. Table 3.5-1, Item 20 states that no aging effects are applicable to masonry walls. Table 3.5-2, Item10 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 believes it is required 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 explain the statement in Table 3.5-1, Item 16, and Item 20, and Table 3.5-2, Item10, why it does not require an aging management program for concrete, masonry blocks and grouts.

Response: Note 1.

3.5.1-D9 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 also states that, owing to the slightly acidic groundwater at there site, the applicant will enhance the inspection requirements 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 as that the applicant has credited the ASME Section XI, Subsection IWL Program, for the Containment Concrete Sump, and the applicant will also perform inspection for below grade concrete. If the applicant disagrees with the staff interpretation, please respond accordingly. The staff is unclear as to how to perform the inspection for below grade concrete. Please clarify the inspection program as to the areas, depth, and frequency of soil excavation.

Response: Note 1.

3.5.1-D10 Table 3.5-1, Item 17, states that 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. The staff interprets the statement as that the applicant have credited the Structures Monitoring Program for inaccessible concrete components, and they will also perform inspection for below grade concrete. If the applicant disagree with the staff interpretation, they need to respond accordingly. The staff position for managing aging effects of in-scope concrete components is provided in 3.5.1-D8. The staff is unclear as to how the applicant would perform the inspection for below grade concrete. Please clarify the inspection program as to the areas, depth, and frequency of soil excavation.

Response: Note 1.

3.5.1-D11 In Table 3.5-1, Item 15, the applicant states that 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. Please state the specific standards that was referenced which would substantiate claim that the RNP concrete does not have the aging mechanism of reaction with aggregates, such as ASTM C295-54 or ASTM C227-50.

Response: Note 1.

3.5.1-D12 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. Please explain the highest temperatures in concrete elements at RNP with respect to general high temperature areas and local hot spots and compare them to the ACI 349 Code temperature limits to substantiate the claim.

Response: Note 1.

3.5.1-D13 Considering the vulnerability of carbon steel structural components, the staff believes that its requires to implement an aging management program to manage the aging of these components. 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 the aging effect. For carbon steel in an indoor-air-conditioned environment, the staff does not require aging management. In addition, for steel imbedded 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.

Response: Note 1.

3.5.1-D14 Item 15 of Table 3.5-1 of the LRA states, in part, that based on the design specifications for the concrete, the RNP AMR determined that the aging mechanisms of freeze-thaw and reaction with aggregates were not applicable to RNP concrete elements. Please confirm that RNP's past operating experience including findings from structural inspections of the exterior dome and wall of RNP containment supports the above AMR determination that no aging mechanism due to freeze-thaw applies to RNP concrete.

Response: Note 1.

3.5.1-D15 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 aging of these concrete tanks.

Response: Note 1.

3.5.1-D16 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 of 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 the administrative leakage limits established for individual bellows which would detect the degradation of bellows during Type B testing?

(c) What would be the frequency of testing penetrations with bellows during the extended period of operation?

Response: Note 1.
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3.5.1-D17 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. They 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?

Response: Note 1.

3.5.1-D18 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 (and will be) by means of Appendix J program. Performance based Option B of Appendix J (of 10CFR50) 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 provide a discussion of 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).

Response: Note 1.

3.5.1-D19 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. The applicant is requested to 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 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.

Response: Note 1.

3.5.1-D20 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 the effective means of preventing corrosion of the tendons and anchorage components.

Neither the GALL report nor Subsection IWL address inspection or monitoring of grouted tendons. 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.).

Response: Note 1.

<u>3.5.1-D21</u> Items 7 and 8 of Table 3.5-2 of the LRA identify aging effects of 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 be managed.

Response: Note 1.

<u>3.6 - Electrical and Instrumentation and Controls</u>

<u>3.6.1-D1</u> 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.

Response: Note 1.

<u>3.6.1-D2</u> 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.

Response: Note 1.

3.6.1-D3 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.

Response: Note 1.

3.6.1-D4 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 determines 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.

Response: Note 1.

4.1 Identification of Time-limited Aging Analysis

4.1-D1 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.

Response: Note 1.

4.2.1 Pressurized Thermal shock

4.2.1-D1 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. Please include in calculations the following items:

1. 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 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 1×10^{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.

Response: Note 1.

4.2.2 Upper Shelf Energy

4.2.2-D1, 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 C_VUSE 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, please provide your calculations of the C_VUSE values for all beltline base-metal and nozzle materials and their associated welds materials, as evaluated through the extended period of operation for RNP. Please include in calculations the following items:

1. Please 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. Please provide any changes, as applicable, to baseline unirradiated C_VUSE values for the beltline materials.

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

4. Please provide, as applicable, the relevant C_VUSE 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.

Part 2: Section IV.A.2 of 10 CFR Part 50, Appendix G, requires that EMAs for USE be approved by the Director of the Office of Nuclear Reactor Regulation, or his/her designee. State whether or not the 60-year EMA analysis in WCAP13587, Revision 1, has been submitted onto the RNP "docket" for staff review, and has been approved by the staff. If WCAP-13587, Revision 1, has not been submitted onto the RNP "docket" for staff review, submit the report for review and approval as part of your response to RAI 4.2.2.2-1. Please include an appropriate proprietary affidavit if WCAP13587, Revision 1, is considered to be a proprietary report under the provisions of 10 CFR 2.790.

Response: Note 1.

4.2.3 Other Analyses

4.2.3-D1 Please confirm that the P-T limits and LTOP limits are TLAAs in accordance with definition for TLAAs in 10 CFR 54.3(a).

Response: Note 1.

4.2.3-D2, 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 be 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). Please 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)(ii).

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), please provide your FSAR supplement description for the RNP P-T and LTOP limits, as applicable to the period of extended operation.

Response: Note 1.

4.3 Metal Fatigue

4.3-D1 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.

Response: Note 1.

4.3-D2 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.

Response: Note 1.

4.3-D3 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 (@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 theTLAA 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.

Response: Note 1.

4.3-D4 Section 4.3.1.2 of the LRA states that if a significant @T 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 @T limit would be addressed. Please provide these information and the RNP specific @T limit during heatup and cooldown.

Response: Note 1.

4.3-D5 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.

Response: Note 1.

4.3-D6 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 please provide your assessment of the environmental effects on the fatigue analyses for these pressurizer components and the surge line.

Response: Note 1.

4.3-D7 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. Please 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 please 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.

Response: Note 1.

4.3-D8 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 exchanger 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 exchanger 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 exchanger were designed to ASME Section VIII Code requirements. Please provide the fatigue design method for this case.

Response: Note 1.

4.3-D9 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}). Please 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.

Response: Note 1.

4.3-D10 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. Please 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.

Response: Note 1.

4.3-D11 In reference to Section 4.3.5, please 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.

Response: Note 1.

4.3-D12 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.

Response: Note 1.

4.3-D13 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. Please discuss the specific requirement on which the impact allowance was based, and indicate its magnitude.

Response: Note 1.

4.3-D14 Section 4.3.6 of the LRA states that the spent fuel crane is designed for 20,000 to 100,000 load cycles. Please provide the basis for the upper and lower limits.

Response: Note 1.

4.3-D15 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. Please verify that no members of the crane have a lower tensile strength. Also please identify the members with the minimum factors of safety.

Response: Note 1.

4.4 Environmental Qualification of Electrical Equipment

4.4-D1 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.

Response: Note 1.

4.4-D2 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 program. This program will be credited to manage the aging of EQ components. Please provide details of this program.

Response: Note 1.

4.4.1 Electrical and I&C Component Environmental Qualification Analyses

4.4.1-D1 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 (RPN). 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-D2.

Response: Note 1.

4.4.1-D2 The LRA does not address whether there have been any major plant modifications or events at RNP of sufficient duration to have changed the temperature and radiation values that were used in the underlying assumptions in the EQ calculations, and whether the conservatism in the EQ equipment qualification analyses are sufficient to absorb environmental changes occurring due to plant modification and events. Also, 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.

Response: Note 1.

4.4.1-D3 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.

Response: Note 1.

4.4.1-D4 In the LRA Section 4.4.1, the applicant stated that the following paragraphs describe the thermal, radiation, and wear cycle aging effects that 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.

Response: Note 1.

4.4.1-D5 Please provide details regarding total integrated dose through the period of extended operation from the 40-year values.

Response: Note 1.

4.4.1-D6 Please provide analyses for the items identified below to illustrate the basis upon which the analyses were projected to the end of the period of extended operation. Each analysis should include a discussion on the analytical methods used and why they are applicable, the data collection and reduction methods used, the underlying assumptions, the acceptance criteria, and the corrective actions if the acceptance criteria are not met. In addition, please provide a list of all equipment for which an activation energy different from that in the current qualification basis documents was used in the re-analysis, along with the justification for using a different value.

a) 4.4.1.2 - ASCO Solenoid Valves- AQR Report

b) 4.4.1.4 - Limitorque Model SB-3 and SBM -00 MOV Actuators- inside containment

c) 4.4.1.5 - Rockbestos Cable - Firewall III

d) 4.4.1.11- Westinghouse Motors - Frame 506 UPZ, 509US, and SBDP - RHR, SI Pumps, HVA 6A, 8A, & 8B

e) 4.4.1.13 - Crouse-Hinds Electrical Penetration Assemblies

f) 4.4.1.26 - Kerite HTK Power Cable

g) 4.4.1.31 - Westinghouse CET/CCM - Incore T/C Connectors and MI cable Assemblies

h) 4.4.1.34 - Gamma- Metrics Excore Neutron Detectors

i) 4.4.1.43 - Cable - PVC and XLPE Outside Containment

j) 4.4.1.44 - Grease - Motors and MOVs

k) 4.4.1.19 - Raychem Splices - NPKV Stub Kits

l) 4.4.1.45 - Target Rock Solenoid Valves

Response: This RAI is withdrawn because this information was provided in form of Environmental Qualification data package.

4.4.1-D7 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 investigate the staff's concern on this issue.

Response: Note 1.

4.4.1-D8 Motor aging due to a wear cycle is not addressed in 4.4.1.11 (EQDP - 8.1, Rev. 6). Please explain the reason.

Response: Note 1.

4.4.1-D9 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.

Response: Note 1.

4.4.1-D10 Please provide additional discussion of the short duration periods that power cables are energized discussed in section 4.4.1.43 of the LRA. 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.

Response: Note 1.

4.4.1-D11 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.

Response: Note 1.

4.4.1-D12 Sections 4.4.1.3, 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.

Response: Note 1.

4.5 Containment Tendon Loss Prestress

4.5-D1 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.

Response: Note 1.

4.5-D2 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 in service inspection, component replacement, and re-tensioning, as required.

The RNP 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 prestressing levels during the extended period of operation.

Response: Note 1.

4.5-D3 The applicant is requested to justify why the information sought in RAI 4.5-D1 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 is that information is presented.

Response: Note 1.

4.6.1 Thermal Aging Embrittlement

4.6.1-D1 Please state whether WCAP-15363, Revision 0, and WCAP-15363, Revision 1, have been submitted and reviewed by the staff for approval. If the reports have been submitted for review and approved by the staff, please provide the references to the staff’s safety evaluations that were issued in approval of the fracture mechanics methodologies specified in the topical reports for the reactor coolant pump casings. If the reports have not been submitted for review, please submit the reports on the "docket" for RNP (Docket No. 50-261).

Response: Note 1.

4.6.3 Elimination of containment Penetration Coolers

4.6.3-D1 Section 4.6.3 of the LRA states that, "In addition, the steady-state temperature without cooling water and continuous RHR flow at 380@F results in the temperature of the surrounding concrete of approximately 210@F." Please define the steady-state temperature. Is the temperature in the hot pipe containment penetration at 380@F considered as a normal operating condition? Is the temperature in the concrete that surrounds the hot pipe penetration at approximately 210@F considered as a normal operating condition? If answers to these questions are positive, please justify your results since ACI 349 Code limitation of 200@F has been exceeded. Please describe how the 210@F was obtained(e.g., measured or calculated).

Response: Note 1.

4.6.3-D2 The LRA states that, "The analysis of concrete temperature determined that the allowable number of cycles of heatup and cooldown, at 40 hours or less per cycle, was 252 cycles." What are the heatup and cooldown temperatures used in the analysis? Was there a thermal fatigue analysis for concrete? Based on the analysis, after 252 cycles, please describe the expected condition of concrete, such as disintegration or loss of strength. Please describe the analysis concept and procedures, and submit the analysis results at the end of 252 cycles.

Response: Note 1.

4.6.3-D3 The LRA states that, "the projected number of cycles for 60-year of operation (120 cycles) is less than the allowed number of cycles for penetration S-15 (252 cycles), ..." Please justify the 120 cycles in 60-year of operation, accounting for shutdowns due to maintenance or other reasons.

Response: Note 1.

4.6.4 Aging of Boraflex

4.6.4-D1 The applicant stated in its application that prior to the extended period of operation, either an analysis will be performed to permit elimination of the credit for the Boraflex panels in the spent fuel racks in determining K_{eff} for the spent fuel array or credit will be used and the current Boraflex Monitoring Program will be evaluated against the 10 elements for an acceptable license renewal aging management program documented in the GALL report. Please provide the basis for the decision and the decision to either eliminate credit for the Boraflex or continue with the Boraflex Monitoring Program.

Response: Note 1.

4.6.4-D2 Measurement of boron areal density (BADGER) in conjunction with a predictive code (RACKLIFE) has been shown to be a conservative method of determining the amount of Boraflex degradation. The staff believes that the use of BADGER testing in combination with a predictive code, i.e, RACKLIFE, provides the best method for determining the Boraflex degradation. Sampling and analysis of silica concentration can help determine the average Boraflex loss but would not identify the most degraded panel. Please provide information on how often is the silica concentration measured and the degradation rate of the Boraflex panels.

Response: Note 1.

4.6.4-D3 In its response to NRC Generic Letter 96-04, the applicant stated that using the long term coupon program, monitoring the silica concentration in the spent fuel pool and comparison of silica concentration with industry data provides assurance that a 5% subcriticality margin can be maintained. Since Boraflex degrades at different rates for different locations in the same pool, it would not be appropriate to compare the silica concentration in different spent fuel pools to conclude the degree of degradation in one spent fuel pool is less than in another pool. Inspection of Boraflex coupons can provide information of the rate at which the Boraflex panels are degrading; however, these coupons are smaller in size and are affected by their location in the spent fuel pool. Please provide the following information: (a) a discussion of the basis used to determine that a 5% sub-criticality margin is maintained by examining the removed coupons, (b) a discussion of the types of tests performed on the coupons that are removed and the location of the coupons with respect to the fuel assemblies (top, bottom, middle).

Response: Note 1.

Appendix B - Aging Management Program

B.2.1 ASME Section XI, Subsection IWB, IWC and IWD Programs

B.2.1-D1 The inservice examination for steam generator shell welds governed by ASME Section XI Table IWC-2500-1, Examination Category C-A, requires volumetric examination of circumferential welds. The discussion section of Item 2 in LRA Table 3.1-1 focuses on the issue raised in IN 90-04 and addressed in Item D1.1-c of the GALL Table IV.D1 that during ultrasonic examination of these welds, signal from flaws in the weld are likely to be masked by the corner-trap signal from the geometric irregularity in the steam generator upper shell-to-transition cone girth weld.

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

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

Response: Note 1.

B.2.2 Water Chemistry

B.2.2-D1 The applicant stated in its application that the Water Chemistry Program implements later revision of the EPRI guidelines for Primary and Secondary Water Chemistry. Please discuss whether any differences exist between the applicant's water chemistry program and the referenced program.

Response: Note 1.

B.2.2-D2 The applicant stated in its application that the Water Chemistry Program has been subject to periodic internal and external activities. Please explain what kind of activities were performed and the results of the activities.

Response: Note 1.

B.2.2-D3 The applicant stated in its application that it has developed a new program to address one time inspections to demonstrate the adequacy of the water chemistry controls. Please discuss the criteria that the applicant has used to select which piping will be evaluated to confirm the effectiveness of the Water Chemistry Program.

Response: Note 1.

B.2.4 Steam Generator Tube Integrity Program

B.2.4-D1 The applicant stated that the steam generator tube integrity program was performed under the "overall" steam generator program at the Robinson Nuclear Plant (RNP). Please discuss in detail the "overall" steam generator program and, in particular, the steam generator tube integrity program at RNP. Please describe any differences between the two programs.

Response: Note 1.

B.2.4-D2 The applicant presented a table of steam generator components with associated aging effect and aging mechanism.

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

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

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

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

Response: Note 1.

<u>B.2.4-D3</u> The applicant identified cracking and loss of material as the aging effects and stress corrosion cracking, crevice corrosion, and fretting as the aging mechanisms for the anti-vibration bars. The staff believes that the tubes, when in contact with the anti-vibration bars, would experience these aging effects, but the anti-vibration bars would not experience such aging effects. The safety concerns in general have been on the tubes, not on anti-vibration bars. The staff's observation is based on the industry experience. Therefore, the applicant should clarify whether the anti-vibration bars are correctly identified in the table.

Response: This RAI is withdrawn, because the information is available within the LRA.

<u>B.2.4-D4</u> By a letter dated March 16, 1998, the applicant responded to NRC Generic Letter 97-05, "Steam Generator Tube Inspection Guidelines." In the letter, the applicant stated that it is committed to implement the guidance of NEI 97-06 with exceptions. The staff has the following questions:

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

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

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

Response: Note 1.

<u>B.2.4-D5</u> In the March 16, 1998, letter, the applicant discussed two exceptions to NEI 97-06. Exception number two was related to NEI 97-06, section 2.2, "Accident-Induced Leakage Performance Criterion." The applicant stated, in the letter, that the RNP updated final safety analysis report (UFSAR) does not calculate radiological doses to the control room; therefore, the NEI 97-06 leakage performance criterion will only be applied to radiological dose calculations contained in applicable analyses in the UFSAR. The staff is not clear at this time whether the applicant will take this exception in terms of LRA. If this exception will be taken in the LRA, the staff has the following questions:

A. Please explain what applicable analyses in the UFSAR the applicant is referring to.

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

C. Please describe the condition monitoring assessment and operational assessment that have been and will be performed.

Response: Note 1.

B.2.4-D6 The applicant stated that "...RNP steam generator tube integrity program is continually upgraded based on industry experience and research via the Operating Experience and Self-Assessment Programs..."

A. Please describe in detail how the steam generator tube integrity program is upgraded via the Operating Experience and Self-Assessment Programs.

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

Response: Note 1.

B.2.4-D7 Please discuss how steam generator tube leakage integrity is managed (i.e., what is the shutdown criteria when a leak occurs and guidance used) and please describe in detail how tube leakage is monitored at RNP.

Response: Note 1.

B.2.4-D8 Please provide all steam generator components that are covered under the steam generator tube integrity program other than those components that have been provided in the table on page B-14.

Response: Note 1.

B.2.6 ASME Section XI - IWF

B.2.6-D1 In LRA Section B.2.6, "ASME Section XI, Subsection IWF Program", it is stated that in the evaluation of the IWF program against the program elements of the GALL Report, exceptions to Code requirements that have been granted by approved relief requests were not considered to be exceptions to the GALL criteria. Please explain what those relief requests are, and the basis of their not being considered as exceptions to the GALL criteria.

Response: Note 1.

B.2.6-D2 In LRA Section B.2.6, "ASME Section XI, Subsection IWF Program," the applicant listed loss of material due to general corrosion to be the only aging effect/mechanism of concern. The applicant also stated that its IWF program examines hangers for loss of mechanical function, however, loss of mechanical function was not identified as an age-related degradation in the RNP aging management review. Please elaborate on the extent the hangers are examined for loss of mechanical function, following its IWF program, and explain why loss of mechanical function for hangers was not identified as an age-related degradation in its aging management review. Please note that in GALL, Section XI.S3, "ASME Section XI, Subsection IWF Program," under "Parameters Monitored or Inspected," it is stated that VT-3 visual examination will be used to monitor or inspect component supports for corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close tolerance machined or sliding surfaces, and missing, detached, or loosened support items. In addition, the GALL program states that the visual examination would be expected to identify relatively large cracks. Discuss how your IWF program was considered to be consistent with the GALL IWF program, considering conformance of all the relevant program elements.

Response: Note 1.

B.2.7 10 CFR PART 50, APPENDIX J PROGRAM

B.2.7-D1 The applicant credits the 10 CFR Part 50, Appendix J Program for aging management of selected components of the Reactor Containment Building at RNP. The applicant identifies the aging effects/mechanisms of concern as; (1) Cracking due to elevated temperature, (2) Cracking due to thermal fatigue, (3) Change in material properties due to elevated temperature, (4) Loss of material due to general corrosion, wear, aggressive chemical, crevice corrosion, galvanic corrosion, and pitting. A number of degradations of concerns cited above cannot be readily detected by performing leakage rate tests as described in the GALL Section XI.S4. The applicant is requested to provide a clear description of the purpose of the program that would be consistent with GALL Section XI.S4, or is requested to develop the ten elements of the program that would be consistent with the intended use of the program. In the later case, the applicant is requested to provide information as to how the leaktight integrity of the containment will be maintained during the extended period of operation.

Response: Note 1.

B.2.7-D2 In the element "Scope of Program" of GALL Section XI.S4, the program provides an option for leakage testing of containment isolation valves: (1) under Appendix J, Type C test, or (2) along with the tests of the systems containing isolation valves. The applicant is requested to provide information as to which of the options (is) will be used during the extended period of operation.

Response: Note 1.

B.2.7-D3 In the operating experience, the applicant states, "Several Condition Reports have been generated as a result of as-found conditions or as a result of assessments (site and corporate)." The applicant is requested to provide a summary of condition reports where significant as-found leakages (Type A, Type B, and Type C tests) were found (e.g., more than twice the acceptance criteria), including the corrective action taken. This information is requested to assess the soundness of the implementation of this existing program.

Response: Note 1.

B.2.7-D4 In the brief outline of the program in Section A.3.1.7 of the UFSAR Supplement, the applicant characterizes the program that consists of inspections of accessible surfaces of containment and monitoring of leakage rates through containment pressure boundary. Moreover, the applicant states that the program implemented in accordance with 10 CFR Part 50, Appendix J, Regulatory Guide (RG) 1.163, and NEI 94-01, Rev. 0. These documents provide generic requirements (in Appendix J) and guidance (in NEI 94-01 and RG 1.163). The RNP containment related acceptance criteria and basis for leak rate testing are in Plant Technical Specification. The UFSAR, in general, is a plant specific report of applicant’s commitments. The applicant is requested to provide justification for not referencing the plant specific technical specification requirements and acceptance criteria in the UFSAR Supplement.

Response: Note 1.

B.2.8 Flux Thimble Eddy Current Inspection Program

B.2.8-D1 Please confirm that eddy current testing techniques (ET) will be used to monitor for vibration-induced wear in the incore flux thimble tubes, as implied in the name of the aging management program (Flux Thimble Eddy Current Inspection Program). If other volumetric inspection methods may be used as alternatives to ET, please state what the inspection techniques are.

Response: Note 1.

B.2.8-D2 When taken in context with each other, the applicant's [Detection of Aging Effects] and [Monitoring and Trending] program attributes for the Flux Thimble Eddy Current Inspection Program imply that the applicant has or will perform an analysis that projects the wear in the incore flux thimble tubes over time and that the frequency of examinations performed on the thimble tubes will be based on anticipated wear that is extrapolated from the wear rates established in the analysis.

The applicant has not provided a definitive frequency for the volumetric examinations of the incore neutron flux thimble tubes as requested in NRC Bulletin 88-09. With regard to the frequency of examinations for the incore flux thimble tubes, either please propose a definitive frequency for the examinations (i.e., every refueling outage, etc.) or, if the frequency of examinations is to vary based on the amount of anticipated wear, please submit the wear analysis for the incore neutron flux thimble tubes for review. Please provide justification how the frequency method selected will provide assurance that wear in the thimble tubes will be detected prior to loss of safety function in the thimble tubes (i.e., loss of thimble tube structural integrity and/or loss of neutron flux monitoring capability). Please note that, if a wear analysis for the incore neutron flux thimble tubes has already been performed and the wear analysis is based on time-limited assumptions over 40 years of licensed plant life, a TLAA is needed under the definition provisions for TLAAs in 10 CFR 54.3 and the TLAA must be included as part of the technical contents of the applications as required under 10 CFR 54.21(c) and must satisfy either the requirements of 10 CFR 54.21(c)(1) or 10 CFR 54.21(c)(2).

Response: Note 1.

B.2.8-D3 The applicant [Acceptance Criteria] program attribute only states what correction action will be done if acceptance criteria for the program are exceeded but does not specifically state exactly what the acceptance criteria are for the Flux Thimble Eddy Current Inspection Program. Please provide the specific acceptance criteria for wear that is detected as a result of implementation of the Flux Thimble Eddy Current Inspection Program.

Response: Note 1.

B.2.8-D4 In applicant's [Operating Experience] program attribute, it is stated that it identified two incore neutron flux thimble tube leakage events. However, the applicant did not state where these events took place (i.e., are they RNP specific or did they occur at other facilities?) and when the leakage was detected. Please provide the time and location of these events and the corresponding License Event Report references that are associated with these events.

Response: Note 1.

B.2.8-D5 UFSAR supplement description for the Flux Thimble Eddy Current Inspection Program (LRA Appendix A, Section A.3.1.8) is written in a manner that does not clearly distinguish whether the Flux Thimble Eddy Current Inspection Program is simply a program that projects the amount of wear that is anticipated to occur in the RNP incore neutron flux thimble tubes, or the Flux Thimble Eddy Current Inspection Program is an inspection-based program that uses ET or other volumetric examinations to detect wear in the thimble and that a wear rate analysis is included within the scope of the program and performed as part of the applicant's bases for scheduling the frequency of examinations to be conducted. Please supplement your UFSAR summary description Flux Thimble Eddy Current Inspection Program with additional details how the program is sufficient to manage wear in the incore neutron flux thimble tubes, and what the scope and purpose of the inspection programs are, and what the program monitors for, and what type of inspection methods the program will be used and what the frequency of examinations are, and what the acceptance criteria are for the program.

Response: Note 1.

B.3.2 Boric Acid Corrosion Program

B.3.2-D1 There is no discussion of strategies that address boric acid leak management for component segments that are inaccessible to visual inspection at the Robinson nuclear plant (RNP). Please discuss whether there are provisions in the boric acid corrosion program to inspect, detect, or monitor boric acid leakage in inaccessible locations.

Response: Note 1.

B.3.2-D2 NRC Generic Letter (GL) 88-05 provides guidance on monitoring the condition of the reactor coolant pressure boundary for borated water leakage. NRC Information Notice 86-108 and three supplements give information on degradation of reactor coolant system pressure boundary resulting from boric acid corrosion. The applicant did not discuss or reference GL 88-05 or Information Notice 86-108 in the boric acid corrosion program in section B.3.2. Please discuss whether the boric acid corrosion program at RNP is consistent with GL 88-05 and whether the program address Information Notice 86-108.

Response: Note 1.

B.3.2-D3 The NRC has issued Generic Letter 97-01, and Bulletins 2001-01, 2002-01, and 2002-02 regarding reactor vessel head degradation caused by boric acid leakage. Please discuss any steps that have been taken in the RNP to satisfy the recommendations in the aforementioned NRC generic communications. Please discuss whether the boric acid corrosion program will be revised to adopt guidance in the aforementioned generic communications.

Response: Note 1.

B.3.2-D4 The applicant stated that as a result of the license renewal review, the scope of the boric acid corrosion program will be enhanced to identify additional areas in which components may be susceptible to exposure from boric acid (e.g.,containment, auxiliary, and spent fuel buildings).

A. The applicant should list specific areas (i.e., buildings) that will be covered by the boric acid corrosion program.

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

C. The applicant should describe its boric acid corrosion program.

Response: Note 1.

B.3.2-D5 The applicant stated that boric acid leakage from the pressurizer is managed by boric acid corrosion program and the ASME Code. Please address why the steam generators and reactor pressure vessel are not included in the boric acid corrosion program.

Response: Note 1.

B.3.3 Flow-Accelerated Corrosion Program

B.3.3-D1 Please discuss flow-accelerated corrosion problems that have occurred in RNP. Describe the current FAC program. Discuss the effectiveness of the FAC program in resolving the past FAC occurrences.

Response: Note 1.

B.3.3-D2 The applicant stated that as a result of the license renewal review, enhancements will be made to the FAC program.

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

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

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

Response: Note 1.

B.3.3-D3 The applicant stated that "...administrative controls for the program will be revised to mandate that corrective actions be taken in accordance with the corrective action program when certain acceptance criteria are not met..." In GALL Section XI.M17, the administrative controls element is not related to the corrective actions element.

A. The staff is not clear if the above statement is consistent with GALL section XI.M17.

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

Response: Note 1.

B.3.3-D4 The applicant stated that several condition reports have been generated as a result of as-found conditions or as a result of assessments (site and corporate). Please describe the condition reports.

Response: Note 1.

B.3.3-D5 In order for the staff to evaluate the acceptability of the Flow Accelerated Corrosion (FAC) program, the applicant should provide a list of the components in the program most susceptible to FAC. The list should include initial wall thickness (nominal), current wall thickness and the future predicted wall thickness.

Response: Note 1.

B.3.3-D6 The Flow Accelerated Corrosion (FAC) program in the applicant's plant includes prediction of the wall thinning for the components susceptible FAC. The wall thinning is predicted by the EPRI's CHECWORKS computer code. In order allow the staff to evaluate the accuracy of these predictions, the applicant should provide a few examples of the components for which wall thinning is predicted by the code and at the same time measured by UT or any other method employed in the applicant's plant. This procedure will show the effectiveness of CHECWORKS in predicting the as-found condition.

Response: Note 1.

B.3.4 Bolting Integrity

B.3.4-D1 In LRA Section B.3.4, "Bolting Integrity Program", cracking is not considered as an aging effect of concern specifically identified with regard to bolting integrity. In GALL, Section XI.M18, "Bolting Integrity", cracking is identified specifically as an aging effect requiring management. Please discuss the inconsistency between the RNP bolting integrity program and its counterpart program in GALL.

Response: Note 1.

B.3.6 Overhead Load Handling

B.3.6-D1 Please provide the specific Service Class (such as CMAA Specification # 70 or # 74) to which the cranes within the scope of license renewal were designed.

B.3.6-D2 It is stated in Section B.3.6 of the LRA that enhancements will be made in the scope of the program so that the cranes will be inspected using the attribute inspection checklist for structures. Provide a summary of this attribute inspection checklist.

B.3.6-D3 Please provide clarification whether or not the effects of wear on the rails will be managed as required by GALL Section XI.M23 "Overhead Heavy and Light Load Handling Systems". Also please indicate how rail wear would be managed

B 3.8 Buried Piping and Tanks Surveillance Program

B.3.8-D1 The applicant stated that the buried piping and tanks surveillance program is credited for aging management of selected components in the fuel oil system. Please provide a list of specific buried pipes and components that are covered under this program.

Response: Note 1.

B.3.8-D2 The applicant stated that the program elements will be enhanced to review and update cathodic protection procedures and to install pressure taps and perform leak testing on the underground fuel oil piping.

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

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

Response: Note 1.

B.3.8-D3 The applicant has taken several exceptions to GALL XI.M28, “Buried Piping and Tanks Surveillance” The applicant stated that it uses the guidance in NACE RP-0169-76 in lieu of NACE RP-0169-96 as recommended in GALL XI.M28. The applicant stated that the aforementioned enhancements to review and update, as necessary, cathodic protection procedures to ensure consistency with the 1996 NACE standard. The staff is not clear that the proposed enhancements would make the 1976 standard consistent with the 1996 standards. Please provide information to show that the 1976 standard and proposed enhancements satisfy the NACE 1996 standards and NACE Standard RP-0285-95 that GALL XI.M28 also recommends.

Response: Note 1.

B.3.8-D4 GALL XI.M28 recommends that the coating conductance versus time or the current requirement versus time be monitored to provide an indication of the coating condition and effectiveness of the cathodic protection system when compared to predetermined values. The applicant stated that in-situ measurement of coating conductance is not considered prudent due to the potential to cause coating damage. The applicant also stated that it has no documentation of initial coating conductance. Please provide parameters that will be monitored to assure the integrity of the coating on the buried pipe (the applicant stated that there are no buried tanks in this program).

Response: Note 1.

<u>B.3.8-D5</u> Please describe the cathodic protection system installed on the buried piping and the coating material used on the buried pipe.

Response: Note 1.

<u>B.3.8-D6</u> The applicant reported that degradation of the cathodic protection system found in 1988 was caused by installation of concrete in the yard and that an inspection of emergency diesel generator fuel oil underground piping showed that the piping coating was intact with no detectable piping degradation. Please discuss if piping coating on buried piping other than diesel generator fuel oil piping that were covered under this program were inspected to be acceptable.

Response: Note 1.

<u>B.3.8-D7</u> The applicant stated that it completed a hardware upgrade of the cathodic protection system and established base line operating parameters.

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

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

Response: Note 1.

<u>B.3.8-D8</u> If the leakage in buried pipes is not detected by inspection (i.e. excavation), please discuss whether there are other measures that could detect such leak before the leakage challenges the intended function of the system.

Response: Note 1.

<u>B.3.8-D9</u> The applicant stated that the combined activities in this program and Buried Piping and Tanks Inspection Program in Section B.3.12 of the LRA will manage aging effects on buried piping and tanks. However, the buried piping and tanks inspection program is credited to manage the aging effect of loss of material due to galvanic corrosion whereas this program does not. Please clarify why galvanic corrosion is not included in this program.

Response: Note 1.

<u>B.3.9 Above Ground Carbon Steel Tanks Program</u>

<u>B.3.9.D1</u> The applicant stated that the above ground carbon steel tanks program is credited for aging management of tanks in the fuel oil system. Please provide a list of components covered under this program and discuss whether there are tanks made with materials other than carbon steel that should be considered in the program.

Response: Note 1.

B.3.9-D2 The applicant described an operating experience in which a loss of diesel fuel from the Unit 1 turbine fuel oil tank was detected. The root cause was attributed to pitting corrosion on the inside surface of the tank.

A. Please provide more detail of the unit 1 turbine fuel oil tank leak event. For example, discuss the root cause of the pitting corrosion inside the tank and provide the flaw size that caused the leak and the thickness of the tank wall.

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

Response: Note 1.

B.3.9-D3 The applicant stated that the above ground carbon steel tank program is credited for the exterior surface of the carbon steel tanks. However, if this program covers only the outside surface and not the inside surface of the tank, please discuss how the integrity of the inside surface of the tank is assured in light of turbine fuel oil tank leak which was caused by the corrosion in the inside surface.

Response: Note 1.

B.3.9-D4 The applicant stated that the unit 1 turbine fuel oil tank are now scheduled for inspections on a five year cycle. GALL XI.M29, “Above Ground Carbon Steel Tanks,” recommends system walkdowns during each outage.

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

B. Please discuss the inspection procedures in detail.

Response: Note 1.

B.3.9-D5 The applicant stated that this program takes exception to GALL XI.M29. The applicant stated that thickness measurements will not be performed on tank bottoms to detect exterior corrosion because the tanks are protected from corrosion by the cathodic protection system and the oily sand that is located underneath of the tanks.

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

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

Response: Note 1.

B.3.9-D6 The applicant stated that the program will be enhanced to assure that external surfaces of the fuel oil tanks are inspected periodically and to include corrective actions. Please discuss the documentation process of these enhancements to ensure that the applicant's commitment is properly recorded.

Response: Note 1.

B.3.10 Fuel Oil Chemistry Program

B.3.10-D1 The applicant stated that the fuel oil chemistry program is credited for aging management of selected components in the fuel oil system in RNP. Please specify each components and systems that will be covered by the fuel oil chemistry program.

Response: Note 1.

B.3.10-D2 The applicant stated that the administrative controls for the fuel oil chemistry program will be enhanced to improve sampling and de-watering of selected storage tanks. Please discuss the enhancement to improve the sampling and de-watering process. Please specify which storage tanks will be selected and which will not be selected. Please discuss the selection criteria.

Response: Note 1.

B.3.10-D3 The applicant stated that it will formalize existing practices for draining and filling the diesel fuel oil storage tank and bacteria testing for fuel oil samples from various tanks. Please discuss the formalization process. Please discuss briefly the procedures of bacteria testing.

Response: Note 1.

B.3.10-D4 The applicant discussed several events related to degraded fuel oil tank and fuel oil contamination. However, on page B-45, second paragraph, the applicant stated that no adverse bacteria had been identified and results of chemical testing show bulk average oil conditions have always been within specifications.

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

B. Please discuss the specifications to which the oil conditions were compared. Please discuss the acceptance criteria of fuel oil (This question is related to Question B.3.10-D8).

Response: Note 1.

B.3.10-D5 The applicant identified several exceptions to GALL section XI.M30, Fuel Oil Chemistry. One of the exception is that the fuel oil chemistry program in RNP is used to manage aging effects on all system components "wetted" by fuel oil. This results in additional materials in RNP being in scope beyond those in the GALL report. The applicant should specify each of the additional materials beyond those in the GALL report.

Response: Note 1.

B 3.10-D6 The applicant is taking exception to the one-time inspection. GALL VII.H1, Diesel Fuel Oil System, specifies that for the internal surface of a carbon steel tank the fuel oil chemistry program be augmented by a one time inspection in accordance with GALL Section XI.M32. The applicant stated that a one-time inspection of small, elevated, diesel fire pump fuel oil tank and diesel generator day tanks is not warranted because the small tanks have limited access to the tank internals making it impractical to clean and perform a meaningful inspection. The applicant stated that ultrasonic testing is also considered inappropriate to detect small amounts of pitting in tanks constructed of carbon steel that is measured in units of gauge thickness. The applicant also stated that on the basis of operating history, external tank and structure inspections are considered sufficient to identify degradation in the tank walls.

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

B. Please discuss degradation history of all tanks that contain fuel oil in RNP and are in the scope of aging management review.

C. The staff does not believe that the external and structure inspections will detect degradation on the inner surface of the tanks. Please discuss how the external inspection can assure the integrity of the inner surface of the tank.

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

E. If ultrasonic testing is inappropriate to detect degradation in tanks, the applicants should suggest other nondestructive examination to inspect the inner surface of the tanks.

Response: Note 1.

B.3.10-D7 The applicant is taking exception to Detection of Aging Effects in the GALL report. The applicant stated that ultrasonic thickness measurements of bottoms of large storage tanks are not typically performed at RNP unless warranted by the level of coating degradation and corrosion found during inspection. The applicant should to demonstrate how the thickness of the tank bottom will be verified without ultrasonic measurements. Please discuss the current procedures in RNP in verifying tank bottom thickness.

Response: Note 1.

B.3.10-D8 The applicant is taking exception to GALL section XI.M30 regarding fuel oil standards. The applicant will use alternate standards and acceptance criteria for fuel oil sampling at RNP in place of ASTM standards D 1794, D 2709, D 4057, and modified ASTM D 2276, which are recommended in the GALL report. The applicant should demonstrate that its alternate standards and acceptance criteria are consistent with the ASTM standards.

Response: Note 1.

B.3.10-D9 The applicant is taking exception to GALL section XI.M30 regarding fuel oil additives. The applicant stated that based on operating history and fuel oil management activities, biocides, biological stabilizers and corrosion inhibitors are not necessary and are not used in the fuel oil at RNP. GALL section XI.M30 states that the quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. On page B-44, the applicant has suggested that there has been cases of degraded oil events occurring in RNP. Please clarify how would the quality of diesel fuel oil in RNP be maintained without these additives.

Response: Note 1.

B.3.10-D10 In its conclusion, the applicant stated that its fuel oil chemistry program is consistent with GALL section XI.M30. However, the applicant did not provide sufficient information on the fuel oil chemistry program to support its conclusion. In addition, the applicant is taking major and significant exceptions to GALL section XI.M30. To demonstrate that its fuel oil chemistry program is consistent with the GALL report, the applicant needs to do the following:

A. The applicant should respond to each of the program elements in GALL section XI.M30

B. The applicant should resolve the staff's concerns regarding the above exceptions

C. The applicant should demonstrate that its current fuel oil chemistry program is within the current licensing basis.

Response: Note 1.

B.3.11 Reactor Vessel Surveillance Program

B.3.11-D1 In regard to the Reactor Vessel (RV) Surveillance Program, Please clarify what evaluation and test criteria will be used as part of the Surveillance Capsule X testing for determining whether the short period of low-temperature operation had any adverse effects on the material properties for the RNP beltline RV materials. In addition, please provide the RV surveillance capsule withdrawal schedule for RNP, as it relates to assurance the withdrawal and testing of RNP RV surveillance capsule specimens will provide relevant material property data for the RNP beltline material over the period of extended operation, and please provide your basis how the RV Surveillance Program is consistent with the recommended RV surveillance capsule withdrawal and testing program outlined in GALL Program XI.M31.

Response: Note 1.

B.3.11-D2 In regard to the USFAR supplement summary for the RV Surveillance Program, please clarify that the RV Surveillance Program will be implemented in accordance with the appropriate requirements of 10 CFR Part 50, Appendix H for RV materials surveillance programs (not the NRC's recommend guidelines of RG 1.99, Revision 2), and that the data obtained through fracture toughness testing will be used in the applicant's calculations of the RNP P-T and LTOP limits, as required by Section IV.A.2 of 10 CFR Part 50, Appendix G, of USE values, as required by Section IV.A.1 of 10 CFR Part 50, Appendix G, and of RT_{PTS} values, as required by 10 CFR 50.61 for PTS evaluations.

Response: Note 1.

B.3.12 Buried Piping and Tanks Inspection Program

B.3.12-D1 The applicant stated that it will combine this program and the buried piping and tanks surveillance program as discussed in Section B.3.8 of the LRA to manage aging effects associated with the buried piping and tanks.

A. As was discussed in Section 3.8, please confirm that there are no buried tanks covered under this program. (B) please provide a list of all buried pipes and their materials of construction that are covered under this program. (C) This program covers buried cast iron piping and fittings which the surveillance program does not cover, please discuss why section B.3.8 of the LRA does not cover buried cast iron piping and fittings.

Response: Note 1.

B.3.12-D2 The applicant stated that leaks have occurred in the north service water header pipe in July 1995, and in March and September 1998.

A. The applicant stated that other buried pipe on site has not exhibited exterior corrosion such as experienced on the north service water header. Please discuss how the exterior condition of other buried pipe was known unless the applicant performed an inspection via excavation and whether all the buried pipes were inspected via excavation.

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

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

Response: Note 1.

B.3.12-D3 The applicant stated that periodic excavations of buried piping for inspection are not warranted.

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

B. Please discuss the inspection history and results of all buried pipe covered under this program. If a buried pipe covered under this program has never been inspected since the commercial operation of the plant, demonstrate that the cathodic protection system on the buried pipe is within the specifications and the integrity of the buried pipe is acceptable prior to entering into the extended period of operation.

Response: Note 1.

B.3.12-D4 In section B.3.8, the applicant stated that in an NRC inspection of a degraded cathodic protection system of a buried pipe, the NRC concluded that about 7 years of cathodic protection could be assured following the system's installation because the cathodic protection system was known to have been operated outside of its original specification. Also, in Section B.3.12, the applicant stated that the leak occurred in the north service water header pipe was caused by the improper installation of the coating material. In light of these two observations,

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

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

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

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

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

Response: Note 1.

B.3.12-D5 The applicant stated that if coating failures occur, there will be ample time to identify and repair leaks before catastrophic failure.

A. Please discuss how much time is allowed to identify the pipe leak before the leak would challenge the intended function of the system.

B. Please discuss the consequence and safety significance of a catastrophic failure in each of the buried piping system.

C. Please discuss the potentials for operator actions to prevent catastrophic failure, given a leak has occurred.

Response: Note 1.

B.3.12-D6 The applicant stated that the program will be enhanced by adding certain requirements. Please discuss the documentation process of these enhancements to assure that the applicant's commitments are properly recorded.

Response: Note 1.

B.3.12-D7 The objective of the program in Section B.3.12 is to prevent, monitor, and mitigate exterior corrosion of the buried piping and tanks. However, the program does not address the integrity of the inside surface of the buried pipes. The staff understands that Section B.3.10, Fuel Oil Chemistry program manages the aging effects on the inside surface of the buried fuel oil pipes; however, the fuel oil chemistry program in Section B.3.10 does not specify the inspection of the inside surface of the buried fuel oil pipes.

A. Please discuss whether the program in Section B.3.12 covers the inspection of the inside surface of the buried pipe. If not, discuss whether there is an inspection program to ensure the integrity of the inside surface of the buried pipe.

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

Response: Note 1.

B.3.13 ASME SECTION XI, SUBSECTION IWE PROGRAM

B.3.13-D1 In addressing the program element, "Confirmation Process," the applicant states that the program will be enhanced to require reexaminations, and document that repairs meet the specified acceptance standards. The requirements for supplemental examinations, additional examinations, and documentation of acceptance criteria are parts of Subsection IWE of the ASME Code, as modified by 10 CFR 50.55a ,and referenced in GALL Section XI.S1. The applicant is requested to provide clarification regarding the enhancements (to be implemented during the extended period of operation) which are currently not required.

Response: Note 1.

B.3.13-D2 Based on the database on degradation of moisture barrier between the concrete floor and the cylinder liner, Subsection IWE of Section XI of the ASME Code (as referenced in GALL Section XI.S1) requires 100% examination of moisture barrier once every inspection interval. During the IWE examinations, a number of licensees have discovered degradation of moisture barriers and significant corrosion of liner plates below the concrete floor levels. The applicant is requested to provide technical justification for the exception taken (i.e. one time inspection of this area).

Response: Note 1.

B.3.13-D3 The applicant is requested to provide acceptance criteria for bulging of the liner plate.

Response: Note 1.

B.3.13-D4 Neither the LRA nor the UFSAR Supplement states the Edition and Addenda of the ASME Code being implemented. As amendment of UFSAR is a continuing process, it would be appropriate to state the Edition and Addenda of the ASME Code being used in the UFSAR Supplement. The relief requests granted from the specific Edition and Addenda of the Code should also be listed in the UFSAR Supplement (and in subsequent UFSAR addenda). The applicant is requested to provide information pertinent to the implementation of the program during the extended period of operation.

Response: Note 1.

B.3.14 ASME SECTION XI, SUBSECTION IWL PROGRAM

B.3.14.D1 Because of the high acidity of the soil at the plant site, the staff considers the enhancement appropriate. However, the applicant is requested to provide information regarding the present condition of the below grade concrete basemat based on the inspections performed during certain maintenance activities.

Response: Note 1.

B.3.14-D2 In forth bullet of the operating experience related to the containment concrete degradation, the applicant states "An evaluation concluded that not providing cooling to the penetrations with hot piping does not degrade the concrete. Degradation has not occurred and does not require augmented examinations." Most of the high temperature related degradation would be in the concrete around the liner plate (or insert plate). Any degradation occurring in the area cannot be seen by visual examination. In this context, the applicant is requested to provide the following information;

1) The sustained temperature in the concrete/liner interface around the hot penetrations

2) Use of other NDE examination to ensure that the concrete on the back of the liner is not degraded.

Response: Note 1.

B.3.14-D3 Neither the LRA nor the UFSAR Supplement states the Edition and Addenda of the ASME Code being implemented. As amendment of UFSAR is a continuing process, it would be appropriate to state the Edition and Addenda of the ASME Code being used in the UFSAR Supplement. The relief requests granted from the specific Edition And Addenda of the Code should also be listed in the UFSAR Supplement (and subsequent addenda). The applicant is requested to provide information pertinent to the implementation of the program.

Response: Note 1.

B.3.15 Structures Monitoring

B.3.15-D1 If the SMP manages the protective coatings that are relied upon to manage the effects of managing for structures and components, please describe the inspection program including (1) parameters monitored; (2) inspection interval; (3) inspection methods employed to detect change in material properties; (4) accept/reject criteria; and (5) operating experience to date with respect to degradation occurrences, corrective actions, and current activities.

Response: Note 1.

B.3.15-D2 Appendix B.3.15 of the LRA contains a description of the structures monitoring program(SMP) for aging management of civil structures and components at RNP. The applicant identified aging effects (change in material properties due to elevated temperature and cracking due to elevated temperature) for elastomers (structural sealants). Please provide information on how the SMP manages the effects for elastomers through the effective incorporation of the following 10 attributes: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

B.3.17 Systems Monitoring Program

B.3.17-D1 The LRA lists the aging effects that are covered by this program, but does not contain information related to the parameters monitored or inspected, detection of aging effects, monitoring and trending, or acceptance criteria. Please provide the above information for each aging effect that the Systems Monitoring Program will be used to manage.

Response: Note 1.

B.3.18 Preventive Maintenance Program

B.3.18-D1 The staff has read the program description for this aging management program, and is concerned that it's purpose may overlap the surveillance and maintenance activities associated with 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (e.g., the Maintenance Rule).

In order to better understand how this aging management program will differ from, and supplement, the Maintenance Rule program, please discuss the surveillance and preventive maintenance activities that will be performed by this program, and how they will supplement activities performed under the Maintenance Rule. Please discuss the criteria to be used and the frequency to evaluate the effectiveness of the program in achieving its goals of aging management.

Response: Note 1.

B.3.18-D2 The LRA lists the aging effects that are covered by this program, but does not contain information related to the parameters monitored or inspected, detection of aging effects, monitoring and trending, or acceptance criteria. Please provide the above information for each aging effect that the Preventative Maintenance Program will be used to manage.

B.3.19 Metal Fatigue or Reactor Coolant Pressure Boundary

B.3.19-D1 Section B.3.19 of the LRA discusses the discovery of several additional thermal transients not originally considered in the RNP design. The second sentence under "Operating experience" defines the scope of lines (systems) under NRC Bulletins 88-08 and 88-11, and additional fatigue analyses performed to account for additional thermal transients associated with each of these issues. Please clarify the scope defined in the second sentence and identify any enhancements to the RNP plant specific FMP that resulted from the industry operating experience relating to thermal fatigue and component degradation.

B.3.19-D2 The "conclusion" of Section B.3.19 of the LRA states that the pressurizer surge line (and the nozzles) was not shown to have an environmentally-adjusted CUF less than 1.0 and fatigue effects will be managed by periodic examinations in accordance with ASME Section XI. Referring to RAI 4.3-9, the inspection program can not be considered adequate unless the applicant can demonstrate that the examinations, at the prescribed interval, will be able to detect the initiation of fatigue cracking which will not become unstable. Please provide this demonstration.

B.3.19-D3 Please clarify whether the FMP at RNP covers the environmental effects and describe the methodology employed to account for the environmental effects on the CUF calculations at RNP.

B.4.1 Nickel Alloy Nozzle and Penetration Program

B.4.1-D1 Under "Nickel-Alloy Nozzles and Penetration Program", it is stated that RNP will commit to continuing the resolution of reactor vessel head penetration issues through the period of extended operation and will participate in industry initiatives (Westinghouse Owners Group and the EPRI Material Reliability Program) to ensure that the components managed are maintained within the CLB during the period of extended operation. In order that this commitment will ensure RNP's Nickel-Alloy Nozzles and Penetration Program be capable of monitoring, detecting, evaluating and removal of flaws in the components, please confirm if RNP is committed to any and all actions that are agreed upon between the NRC, NEI, MRP and the industry related to ensuring the integrity of these nozzles in RNP vessel head during the extended period of operation.

Response: Note 1.

B.4.1-D2 Under "Nickel-Alloy Nozzles and Penetration Program", it is stated that RNP will make enhancement to the program by performing corrective actions for augmented inspections using repair and replacement procedures equivalent to those requirements in ASME Section XI. Please confirm if RNP is committed to comply with the ASME Code, Section XI, IWB-4000 for repair of components found to contain cracks and IWB-7000 for replacement of components identified as susceptible to primary water stress corrosion. Please justify RNP's planned enhancement to the program with the Code-equivalent repair procedure.

Response: Note 1.

B.4.2 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program

B.4.2-D1 In your UFSAR supplement summary for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS Program) the applicant states that the flaw tolerance evaluations for RCP casings and primary loop CASS components have been done in accordance with a fracture toughness methodology that has been approved by the NRC, and that, consistent with NRC guidance, the RNP Program does not include additional inspections of pump casings, valve bodies, or piping. Please clarify which fracture toughness methodology and NRC guidance the applicant is referring to in your UFSAR supplement summary for the CASS Program, and provide basis why program is consistent with the NRC guidance.

Response: Note 1.

B.4.3 PWR Vessel Internals Program

B.4.3-D1 The discussion provided in Section B.4.3 of Appendix B to the LRA does not provide any indication of what the exception to the [Preventative Actions] program attribute really is. Please clarify what the exception to the [Preventative Actions] program attribute for the PWR Vessel Internal Program involves and clarify whether the exception taken in your application is really an exception against GALL Program XI.M2, "Water Chemistry," or against GALL Program XI.M16, "PWR Vessel Internals," or both. Please provide your basis for concluding that the inconsistency with GALL Program XI.M2, "Water Chemistry," GALL Program XI.M16, "PWR Vessel Internals," or both would not have any adverse effects on the ability of the program to manage aging effects in the RV internal components.

Response: Note 1.

B.4.3.-D2 The discussion provided in Section B.4.3 of Appendix B to the LRA does not provide any specific details on how the RNP PWR Vessel Internals Program will manage a number of aging effects for the RNP RV internal components. Please provide additional specific details on how the RNP PWR Internals Program will manage the following effects in the RNP RV internal components:

1) void swelling

2) loss of material, loss of preload and cracking in RV internal bolting materials, including baffle/former bolts

3) loss of material and loss of preload in things like clevis inserts, as applicable

4) cracking in RV internals made from austenitic alloys (inconel alloys and/or austenitic stainless steel alloys) and loss of fracture toughness in RV internals made from CASS or in RV internals made from austenitic alloys with neutron fluences projected to be above $5x10^{20}$ n/cm^2

Please include in your assessment of these aging effects, clarify which type of inspection methods will be used to monitor for the aging effects, how often the inspections of the components will be performed, the methods that are used to qualify a given inspection method to detect the aging effect in question, and what acceptance criteria will be used to initiate corrective actions if any of these aging effects are detected in the RV internal components. If industry participation is to be used as a basis for determining whether inspections are necessary for monitoring of these aging effects, please state what commitments will be made to implement the inspections methods, inspection frequencies, inspection qualification techniques, and acceptance criteria for these aging effects as recommended by Westinghouse, applicable MRP ITGs, or other relevant industry organizations.

Response: Note 1.

B.4.3-D3 Section B.4.3 of the LRA credits the PWR vessel internal; program for aging management of selected components of the RNP reactor vessel and internals. Please provide a list of those selected components and the basis of the selection process. Please also indicate the cross reference, whether the fatigue monitoring of the vessel internal components is categorized as part of AMP B.4.3 or B.3.19, “Fatigue Monitoring Program.”

Response: This RAI is withdrawn, because it was covered by final RAI B.4.3-1.

B.4.3-D4 Section B.4.3. of the LRA indicates that WOG and EPRI MRP research projects are completed and RNP will factor the results of these MRPs into the PWR vessel internals program. Please provide a list of MRP projects and MRP reports that you intended to factor into the vessel internal program. Justify the applicability, and cite any exceptions.

Response: This RAI is withdrawn, because it was covered by final RAI B.4.3-1.

B.4.3-D5 Under “Operating Experience” of section B4.3 of the LRA, please clarify the following statement: “NRC Information Notice 98-11 was reviewed and the following actions were proposed: 1) ....2) Confirm need for leak-befor-brake (LBB) analyses, and 3) ....” Specifically, please provide the link between the review of Information Notice 98-11 and the conclusion of proposed need for LBB analyses.

Response: This RAI is withdrawn, because it was covered by another RAI.

B.4.6 Non-EQ Cables and Connections

B.4.6 -D1 In the LRA, the applicant stated that “the Non-EQ Insulated Cables and Connections Program is credited for aging management of cables and connections not included in the RNP EQ Program.” It is not clear to the staff how the aging of the Electrical/I&C penetration assemblies are managed by this program, since the scope of the program does not include the penetration assemblies.

Response: Note 1.

B.4.6-D2 In the LRA, the applicant stated that the sample locations will consider the location of PVC cables inside and outside containment as well as any known adverse localized environments. It is not clear to the staff that the sample will include other types of cables that may be located in adverse localized environments.

Response: Note 1.

B.4.6-D3 In the RLA, the applicant stated that the scope of Program for the Non-EQ Insulated cables and Connections Program will also be applied to instrument cable insulation, as addressed in Section XI.E2 of the GALL Report; however, the calibration of instrument circuits for the purpose of detecting insulation degradation, as called for in Section XI.E2, is not part of the RNP program. The staff's position on this issue is, a reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument loop. Please refer to RAI 3.6.1-D2 for details. Please clarify this issue.

Response: Note 1.