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December 5, 2008

L-PI-08-098
10 CFR 54

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

Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

Responses to NRC Requests for Additional Information Dated November 5, 2008 Regarding Application for Renewed Operating Licenses

By letter dated April 11, 2008, Northern States Power Company, a Minnesota Corporation, (NSPM) submitted an Application for Renewed Operating Licenses (LRA) for the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. In a letter dated November 5, 2008, the NRC transmitted Requests for Additional Information (RAIs) regarding that application. This letter provides responses to those RAIs.

Enclosure 1 provides the text of each RAI followed by the NSPM response. Enclosure 2 provides additional line items for LRA Table 3.3.2-11 in response to RAI 2.1-2. Enclosure 3 provides sketches to be used in conjunction with the text of the response to RAI AMP-B2.1.38-2.

If there are any questions or if additional information is needed, please contact Mr. Eugene Eckholt, License Renewal Project Manager.

Summary of Commitments

This letter revises two preliminary commitments previously submitted in the LRA transmittal letter dated April 11, 2008. These commitments are subject to NRC acceptance in the Safety Evaluation Report for renewal of the operating licenses.

Revised Commitment Number 12 reads as follows:

> The Fire Protection Program will be enhanced to require periodic visual inspection of the fire barrier walls, ceilings, and floors to be performed during walkdowns at least once every refueling cycle.

1717 Wakonade Drive East • Welch, Minnesota 55089-9642
Telephone: 651.388.1121

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Revised Commitment Number 32 reads as follows:

The Water Chemistry Program will be enhanced as follows:

- The program will require increased sampling to be performed as needed to confirm the effectiveness of corrective actions taken to address an abnormal chemistry condition.
- The program will require Reactor Coolant System dissolved oxygen Action Level limits to be consistent with the limits established in the EPRI PWR Primary Water Chemistry Guidelines.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on December 5, 2008.

Michael D. Wadley
Site Vice President, Prairie Island Nuclear Generating Plant Units 1 and 2
Northern States Power Company - Minnesota

Enclosures (3)

cc:

Administrator, Region III, USNRC
License Renewal Project Manager, Prairie Island, USNRC
Resident Inspector, Prairie Island, USNRC
Prairie Island Indian Community ATTN: Phil Mahowald
Minnesota Department of Commerce

Attachment 1
NSPM Responses to NRC Requests for Additional Information
Dated November 5, 2008

RAI 2.1-1

Title 10 of the *Code of Federal Regulations* (10 CFR) Section 54.4(a)(1) requires that safety-related systems, structures, and components (SSCs) required to be within the scope of license renewal are those which are relied upon to remain functional during and following design basis events to ensure (i) the integrity of the reactor coolant pressure boundary; (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11. During the NRC scoping and screening methodology audit, performed August 4-7, 2008, the applicant stated that there were plant defined safety-related components which were not included within the scope for license renewal in accordance with 10 CFR 54.4(a)(1).

(A) During the audit, the applicant stated that although the waste gas decay tanks were defined as safety related per the plant's definition, they were not in scope for license renewal because they did not meet the above criteria (i), (ii), or (iii). Specifically for criteria (iii), the applicant stated that the plant's criteria for safety-related SSCs was more conservative than the license renewal criteria because the Prairie Island Nuclear Generating Plant has committed to the more conservative 1% of the 10 CFR 100.11 exposure guidelines following a design basis accident. The applicant also documented that the term "comparable" in criteria (iii) has been defined by the nuclear industry as greater than or equal to 10% and the value is consistent with NRC guidance in Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants."

The staff requests that the applicant provide: (1) specific documentation, references, and citations that define the term "comparable," as used in 10 CFR 54.4(a)(1)(iii), to be greater than or equal to 10% and (2) a description of the methods used and the basis for conclusions, in determining that the safety-related waste gas decay tanks would not be included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1).

(B) During the audit, the applicant stated that the boric acid storage tanks were defined as safety-related per the plant's definition, but were not within the scope of license renewal for 10 CFR 54.4(a)(1). The staff requests the applicant provide a description of the methods used and the basis for conclusions, in determining that the safety-related boric acid storage tanks would not be included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1).

NSPM Response to RAI 2.1-1

Part (A)

The term "comparable" in 10 CFR 54.4(a)(1)(iii) is not defined within the License Renewal Rule, Statements of Consideration or Industry License Renewal Guidance documents. While this language is not specific, it is reasonable and logical to interpret the words, "... exposures comparable to those referred to in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11" as meaning "... exposures which approach the dose reference values (limits) defined in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11."

The Standard Review Plan for Review of Safety Analysis Reports for Nuclear Power Plants (NUREG-0800), Section 15.0.3, states that the radiological consequences of design basis accidents and transients should "not exceed", be "well within," or be a "small fraction" of the exposure guidelines of 10 CFR 100.11 (also see NUREG-0800 Sections 15.3.3-15.3.4, 15.6.3 and BTP 11-5). This NRC guidance defines "not exceed" to mean less than or equal to 100% of 10 CFR 100.11 guideline exposures, "well within" to mean less than 25% of 10 CFR 100.11 guideline exposures, and the term "small fraction of" to mean less than 10% of 10 CFR 100.11 guideline exposures.

ANS-58.14, Safety and Pressure Integrity Classification Criteria for Light Water Reactors, Section 5.3.1.4, defines "comparable" as greater than or equal to 10% of 10 CFR 100.11 guideline exposures. This value is chosen because: (1) it is consistent with NUREG-0800 (i.e. "not exceed" and "well within" are "comparable"; however, "small fraction" is not "comparable"); (2) philosophically, being within an order of magnitude is comparable while more than an order of magnitude is not; and (3) it yields results consistent with past and current industry and NRC practice. The standard goes on to state, "This amplification of the safety-related definition recognizes that there must be a threshold value for off-site exposures that defines the boundary between safety-related and non-safety related."

The waste gas decay tanks are designated as Safety Related based on PINGP-unique criteria of 1% of 10 CFR 100 limits contained in the PINGP USAR and plant procedures. NEI 95-10 acknowledges that some components may be designated as Safety Related, but not meet the definition of the Rule. Section 3.1.1 states:

> "It is conceivable that, because of plant unique considerations and preferences, applicants may have previously elected to designate some systems, structures and components as safety related that do not perform any of the requirements of 54.4(a)(1). Therefore, a system, structure or component may not meet the requirements of 54.4(a)(1) although it is designated as safety related for plant-specific reasons."

As shown in USAR 14.5.3.2, a rupture of a waste gas decay tank does not result in offsite exposures comparable (i.e. greater than or equal to 10%) to those referred to in 10 CFR 100 and therefore the tanks are not within the scope of License Renewal for 10 CFR 54.4(a)(1).

Part (B)

The boric acid storage tanks are designated as Safety Related based on plant preference. NEI 95-10 acknowledges that some components may be designated as Safety Related, but not meet the definition of the Rule. Section 3.1.1 states:

"It is conceivable that, because of plant unique considerations and preferences, applicants may have previously elected to designate some systems, structures and components as safety related that do not perform any of the requirements of 54.4(a)(1). Therefore, a system, structure or component may not meet the requirements of 54.4(a)(1) although it is designated as safety related for plant-specific reasons."

License Amendments 156/147 dated April 16, 2001 removed the boric acid storage tanks (BASTs) from the Technical Specifications for the Safety Injection System because the high concentration boric acid in the BASTs is unnecessary for accident mitigation. Therefore, the BASTs are not required to accomplish the functions described in 54(a)(1) and are not within the scope of License Renewal for 10 CFR 54.4(a)(1). The tanks are included within the scope of License Renewal for 10 CFR 54.4(a)(2).

RAI 2.1-2

10 CFR 54.4(a)(2) requires that all nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i-iii) be included within the scope of license renewal. During the NRC scoping and screening methodology audit, performed August 4-7, 2008, the applicant stated that there were certain nonsafety-related abandoned equipment which were not included within the scope for license renewal in accordance with 10 CFR 54.4(a)(2).

(A) LRA Section 2.1.2.5.5 states, "Abandoned equipment that is removed from the plant or disconnected and drained does not have a potential for spatial interaction (i.e. no fluids contained in the SSC), and is not within the scope of License Renewal. Abandoned equipment that is installed and connected to plant process pipes needs to be evaluated for non-safety attached to safety and non-safety affecting safety spatial interaction scoping criteria."

During the scoping and screening methodology audit, the applicant stated that not all abandoned equipment had been verified as disconnected and drained. However, this abandoned equipment had not been included within the scope of license renewal. The staff requests the applicant provide a description of the methods used and the basis for conclusions, in determining that nonsafety-related abandoned systems and attached piping, which had not been verified as disconnected and drained, were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

NSPM Response to RAI 2.1-2

Field walkdowns determined that an abandoned instrument air dryer and its interconnected piping and valves (not shown on the LR Boundary Drawings) are disconnected from the Instrument Air system. The Instrument Air System is not a fluid containing system, so the disconnected components do not have a potential for spatial interaction and are not within the scope of License Renewal.

Field walkdowns along with P&ID and work history reviews determined that #121 Caustic Storage Tank and its interconnected piping and valve, shown on Drawing LR-39241-3 at location B-2, are disconnected and drained, and therefore, do not have a potential for spatial interaction and are not within the scope of License Renewal.

Field walkdowns along with P&ID, work history and isometric drawing reviews determined that #121 Demin Head Tank and its interconnected piping and valves, shown on LR-39241-1 at location D-9, are disconnected from the process pipe and drained. However, the overflow drain to the river (recycle canal) is not disconnected. The overflow drain to the river joins a common drain line below grade. Plugging and potential backfill of the #121 Demin Head Tank overflow line from this common drain line is event driven and not age related. Therefore, the #121 Demin Head Tank and its interconnected piping and valves do not have a potential for spatial interaction and are not within the scope of License Renewal.

Review of P&ID, isometric and physical drawings determined that the Steam Generator Blowdown Hold-Up Tank Filter #11 (Drawing LR-88740, location G-9) and #21 (Drawing LR-39250, location F-5) are disconnected from the process pipe. However the drain lines, at valve BD-12-3 and BD-12-4, respectively, are still connected to the Waste Disposal (WD) System aerated drains. (Note: Drawing LR-39250, location F-5, incorrectly shows this drain line as capped at valve BD-12-4.) Due to the system configuration, complete draining of the piping and components could not be verified, and therefore, these components are brought into the scope of License Renewal based on the criteria of 10 CFR 54.4(a)(2). The SGB Hold-Up Tank Filters and their interconnected piping and valves are connected to and evaluated with the WD System. Addition of these components does not result in any changes to the LRA.

Field walkdowns along with P&ID and physical drawing reviews determined that the Reactor Building Heating components (Drawing LR-39605-1, locations C-7 and B-9) are disconnected. Due to the system configuration, complete draining of the piping and components could not be verified. Therefore, these components are brought into the scope of License Renewal based on the criteria of 10 CFR 54.4(a)(2). The following changes are hereby made to the LRA:

In LRA Section 3.3.2.1.11, Heating System, on LRA Page 3.3-20, the following bullets are added to the list of Environments:

- Raw Water (Internal)
- Primary Containment Air (External)

In LRA Section 3.3.2.1.11, Heating System, on LRA Page 3.3-20, the following bullet is added to the list of Aging Effects Requiring Management:

- Loss of Material - MIC

In LRA Section 3.3.2.1.11, Heating System, on LRA Page 3.3-20, the following bullet is added to the list of Aging Management Programs:

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program

By bringing the additional Heating System piping and components into the scope of License Renewal, as discussed in this RAI response, conforming changes are required in LRA Table 3.3.2-11. The additional table line items that have been incorporated to reflect the added piping and components are provided in Enclosure 2 to this letter.

RAI 2.2-01

Background:

Updated Final Safety Analysis Report (UFSAR) Section 1.3.9, Engineered Safety Features, 1.3.9.f.2 states in part:

The Shield Building Special Ventilation System provides pressure control in the annulus between the Containment Vessel and the Shield Building, and recirculation of annulus air through particulate, absolute and charcoal filters during accident conditions.

License Renewal Application (LRA) Section 2.3.3.6, Cooling Water System Code CL-02 states:

Cooling water supplies wash water to the safeguards traveling screens in the emergency pump bay and the water to the Fire Protection Deluge System installed in each filter assembly in the Shield Building and Auxiliary Building Special Ventilations sub-systems.

Issue:

The Shield Building Ventilation System is addressed in LRA Section 2.3.3.14, Primary Containment Ventilation System, however, the Shield Building **Special** Ventilation System cannot be found in the LRA.

Request:

1. Clarify that the Shield Building Special Ventilation System of LRA Section 2.3.3.6 and UFSAR Section 1.3.9 is the same system as LRA Section 2.3.3.14, Shield Building Ventilation sub-system, or
2. Provide the reasoning for not including the Shield Building Special Ventilation System in Table 2.2-1, Plant Level Scoping Results.

NSPM Response to RAI 2.2-01

The LRA Section 2.3.3.6 and USAR Section 1.3.9.f.2, Shield Building Special Ventilation System, is the same system as LRA Section 2.3.3.14, Shield Building Ventilation sub-system. For License Renewal activities, plant systems were consolidated into License Renewal systems based on related functions or function dependencies. The Shield Building Ventilation sub-system is evaluated with the Primary Containment Ventilation System. Scoping results are presented in Table 2.2-1, Plant Level Scoping Results, and LRA Section 2.3.3.14, Primary Containment Ventilation System. Results of scoping are also documented on License Renewal Boundary drawings LR-39602-1 (grid coordinate H3) and LR-39602-2 (grid coordinate H3).

RAI 2.2-02

Background:

UFSAR Table 12.2-1, Classification of Structures, Systems and Components, classifies the Chemical Lab and Counting Room Ventilation System as Class III.

LRA Section 2.3.3.19 states in part:

The ZB System includes the Turbine Building, Old Admin Building, New Admin Building, Cold Chemical Lab, and TSC Ventilation and Cleanup sub-systems.

Issue:

The Chemical Lab and Counting Room Ventilation System identified in UFSAR Table 12.2-1 cannot be found in the LRA.

Request:

1. Clarify that the Cold Chemical Lab of LRA Section 2.3.3.19 is the same system as UFSAR Table 12.2-1 Chemical Lab and Counting Room Ventilation System, or
2. Provide the reasoning for not including the Chemical Lab and Counting Room Ventilation System in Table 2.2-1, Plant Level Scoping Results.

NSPM Response to RAI 2.2-02

The USAR Table 12.2-1 Chemical Lab and Counting Room Ventilation System is the same system as LRA Section 2.3.3.1, Hot Lab/Sample Room Ventilation sub-system. For License Renewal activities, plant systems were consolidated into License Renewal systems based on related functions or function dependencies. Two laboratory facilities are available at the plant. One laboratory facility is located in the Auxiliary Building for "hot" chemistry work. This facility includes the radiochemistry laboratory, sample room and counting room. The Hot Lab/Sample Room Ventilation sub-system is evaluated in

LRA Section 2.3.3.1, Auxiliary and Radwaste Area Ventilation System, and shown on License Renewal Boundary drawing LR-39600 (grid coordinate D5). The other laboratory facility is located in the Turbine Building for "cold" chemistry work. The Cold Chemical Lab Ventilation sub-system is evaluated in LRA Section 2.3.3.19, Turbine and Administration Building Ventilation System, and shown on License Renewal Boundary drawing LR-39601 (grid coordinate G5). Scoping results are presented in Table 2.2-1, Plant Level Scoping Results, LRA Section 2.3.3.1, Auxiliary and Radwaste Area Ventilation System, and LRA Section 2.3.3.19, Turbine and Administration Building Ventilation System. Results of scoping are also documented on License Renewal Boundary drawings LR-39600 and LR-39601.

RAI 2.2-03

Background:

UFSAR Table 12.2-1, Classification of Structures, Systems and Components, classifies the Generator Cooling Water System as Class III.

Issue:

The Generator Cooling Water System could not be located in Table 2.2-1, Plant Level Scoping Results.

Request:

Provide the reasoning for not including the Generator Cooling Water system in Table 2.2-1, Plant Level Scoping Results.

NSPM Response to RAI 2.2-03

USAR Table 12.2-1 Generator Cooling Water System is evaluated as part of the LRA Section 2.3.4.8, Turbine Generator and Support (TB) System, and LRA Section 2.3.3.6, Cooling Water (CL) System. For License Renewal activities, plant systems were consolidated into License Renewal systems based on related functions or function dependencies. The USAR Table 12.2-1 Generator Cooling Water System generator hydrogen coolers are the same as the hydrogen cooling turbine auxiliary equipment described in LRA Section 2.3.4.8 and shown on License Renewal Boundary drawings LR-39216-2 (grid coordinate E3) and LR-39217-1 (grid coordinate G8). The USAR Table 12.2-1 Generator Cooling Water System water supply is the same as the water supply to the TB system described in LRA Section 2.3.3.6, Cooling Water System, Function CL-06: "Cooling water provides heat removal for the SA, SB and TB Systems," and shown on drawings LR-39216-2 (grid coordinate E3) and LR-39217-1 (grid coordinate G8). Scoping results are presented in Table 2.2-1, Plant Level Scoping Results, LRA Section 2.3.4.8, Turbine Generator and Support System, and LRA Section 2.3.3.6, Cooling Water System. Results of scoping are also documented on License Renewal Boundary drawings LR-39216-2 and LR-39217-1.

RAI 2.2-04

Background:

UFSAR Table 12.2-1, Classification of Structures, Systems and Components, classifies the Reactor Gap Cooling, Reactor Refueling Cavity Ventilation and Reactor Support Cooling Systems as Class II.
Issue:

The Reactor Gap Cooling, Reactor Refueling Cavity Ventilation or Reactor Support Cooling Systems could not be located in Table 2.2-1, Plant Level Scoping Results.

Request:

Provide the reasoning for not including the Reactor Gap Cooling, Reactor Refueling Cavity Ventilation and Reactor Support Cooling Systems in Table 2.2-1, Plant Level Scoping Results.

NSPM Response to RAI 2.2-04

USAR Table 12.2-1 Reactor Gap Cooling and Reactor Support Cooling Systems are the same systems as LRA Section 2.3.3.14, Reactor Cavity Cooling and Reactor Vessel Support Pad Cooling sub-systems respectively. USAR Table 12.2-1 Reactor Refueling Cavity Ventilation System is no longer installed and therefore does not need to be included in the PINGP LRA. For License Renewal activities, plant systems were consolidated into License Renewal systems based on related functions or function dependencies. As described in USAR 5.2.2.3.1.4, the Reactor Cavity Cooling sub-system provides air flow to the reactor vessel gap and the neutron detector wells and is evaluated in LRA Section 2.3.3.14, Primary Containment Ventilation System, and shown on License Renewal Boundary drawings LR-39602-1 (grid coordinate G8) and LR-39602-2 (grid coordinate G7). The Reactor Vessel Support Pad Cooling is described in USAR 5.2.2.3.1.3 and is evaluated in the LRA Section 2.3.3.14, Primary Containment Ventilation System, and shown on License Renewal boundary drawings LR-39602-1 (grid coordinate F8) and LR-39602-2 (grid coordinate F7). Scoping results are presented in Table 2.2-1, Plant Level Scoping Results, and LRA Section 2.3.3.14, Primary Containment Ventilation System. Results of scoping are also documented on License Renewal Boundary drawings LR-39602-1 and LR-39602-2.

RAI 2.2-05

Background:

1. UFSAR 4.4.2.4, Acoustic Monitoring System states in part:

   The acoustic monitoring system indicates the position of the pressurizer safety valves and the PORVs. It provides a rapid means of detecting flow through the *safety valves and the PORVs. The acoustic monitors are installed on the common discharge of the safety valves and the inlets for each PORV.*

2. UFSAR 7.9.3, Seismic Monitoring System, states in part:

   The Seismic Monitoring System was installed in response to AEC questions during original plant licensing. These commitments also stated that the central seismic monitoring and recording system would be installed in accordance with Safety Guide 12 (Reference 58). The purpose of this QA type 3 system is to monitor and record seismic events and to determine the peak seismic accelerations of critical plant piping systems during a seismic event.

Issue:

The Acoustic Monitoring and Seismic Monitoring Systems could not be located in Table 2.2-1, Plant Level Scoping Results.

Request:

Provide the reasoning for not including the Acoustic Monitoring and Seismic Monitoring Systems in Table 2.2-1, Plant Level Scoping Results.

NSPM Response to RAI 2.2-05

The USAR Section 4.4.2.4 Acoustic Monitoring System components were initially included in the Electrical Event Monitoring system. USAR Section 7.9.3 Seismic Monitoring System components were initially included in the Electrical Miscellaneous Plant Instruments system. Components within these systems were then grouped into electrical and I&C commodities. Since components in the electrical and I&C systems are encompassed by the commodity groups, no system level intended functions were identified in the LRA. The Event Monitoring and Miscellaneous Plant Instruments system scoping results are presented in Table 2.2-1, Plant Level Scoping Results.

RAI B2.1.1-1

During the AMP audit, the staff reviewed historic test data for the Unit 2 maintenance airlock, which failed a Type B test in 1989. During this review, the staff found that the Type B & C allowable leak rates were changed from 154,800 to 43,331 cc/min on the provided surveillance procedures since 1998. The staff also noticed relatively high leak rates through the maintenance airlock prior to 2002.

The staff requests that the applicant provide an explanation and basis for the above two changes in order to provide sufficient information relative to operating experience for the Appendix J AMP.

NSPM Response to RAI B2.1.1-1

Response to Type B & C Allowable Leak Rates

The change in the Type B/C allowable leak rate from 154,800 cc/min to 43,331 cc/min was the result of an evaluation documented in LER 1-98-02, "Control Room Unfiltered Air Inleakage Found to be Excessive," submitted to the NRC on February 18, 1998. The LER event description is summarized as follows:

During Control Room envelope testing, the preliminary result for the total in-leakage into the Control Room was measured to be 380 cfm and later recalculated to be 282 cfm. This was higher than the design input of 165 cfm used in the post-Loss-of-Coolant-Accident (LOCA) and Main Steam Line Break (MSLB) (outside of containment) control room personnel dose analyses.

Based upon dose evaluations for the MSLB and LOCA accidents, the control room ventilation system was determined to be operable. The dose evaluations predicted control room operator doses being within the GDC 19 (10CFR50 Appendix A) criteria. The LOCA control room dose operability evaluation had been based upon a lower containment leakage rate than allowed by Technical Specifications. The lower containment leakage rate was based upon the measured containment leakage rate, plus the maximum allowable airlock leakage rate, plus margin. The MSLB control room dose operability evaluation was based upon predicted end of cycle steam generator tube leakage.

In response to LER 1-98-02, the Control Room door seals were repaired/ replaced, and the Control Room envelope was tested and retested until in-leakage was acceptable. In addition, the plant maintenance procedure for maintaining the Control Room envelope door seals was improved to reduce the potential for in-leakage.

In 2000, following repairs to the Control Room doors and ventilation dampers, gas tracer testing confirmed that Control Room in-leakage had been reduced to acceptable levels. Following this testing, acceptance criteria were restored to the original 154,800 cc/min value.

Response to Maintenance Air Lock Leak Rates

The relatively high leak rates through the maintenance airlock prior to 2002 were primarily due to leakage through the penetration seal assemblies of the hand wheel shafts used for operating the doors from outside of the airlock. A new airlock door shaft seal design was approved by the Prairie Island modification process and installed in the maintenance airlock hand wheel shaft penetration assemblies for both Units in December 2000.

Prior to this modification, the seal configuration consisted of either mechanical seals or a packing arrangement. The mechanical seals were not very tolerant of shaft misalignment. Misaligned shafts placed an abnormal load on the shaft seals causing them to wear which resulted in the leakage. The packing arrangement was more tolerant of misalignment. However, the packing arrangement did contribute to a number of failures due to cramped working conditions that prevented adequate inspection and maintenance of the packing. The modified seal configuration utilizes O-rings. The design of this configuration allows for a greater amount of misalignment and does not require routine maintenance in order to maintain a tight seal.

RAI AMP-B2.1.2-1:

NUREG–1801, "Generic Aging Lessons Learned (GALL) Report" AMP XI.M29, "Aboveground Steel Tanks," recommends that based on operating experience, plant system walkdowns each outage will provide for timely detection of aging effects. However, the staff noted from the applicant's program basis document that external visual inspections will be performed at least once per refueling cycle and inspection scope/frequency will be adjusted based on the results of the previous inspections and operating experience. The applicant further states that sample selections of insulation near the bottom of each insulated tank will be removed periodically to directly examine the tank exterior. The staff noted that the frequency of inspections for the tank bottoms and exterior tank surfaces of insulated tanks were not specified.

- Clarify the inspection frequency for the inaccessible surfaces (tank bottoms) of the tanks in the scope of this program.
- Clarify the inspection frequency for the tank exterior of the insulated tanks that require the periodic removal of the insulation near the bottom of the tanks.
- Clarify and justify the number of inspections that will be performed on the external (accessible) surfaces, the inaccessible surfaces (tank bottoms), and the tank exteriors that require removal of insulation in scope of this program, before the inspection scope/frequency will be adjusted.

NSPM Response to RAI AMP-B2.1.2-1

The Aboveground Steel Tanks Program will perform at least one ultrasonic inspection of the inaccessible surfaces (tank bottoms) of one of the three Condensate Storage Tanks (CSTs) to ensure that significant degradation is not occurring due to corrosion of the external surfaces. The inspection will be performed within the 10-year period just prior to the period of extended operation to ensure the component intended function will be maintained during the renewal term. Any indications or relevant conditions of degradation detected will be evaluated and compared to predetermined limits such as design minimum tank wall thickness and corrosion allowance. Inspection results will be evaluated to determine if additional inspections are needed to assure that the extent of wall thinning is adequately determined. Additional inspections may be conducted as necessary based on plant-specific inspection results and industry operating experience.

The CSTs are located outdoors and are insulated. All three CSTs are fabricated from the same material and experience the same environment; consequently the aging effects for one tank would be representative of the aging effects for all three tanks. A search of the PINGP corrective action program documents over the past five years revealed instances of minor corrosion (surface rust) and coating degradation (hatch covers) on the external surfaces of the CSTs. The corrosion was documented and determined to be within the design corrosion allowance of the tanks.

For the insulated CSTs, a visual inspection of the entire exterior surface of the insulation will be performed at least once per refueling cycle. The inspection will look for damage to insulation or its outer covering that could permit water ingress, and for discoloration or other evidence that the insulation has been wetted. If insulation damage or wetting is identified, insulation will be removed at the affected location to permit direct inspection of the external tank surface. In addition, sample sections of insulation near the bottom of each insulated outdoor tank (i.e., locations with the highest potential for wetted insulation) will be removed periodically to permit direct inspection of the tank exterior. Removal of insulation to facilitate visual inspection of the insulated external portions of one of the three CSTs will be performed once per refueling cycle. Any degradation of carbon steel tank external surfaces will be recorded and evaluated to ensure the component intended function will be maintained. Inspection results will be evaluated to determine if additional direct visual inspections are needed to assure that the extent of corrosion is adequately determined.

The intervals of inspections may be adjusted as necessary based on plant-specific inspection results and industry operating experience. The tanks will be inspected at intervals that provide reasonable assurance that loss of material due to corrosion will be managed such that these components will continue to perform their intended function during the period of extended operation. If corrosion is occurring, the condition will be entered into the Corrective Action Program for evaluation to determine acceptability of the affected components for further service, adequacy of the frequency of the inspection interval, and assessment of required corrective actions.

The three CSTs are the only tanks included in the scope of the Aboveground Steel Tanks Program. The two precoat slurry tanks previously included in this aging management program have since been removed from the scope of License Renewal since these tanks are normally dry and only used during refueling outages. The precoat slurry tanks do not meet the criteria listed in 10 CFR 54.4(a)(1), (2) or (3).

To reflect the removal of the precoat slurry tanks from scope, the PINGP LRA is hereby revised as follows:

In Table 3.4.1, line item 3.4.1-28 on Page 3.4-29, reference to the Aboveground Steel Tanks Program is deleted from the Discussion field. The revised line item then appears as follows:

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-28	Steel external surfaces exposed to air –indoor uncontrolled (external), condensation (external), or air outdoor (external)	Loss of material due to general corrosion	External Surfaces Monitoring	No	Consistent with NUREG-1801. This aging effect is managed with the External Surfaces Monitoring Program.

In Table 3.4.2-4, on Page 3.4-83, in the line item for "Tanks", "Pressure Boundary", "Carbon Steel", "Plant Indoor Air - Uncontrolled (Ext)", "Loss of Material - General Corrosion", the partial row containing "Aboveground Steel Tanks Program", "VIII.H-7", "3.4.1-28", and "E" is deleted. The revised Tanks line item from Page 3.4-83 then appears as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon Steel	Outdoor Air - Sheltered (Ext)	Loss of Material - General Corrosion	Aboveground Steel Tanks Program	VIII.E-39	3.4.1-20	A
			Plant Indoor Air - Uncontrolled (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VIII.H-7	3.4.1-28	A
			Treated Water (Int)	Loss of Material - Crevice Corrosion	One-Time Inspection Program	VIII.E-40	3.4.1-06	A
					Water Chemistry Program	VIII.E-40	3.4.1-06	B
				Loss of Material - Galvanic Corrosion	One-Time Inspection Program	VIII.E-40	3.4.1-06	A, 410
					Water Chemistry Program	VIII.E-40	3.4.1-06	B, 410
				Loss of Material - General Corrosion	One-Time Inspection Program	VIII.E-40	3.4.1-06	A
					Water Chemistry Program	VIII.E-40	3.4.1-06	B

RAI B2.1.4-1

In the PINGP LRA, the IWE AMP discusses coating degradation under "Operating Experience" but the LRA does not address aging management of coatings. The failure of coatings could result in aging effects for the steel containment vessel. The failure of coatings could also result in the failure of safety systems to perform their intended functions (for instance, safety injection).

The staff requests that the applicant provide a basis for not having an aging management program for coatings, including a discussion of plant specific operating experience related to coating inspection and degradation.

NSPM Response to RAI B2.1.4-1

The Containment Inservice Inspection Program (ASME Section XI, Subsection IWE Program) and the Containment Leak Rate Program (10 CFR Part 50, Appendix J Program) are credited with managing the aging effect loss of material due to corrosion for the containment vessel. These programs look for evidence of corrosion and utilize the condition of the coated surface as a means to evaluate the condition of the underlying base metal. The Programs look for evidence of flaking, blistering, peeling, discoloration, corrosion, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement. Coatings inside containment provide protection for the underlying base metal but are not relied upon to mitigate any aging effect and, therefore, perform no License Renewal intended function as defined in 10 CFR 54.4(a)(1), (2) and (3).

With respect to the failure of coatings that could result in the failure of safety systems to perform their intended functions, PINGP has performed an analysis of the susceptibility of the ECCS and CSS recirculation functions to the adverse effects of post-accident debris blockage and operation with debris-laden fluids in response to Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during DBA at Pressurized-Water Reactors." The analysis demonstrated that debris will not prevent a safety related component from performing its intended function. It assumes that all qualified coatings within the zone of influence of the worst case pipe break fail, and all unqualified coatings inside containment fail and become debris along with other debris that could be generated by a pipe break. Degraded qualified coatings are considered unqualified coatings under the baseline methodology approved by the NRC. As part of the response to Generic Letter 2004-02, containment walkdowns were performed to quantify the potential debris sources. PINGP has implemented activities that perform inspections and assessment of the condition of coatings inside containment to confirm that the potential volume of debris would remain conservatively low. These activities do not prevent coating failures, and are used only to minimize debris that could be generated during a LOCA.

In summary, the PINGP analysis that is part of the CLB assumes that coatings fail, assumes that degradation of qualified coatings occurs, and demonstrates that such failed coatings (along with other debris that would be generated by a pipe break) would not prevent a safety related component from performing its safety function (i.e., failed coatings would not cause strainer blockage). Therefore, coatings inside containment do not fall within the scope of 10 CFR 54.4(a)(2) since they are not components whose failure could prevent satisfactory accomplishment of safety functions, and are not credited with any intended function that must be maintained under the License Renewal Rule.

Examples of plant operating experience for containment vessel coatings are provided below. Plant procedures are used to provide guidance on the inspection and assessment of the condition of the coatings inside containment. Quantities of unqualified and degraded coatings, determined to be potential debris sources contributing to plugging of the sump recirculation screens, are calculated and evaluated using the established acceptance criteria to confirm that the volume of debris calculated remains conservatively low and would not cause sump screen blockage. Results of the inspection are compiled in the plant's "Containment Coatings Assessment Report" and the "Unqualified and Degraded Coatings Log."

Examples of degraded coatings identified during the Unit 1 coatings inspections in May of 2006 include:

- Flaking and chipping near the drain at the 695 elevation in zone B over an area of 4 sq ft, and a thickness of 0.028 inches, and
- Flaking and chipping inside the Regenerative Heat Exchanger Room at elevation 695 over an area of 5 sq ft, and a thickness of 0.028 inches.

Examples of degraded coatings identified during the Unit 2 coatings inspections in November of 2006 include:

- Flaking on grating below RCS piping in the RCP/SG vault lower level over an area of 6 sq ft, and a thickness of 0.007 inches, and
- Delamination/chipping on the ladder to lower RCP/SG vault of an insignificant area, and a thickness of 0.007 inches.

Examples of degraded coatings identified during the Unit 1 coatings inspections in February of 2008 include:

- Cracking on the Sump B platform at elevation 695 of zone A over an area of 0.5 sq ft, and a thickness of 0.028 inches, and
- Flaking on a hanger support at elevation 695 of zone B over an area of 1 sq ft, and a thickness of 0.007 inches

For the above three examples of degraded coatings inspection findings, corrective action was taken to remove the identified degraded coatings, and for those areas where the degraded coatings were not removed, an evaluation was performed to review the amount of unqualified coatings to ensure that the volume of debris left in containment was less than the calculated limit.

RAI B2.1.6-1

The PINGP LRA AMP B.2.1.6, "Bolting Integrity Program," is not clear in how it satisfies the GALL report program element "Monitoring and Trending". Specifically, the element requires bolting connections for pressure retaining components (not covered by ASME Section XI) to be "...inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly." PINGP credits the corrective action program for meeting this inspection frequency: however, the staff could not determine how this is achieved. In addition, if this recommendation was not specifically addressed in written procedures and guidance, there was no exception documented.

The staff requests that the applicant provide detailed plans for inspection frequency which satisfy this GALL element or the basis for taking an exception.

NSPM Response to RAI B2.1.6-1

Bolted connections with identified leakage are evaluated through the site Corrective Action Program (CAP). Each new CAP Action Request that affects plant equipment is reviewed by a Senior Reactor Operator (SRO) who assigns immediate actions or compensatory actions, as appropriate. These actions may include removing the equipment from service or frequent periodic monitoring, among others. Bolted connections which are experiencing leakage are nominally subject to daily or shiftly checks, such as those performed during normal operations walkdowns of the plant, and potentially other actions, depending upon the significance, trend, and ALARA considerations.

If the active leakage is borated water, an evaluation is also performed under the Boric Acid Corrosion Program. This evaluation assesses the size, location and potential significance of the leak (e.g., leak rate, ASME or non-ASME components affected, inside or outside containment), the expected future progression of the leak, and the corrosion potential of the leak on materials contacted (e.g., contact with carbon steel, contact with bolting, etc.). This evaluation determines whether the condition requires immediate repairs or cleaning, or whether repairs may be performed at a later maintenance opportunity (e.g., scheduled outage). The evaluation also determines any monitoring requirements and frequency that should be imposed. Initial inspection frequencies may be further adjusted based on observations (e.g., whether leak rate remains stable) and any corrective actions implemented to reduce or further manage (e.g., contain or reduce) the identified leakage.

In short, the actual assignment of an appropriate monitoring frequency is not an administrative activity, but is based on the specific conditions and significance of each leak, as evaluated through the site Corrective Action Program. All active leaks are monitored on an appropriate frequency.

This approach is consistent with the graded approach recognized in the NUREG-1801, Chapter XI, Program XI.M18, discussion for bolted mechanical joints. Both Element 5 of XI.M18 and Section 4.3 of EPRI TR-104213, "Bolted Joint Maintenance &

Applications Guide" (a NUREG-1801 reference) recognize that an initial monitoring frequency may be decreased if the condition of the leak can safely and reasonably permit. An initial nominal observation frequency of daily or shiftly may be reduced to a weekly, biweekly, or other frequency based on the significance and stability of the observed leakage and whether the leak is active or inactive.

While the PINGP approach is believed to be consistent with the intent of Section 4.3 of EPRI TR-104213, it may be viewed as inconsistent with the specific prescriptive language of the Monitoring and Trending element of NUREG-1801, Program XI.M18. Accordingly, PINGP LRA Section B2.1.6 is hereby revised to add an exception, as follows:

On Page B-22, under "Exceptions to NUREG-1801, Program Elements Affected", a new bullet is hereby added, to read as follows:

- "Monitoring and Trending

  The inspection frequency for bolted connections which have indications of leakage is determined on a case by case basis under the Corrective Action Program, consistent with the specific characteristics and safety significance of each leak. This is an exception to the daily, weekly, and biweekly inspection frequencies recommended in NUREG-1801, XI.M18. When a leak is identified and entered into the Corrective Action Program, it is reviewed by a Senior Reactor Operator (SRO) who assigns immediate or compensatory actions as appropriate. These actions can include taking the equipment out of service or frequent periodic monitoring, among others. Bolted connections which are experiencing leakage are nominally subject to daily or shiftly checks, such as those performed during normal operations walkdowns of the plant, and potentially other actions, depending upon the significance, trend, and ALARA considerations. Evaluations performed through the Corrective Action Program ensure that all active leaks are monitored on an appropriate frequency. Initial inspection frequencies may be adjusted based on observations and actions taken (e.g.; leak stability, leak reduction, containment of leakage). This approach is consistent with the graded approach implicit in the NUREG-1801 discussion and in Section 4.3 of EPRI TR-104213."

RAI B2.1.6-2

In the PINGP LRA, AMP B.2.1.6, "Bolting Integrity Program," states that it follows the guidance contained in NUREG-1339, EPRI NP-5769, and EPRI TR-104213. These guidance documents are accepted by the GALL XI.M18 Bolting Integrity Program. However, PINGP states that it also follows the guidance contained in other industry based recommendations including EPRI NP-5067, EPRI NP-6316, and EPRI TR-111472, which are not identified as accepted guidance documents in the GALL.

The staff requests that the applicant indicate when the guidance contained in EPRI NP-5067, EPRI NP-6316, and EPRI TR-111472 is used, and whether or not its usage will contradict the GALL approved guidance. In addition, provide an account of any contradictions between the two sets of guidance and their impact on this program.

NSPM Response to RAI B2.1.6-2

EPRI NP-5067 Volume 1 was published in 1987, and Volume 2 in 1990. NP-5067 has served as a primary reference for a series of subsequent documents, including EPRI NP-5769 (1988), NP-6316 (1989), NUREG-1339 (1990), EPRI TR-104213 (1995), and TR-111472 (1999). The following table shows the inter-relationships between the various documents and highlights several points of interest:

Document	Date of Publication	Summary Description	Document References & Citations (partial list)
NP-5067, Volume 1	1987	Practical field reference for large bolts.	Based on various industry & NRC source documents.
NP-5769[1]	April 1988	Technical basis for GSI 29 bolting issue resolution. Discusses in Volume 1 (page 2-8) how NP-5067 satisfies the industry's need for guidance "...for assembly and disassembly, inspection and verification of bolted joint performance."	NP-5067 Vol. 1, 1987 NP-5067 Vol. 2 (Section 2 References state Volume 2 is "To be published as an EPRI Report.")
NP-6316	July 1989	Guidance for selection, specification and installation of threaded fasteners.	NP-5067 Vol. 1, 1987
NUREG-1339[1]	June 1990	Documented NRC's resolution of GSI 29 based on NP-5769. Section 3 (pp. 11-15) includes five technical exceptions or comments regarding NP-5769. None relate to the information provided in NP-5067.	NP-5769, 1988 NP-5067 Vol. 1 & 2
NP-5067, Volume 2	December 1990	Practical field reference for small bolts.	NP-5067 Vol. 1, 1987 NP-5769, 1988 NP-6316, 1989 NUREG-1339, 1990

TR-104213[1]	December 1995	Consolidated NP-5067 and NP-6316 into single updated document.	NP-5067 Vol. 1, 1987 NP-5067 Vol. 2, 1990 NP-6316, 1989 NUREG-1339, 1990
TR-111472	August 1999	Practical field training module for assembling bolted, gasketed connections.	NP-5067, 1987 TR-104213, 1995

[1]Cited in NUREG-1801, Program XI.M18, Bolting Integrity.

As summarized above, the guidance of EPRI NP-5067 was, for all practical purposes, endorsed through NRC's concurrence with NP-5769 as documented in NUREG-1339. NUREG-1339 identifies no specific exceptions to the NP-5067 guidance. Therefore, reference to NP-5067 in PINGP maintenance procedures is considered to be equivalent to a reference to NP-5769 and NUREG-1339[2]. It is also considered equivalent to a reference to later standard EPRI TR-104213, which was issued to consolidate information previously published in EPRI NP-5067, among other references. Therefore, reference to NP-5067 in plant procedures is not an exception to NUREG-1801, Program XI.M18.

EPRI NP-6316 is referenced in the PINGP Engineering Manual for the specification of mechanical fasteners. Review has shown that much of Sections 14 and 15 of TR-104213 is verbatim repetition of Sections 2 and 3 of NP-6316. No substantive technical differences were noted between NP-6316 and Sections 14 and 15 of TR-104213 for fastener selection and specification. Therefore, the procedural reference to NP-6316 is not an exception to the NUREG-1801 citation of TR-104213.

EPRI TR-111472 serves as one basis for the general plant maintenance procedure for installation of threaded fasteners. The EPRI document was issued as a training module

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[2] The NRC has previously concurred with this conclusion. In the SER for WCNOC license renewal, on pages 3-66 and 3-67, the NRC states, "Exception 2. In the LRA, the applicant credited an exception to the GALL Report program elements 'scope of the program,' and 'preventive actions.' Specifically, the exception stated: The procedures for ensuring bolting integrity identify preload requirements and general practices for in-scope bolting but do not directly reference EPRI NP-5769 or NUREG-1339 as applicable source documents for these recommendations. However, these procedures do reference and incorporate the good bolting practices identified in EPRI NP-5067 and EPRI TR-104213. EPRI NP-5769 and NUREG-1339 are very closely related with EPRI NP-5067 and EPRI TR-104213 and they cross-reference one another. EPRI NP-5769, Section 8, Good Bolting Practices, refers to EPRI NP-5067 for the identification of bolting practices associated with disassembly and assembly of bolted joints, and the methods for minimizing bolted joint problems such as leaks, vibration loosening, fatigue, and stress corrosion cracking. <u>Implementation of the recommendations in EPRI NP-5067 and EPRI TR-104213 is considered to be consistent with the recommendations in EPRI NP-5769 and NUREG-1339 to meet the NUREG-1801 recommendations. The staff finds this exception acceptable because the EPRI recommendations followed by the applicant are consistent with the recommendations provided in the GALL Report." [emphasis added]</u>

with a specific focus on bolted connections using spiral-wound gaskets for sealing, and is based on EPRI NP-5067 and EPRI TR-104213. The document restates and summarizes some of the practical guidance in NP-5067 and the theoretical information in TR-104213 in a form that is more usable for maintenance and training. Its purpose, as described on page v, is "to provide mechanics, work planners, engineers, quality control (QC) personnel, and plant management with sufficient theory and practical hands-on training regarding bolted joints with spiral-wound gaskets so that they will have the knowledge to reduce leakage from these joints in a cost-effective manner." Review has shown that there are no substantive technical differences between TR-111472 and NP-5067/TR-104213 for maintenance of bolted joints. Therefore, use of this reference is not an exception to the NUREG-1801 citation of TR-104213.

In summary, a review has confirmed that the use of EPRI documents NP-5067, NP-6316, or TR-111472 as the basis for certain bolting activities in PINGP plant procedures does not contradict the guidance for those activities provided in NUREG-1339, EPRI NP-5769 or EPRI TR-104213 which are cited in NUREG-1801, XI.M18. Therefore, use of these documents does not represent an exception to NUREG-1801.

RAI-B2.1.6-3

In the PINGP LRA, AMP B.2.1.6 "Bolting Integrity Program" identifies an enhancement to the GALL report program elements "Parameters Monitored/Inspected" and "Detection of Aging Effects" regarding enhancement of guidance for visual inspections of installed bolting. However, the LRA does not specify the enhancements in sufficient detail.

The staff requests that the applicant provide clarification on specifically what will be changed. Additionally, provide clarification on how the visual inspections described in the enhancement will meet the inspection specifications set forth in the GALL Report Bolting Integrity Program, and justification if it is not consistent with this GALL Report program.

NSPM Response to RAI B2.1.6-3

The referenced enhancement (also Preliminary License Renewal Commitment No. 4) states: "Procedures for the conduct of inspections in the External Surfaces Monitoring Program, Structures Monitoring Program, Buried Piping and Tanks Inspection Program, and the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced to include guidance for visual inspections of installed bolting."

The PINGP Bolting Integrity Program is supplemented by other aging management programs for the inspection of installed bolting. The purpose of this enhancement is to incorporate specific guidance, consistent with the recommendations of NUREG-1801, XI.M18, for the inservice inspection of those bolted mechanical joints that are inspected under these supplemental programs. The enhancement will ensure that the appropriate inspection guidance is incorporated into the implementing procedures which govern the required bolting inspections.

The enhancement will provide the necessary procedural guidance to monitor the effects of aging on the intended function of closure and structural bolting. The guidance will define the types of conditions indicative of potential degradation which the inspection should identify and document for evaluation. Conditions of interest include evidence of leakage, and evidence of other degradation such as loosening (loss of preload), corrosion (loss of material), or conditions indicative of a corrosive environment that could lead to stress corrosion cracking. This guidance is consistent with the NUREG-1801, XI.M18 inspection guidance for the elements Parameters Monitored/Inspected and Detection of Aging Effects.

RAI B2.1.6-4

In the PINGP LRA, AMP B.2.1.6, "Bolting Integrity Program," identifies the External Surfaces Monitoring Program, Buried Piping and Tanks Inspection Program, Structures Monitoring Program, and RG 1.127 Inspection of Water Control Structures Associated with Nuclear Power Plants Program as other aging management programs which implement aspects of the bolting integrity program. However, these supplemental programs include inconsistent statements in their program basis documents regarding their management of bolting. The discrepancies indicate a possible misunderstanding of the intent of the Bolting Integrity Program. As a result, it is not clear how, or if, these supplemental programs implement the specifications set in the Bolting Integrity Program. Examples of discrepancies are included below:

- The Bolting Integrity Program, Scope of Program Element states in several locations that other supplemental AMPs provide the requirements for the inspection of the applicable bolting for each supplemental program. However, this statement may cause a discrepancy with the GALL Bolting Integrity Program. The Bolting Integrity Program provides the requirements for the supporting AMPs to implement.

- The Structures Monitoring Program and RG 1.127 Inspection of Water Control Structures Associated with Nuclear Power Plants Program states in their Detection of Aging Effects summary that "The program is supplemented by the Bolting Integrity Program..." However, this statement may cause a discrepancy with the GALL Bolting Integrity Program. The Bolting Integrity Program is supplemented by the supporting AMPs.

- The External Surfaces Monitoring Program does not specifically identify bolting as a component that it manages. If the program does not manage bolting, then the statements made in the Bolting Integrity Program are incorrect.

The staff requests that applicant provided the inspection requirements which will enable it to meet the inspection specifications set forth in the GALL Bolting Integrity Program for each AMP that supplements the Bolting Integrity Program. Additionally, ensure that these programs are amended accordingly to accurately portray the correct intent of the programs as highlighted in the examples above.

NSPM Response to RAI B2.1.6-4

Part A

The inspection requirements to be incorporated into the procedures which implement the inspections credited by the Bolting Integrity Program are described in the response to RAI-B2.1.6-3 above. As noted, this guidance is consistent with the NUREG-1801, XI.M18 inspection guidance. It is understood that the Bolting Integrity Program defines the basic inspection requirements for bolting. To assure consistent field implementation of these requirements, however, the procedures actually used for those inspections should contain those requirements, and not rely on references to other documents. As discussed in the enhancement, each procedure used to implement the inspections in the field is intended to be self contained with sufficient guidance for the identification and documentation of potentially degraded conditions. Therefore, the enhancement identified the implementing procedures for the External Surfaces Monitoring Program, Buried Piping and Tanks Inspection Program, Structures Monitoring Program, and RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as needing more explicit guidance for bolting inspection. The implementing procedures associated with bolting inspections under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; ASME Section XI, Subsection IWE Program; and ASME Section XI, Subsection IWF Program were judged not to require enhancement because the inspection schedules and requirements are already sufficiently well defined in ASME Section XI.

Part B

Responses to the three examples are as follows:

We concur that the basic requirements for bolting inspection originate in the Bolting Integrity Program. However, as discussed above, each procedure that is relied on to perform bolting inspections in the field should have sufficient information to identify and document potentially degraded conditions without reference to other documents. Therefore, the inspection requirements that are defined in the Bolting Integrity Program will also be placed in the applicable inspection procedures of other supplemental aging management programs (AMPs) to assure consistent implementation.

The cited statements in the PINGP Program Basis Documents for the Structures Monitoring Program and the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program refer to the Bolting Integrity Program for guidance on bolting material selection, lubricant control, assembly, and torque requirements. These two supplemental AMPs are condition monitoring programs and do not address subjects such as bolting material selection, lubricant control, assembly and torque requirements. The statements do not suggest that these programs supersede or contradict the Bolting Integrity Program. Rather, as discussed above, the visual inspection requirements for bolting will be included in the implementing procedures for these supplemental programs, thereby ensuring consistency with the inspection guidance specified in the PINGP Bolting Integrity Program.

The External Surfaces Monitoring Program does include bolting as an integral part of the installed piping, piping components, ducting, and other components subject to inspection under the program. For clarity, the PINGP LRA is hereby revised as follows:

- In Section A2.14, External Surfaces Monitoring Program (Page A-7), the second sentence is revised to read: "Periodic system inspections and walkdowns are conducted to visually inspect accessible external surfaces of piping, piping components, ducting, and other metallic and non-metallic components (including bolting) for aging degradation."
- In Section B2.1.14, External Surfaces Monitoring Program (Pages B-36, B-37), Program Description, the last sentence of the first paragraph is revised to read: "Periodic system inspections and walkdowns are conducted to visually inspect accessible external surfaces of piping, piping components, ducting, and other metallic and non-metallic components (including bolting) for aging degradation (e.g., evidence of loss of material, cracking and leakage)."

RAI AMP-B2.1.7-1:

The staff has determined that in the operating experience condition reports for LRA AMP B2.1.7, Boric Acid Corrosion Control Program, Prairie Island Nuclear Generating Plant (PINGP) has reported some instances of borated water leakage from valve package or flange gaskets or from bolted connections. However, PINGP did not incorporate this plant specific operating experience into the "operating experience" program element discussion for AMP B.2.1.7. Clarify what type of corrective actions are implemented for steel, copper alloy, and aluminum components that are exposed to borated water leakage or to boric acid residues that has precipitated out as a result of previous borated water leakage. Clarify whether the program permits PINGP to leave any boric acid residues in place, and if so, how the program assesses the impacts of boric acid residues on the structural integrity of impacted components if the residues are left in place for any period of time. Identify all relevant PINGP operating experience with boric water leakage or boric acid residues over the past five (5) years, and discuss the corrective actions that were taken on the impacted steel, copper alloy or aluminum alloy components in order to correct the adverse conditions.

NSPM Response to RAI AMP-B2.1.7-1

The PINGP Boric Acid Corrosion Program effectively monitors the condition of all systems and components containing borated water, including adjacent structures, components, and supports, and ensures that boric acid corrosion is being acceptably managed.

Part A

Corrective actions taken as a result of the identification of borated water leakage or boric acid residue may include a combination of cleaning, repair, and/or replacement activities. The PINGP Boric Acid Corrosion Program requires complete removal of boric acid crystal buildup or deposits as part of the corrective action. Active leakage, depending upon the source and the cause, may be corrected via gasket replacement, valve packing adjustment/replacement, joint disassembly/reassembly, component replacement, or other appropriate maintenance activities.

Borated water leakage and areas of resulting boric acid corrosion are documented, evaluated and, where necessary, corrected, via the PINGP Corrective Action Program (CAP). Corrosion evaluations consider the system design and licensing basis when determining whether an affected structure or component is acceptable for continued service.

Part B

The PINGP Boric Acid Corrosion Program does allow boric acid residues to be left in place if supported by evaluation. The following summarizes the process for conducting corrosion evaluations required by the program.

ASME Pressure Boundary Components

If boric acid leakage affects ASME Section XI pressure boundary components other than bolting (e.g.; valve bodies, valve bonnets, piping) then those components are evaluated to determine if the component is acceptable for continued service. IWA-5250, "Corrective Measures," states: "Components with local areas of general corrosion that reduce the wall thickness by more than 10% shall be evaluated to determine whether the component may be acceptable for continued service, or whether repair or replacement is required." Therefore, the corrosion evaluation ensures that, either:

a. If left in service, 10% wall loss will not occur prior to the time the component will be repaired, or,
b. If greater than 10% wall loss has or may occur, an evaluation of operation with the reduced wall thickness is performed.

Procedures specify that the evaluation should consider corrosion rates and mechanisms taking into account material susceptibility, surface temperature, leakage rates, boric acid concentration and potential for further concentration by evaporation or boiling.

If the corrosion evaluation determines that code allowables or margins for operability will not be exceeded prior to scheduled corrective maintenance, then it may be concluded that the system is acceptable for continued service pending subsequent re-inspections to validate assumptions, or other possible compensatory measures, if necessary. If the corrosion evaluation determines that corrosion allowables or margins for operability will be exceeded prior to scheduled maintenance, then the time remaining prior to such an exceedance is estimated, and an action is created to reinspect/reassess or perform corrective maintenance prior to that time.

Non-ASME or Non-Pressure Boundary ASME Components

Those indications which affect susceptible materials of non-ASME components or susceptible non-pressure boundary materials of ASME Section XI components (e.g.; packing components, stem and yoke) are evaluated. Procedures specify that a corrosion evaluation for a leak left in service should consider corrosion rates and mechanisms (consider surface temperature), boric acid concentration (and potential for further concentration by evaporation or boiling), material susceptibility, leak rates, corrosion allowance and design wall thickness, re-inspection interval, and possible compensatory measures, as necessary. If the corrosion evaluation determines that code allowables or margins for operability will not be exceeded prior to scheduled corrective maintenance, then it may be concluded that the system is acceptable for continued service pending subsequent re-inspections to validate assumptions, or other possible compensatory measures, if necessary. If the corrosion evaluation determines that corrosion allowables or margins for operability will be exceeded prior to scheduled maintenance, then the time remaining prior to such an exceedance is estimated and an action is created to reinspect/reassess or perform corrective maintenance prior to that time.

Mechanical Joints

Leakage from mechanical joints (e.g., bolted connections) that is determined to be acceptable for continued operation is inspected and monitored in order to trend/evaluate changes in leakage. The bases for acceptability are documented. Evaluations for continued service include consideration of corrosion mechanisms and corrosion rates.

<u>Part C</u>

Borated water leakage and boric acid crystal accumulations have been identified and corrected prior to causing any significant impact to safe operation or loss of material that would result in a loss of intended function. Adequate corrective actions were taken to prevent recurrence.

A document review of Corrective Action Program issues, NRC Inspection Reports, Program Self Assessments, Program Health Reports, and INPO Evaluations dating back to 2000, revealed instances where borated water or boric acid crystals were identified. Leakage or boric acid residue was observed on various valve stems, tubing fittings, valve to body joints, valve bellows, and flanged joints. The causes of the boric acid leakage were attributed to a variety of issues such as packing leakage; instrument tube fittings stripped or misaligned; valve bellows leakage; broken lock washers; failed O-rings; and gasket failures on valve body-to-bonnet joints, orifice flanges, and heat exchanger shell/channel head connections. Corrective actions involved cleaning the boric acid residue; replacing carbon steel studs and nuts with stainless steel; replacing valves and manifolds; adjusting or replacing valve packing; disassembling, cleaning, inspecting and replacing gaskets on valves, heat exchangers, and other flanged connections; adjusting the torque on valve body-to-bonnet and heat exchanger shell/channel head studs; replacing O-rings on transmitters; and tightening, rethreading, or replacing fittings. The boric acid leakage observed did not affect the structural integrity of any components.

Part D

The PINGP System Engineering staff is responsible for evaluating modifications to equipment, procedures, or specifications based on incidents involving corrosion or potential corrosion. Considerations include (1) reducing the probability of leakage in susceptible areas and (2) use of corrosion resistant materials for items such as body-to-bonnet valve studs or the application of protective coatings, cladding or leakage collection methods.

As an example of such corrective actions, PINGP Engineering implemented enhancements to valve packing procedures in order to address a number of packing leakage issues. The valve packing procedures were revised to incorporate improved valve repacking methods and techniques. Some of the key elements included instructions for packing consolidation, use of live-load packing assemblies, and the installation of hardened steel washers under the gland nut for better force transmission.

RAI AMP-B2.1.9-1:

Section B2.1.9 of the LRA states an exception to the "parameters monitored/inspected" program element of GALL AMP XI.M21, Closed-Cycle Cooling Water System. The exception states that some of the pumps and heat exchanger performance parameters recommended by the GALL Report are not used for monitoring specific pumps or smaller converters serviced by the closed-cycle cooling water systems. The information in the LRA is insufficient for the staff to evaluate the acceptability of this exception.

Please provide a more detailed description of this exception, stating which pumps and heat exchangers are affected by this exception, what performance parameters recommended in the GALL Report are not monitored, and what performance parameters are used in lieu of those recommended in the GALL Report. Also, provide a technical justification that the performance parameters proposed for use are adequate for aging management during the period of extended operation.

NSPM Response to RAI AMP-B2.1.9-1

As stated in the PINGP LRA, Appendix B2.1.9 (Page B-28), PINGP has taken an exception to NUREG-1801, Chapter XI, Program XI.M21, Element 3, Parameters Monitored/Inspected. The exception reads: "Some of the pump and heat exchanger performance parameters recommended by NUREG-1801 are not used by PINGP for monitoring specific pumps or smaller converters serviced by the closed-cycle cooling water systems. Chemical controls and established performance monitoring techniques, based on plant experience, are adequate to detect changes in system performance due to corrosion or cracking." The following discussion provides a more detailed description of this exception.

NUREG-1801, Program XI.M21, Element 3, recommends the following performance parameters to monitor the effects of aging: "For pumps, the parameters monitored include flow, discharge pressures, and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure." As an exception to this NUREG-1801 recommendation, the PINGP Closed-Cycle Cooling Water System Program includes the following performance parameters to monitor each closed-cycle cooling water loop within the scope of the program:

- Old Administration Building Chiller Loop (121 Lab and Service Area Chiller)

  Performance parameters monitored: Evaporator temperatures and pressure are monitored once in the spring, late summer, and winter.

  Additional aging management activities: Aging of the Old Administration Building Chiller Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are Nitrite (monthly), pH and Conductivity (monthly); Tolyltriazole (quarterly); and Adenosine Triphosphate (ATP) and Aerobic (monthly). The parameters tested by an outside laboratory are Nitrate (quarterly), Total Copper (monthly), Total Iron (monthly), Chloride (quarterly), Fluoride (quarterly), Sulfate (quarterly) and Ammonia (quarterly). Preventive maintenance is also performed annually on the chiller which includes monitoring the evaporator pressure and chilled water pressure and temperature.

  Based on the extensive chemistry sampling being performed and the pressures and temperatures being monitored, additional flow monitoring is deemed unnecessary.

- Cold Lab Chiller Loop

  Performance parameters monitored: None.

  Additional aging management activities: Aging of the Cold Lab Chiller Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested by an outside laboratory are Chloride and Sulfate (yearly), Nitrite (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly).

  Based on the extensive chemistry sampling being performed, additional monitoring for flow, pressure and temperature is deemed unnecessary.

- Computer Room Chiller Loop

  Performance parameters monitored: None.

  Additional aging management activities: Aging of the Computer Room Chiller Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are percent Glycol-Freeze Point (quarterly), pH and Conductivity (quarterly), and Tolyltriazole (yearly). The parameters tested by an outside laboratory are Chloride and Sulfate (yearly) and Total Iron (yearly).

  Based on the extensive chemistry sampling being performed, additional monitoring for flow, pressure and temperature is deemed unnecessary.

- D1 & D2 Diesel Generator Jacket Water Cooler Loops

  Performance parameters monitored: Pump flow and suction pressure are not monitored, but the discharge pressure is monitored every 18 months during the 24 hour load test. Obtaining flow measurements for process fluids is impractical due to heat exchanger by-pass flow modulation. Jacket water cooler flow is also not monitored, but the engine inlet and outlet temperatures are monitored during the monthly slow start test, the six month fast start test, and the 18 month 24 hour load test. The differential pressure for the coolers is not monitored. The jacket water coolers are in a stacked arrangement. Cooling water flow is directed out of one cooler immediately into the next in series. It is not possible to obtain accurate cooling water temperatures and pressures for each of the three heat exchangers. Performance monitoring is consistent with the PINGP commitments made in response to NRC Generic Letter 89-13.

  Additional aging management activities: Aging of the D1 & D2 Diesel Generator Jacket Water Cooler Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are Chromate (monthly) and pH and Conductivity (monthly). The parameters tested by an outside laboratory are Total Copper (monthly), Total Iron (monthly), Chloride (quarterly), Fluoride (quarterly) and Sulfate (quarterly). Eddy current testing of the tubes is conducted on the jacket water coolers with inspection intervals based on plant-specific and application-specific knowledge, as well as past history, current operating conditions and operating experience.

  Based on the extensive chemistry sampling being performed, the jacket water cooler eddy current testing, and the pressure and temperatures being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- D5 & D6 Diesel Generator High Temperature/Low Temperature (HT/LT) Radiator Loops

  Performance parameters monitored: The HT/LT cooling water temperature and pressure is monitored when performing the monthly slow start test, the six month fast start test, and the 18 month 24 hour load test. Monitoring of the flows is not practical due to the modulating thermostats for each of the HT and LT radiators.

Additional aging management activities: Aging of the D5 & D6 Diesel Generator HT/LT Radiator Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are percent Glycol-Freeze Point (quarterly), pH and Conductivity (quarterly), Tolyltriazole (yearly) and Nitrite (quarterly). The parameters tested by an outside laboratory are Chloride and Sulfate (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly). Coolant samples are further examined for visual rust, paint chips or other solid particles.

Based on the extensive chemistry sampling being performed and the pressures and temperatures being monitored, additional performance monitoring is deemed unnecessary.

- 12 & 22 Diesel Cooling Water Pump Jacket Cooling Heat Exchanger Loops

Performance parameters monitored: Several factors prevent performance testing of the jacket heat exchangers. No cooling water temperature or flow instrumentation is installed. When operating, the system is not at a steady state condition since jacket coolant flow is thermostatically modulated. In addition, cooling water system demand and configuration place a relatively low load on the diesel when it is operated. Flow measurement is not practical for cooling water flows. Difficulty exists in obtaining useful fluid temperature measurements on the process or cooling water side due to the small heat load on the equipment. High and low jacket water temperatures are monitored during the 12 & 22 Diesel Cooling Water Pump monthly tests. However, monitoring of flows, pressures and other temperatures is not practical. Performance monitoring is consistent with the PINGP commitments made in response to NRC Generic Letter 89-13.

Additional aging management activities: Aging of the 12 & 22 Diesel Cooling Water Pump Jacket Cooling Heat Exchanger Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are Nitrite (monthly), pH and Conductivity (monthly), Tolyltriazole (quarterly) and ATP and Aerobic (monthly). The parameters tested by an outside laboratory are Nitrate (quarterly), Total Copper (monthly), Total Iron (monthly), Chloride (quarterly), Fluoride (quarterly), Sulfate (quarterly) and Ammonia (quarterly). Eddy current testing of the tubes is conducted on the jacket cooling heat exchangers with inspection intervals based on plant-specific and application-specific knowledge, as well as past history, current operating conditions and operating experience.

Based on the extensive chemistry sampling being performed, the jacket cooling heat exchanger eddy current testing, and the temperatures being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- 122 Diesel Fire Pump Heat Exchanger Loop

  Performance parameters monitored: The cooling water temperature is monitored when performing the diesel fire pump weekly test, when performing the fire protection pumps monthly test, and when performing the fire protection system fire pumps 18 month test. Monitoring of the flows, pressures and inlet/outlet temperatures is not practical due to the modulating engine thermostats.

  Additional aging management activities: Aging of the 122 Diesel Fire Pump Heat Exchanger Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are percent Glycol-Freeze Point (quarterly), pH and Conductivity (quarterly), Tolyltriazole (yearly) and percent Nitrite (quarterly). The parameters tested by an outside laboratory are Chloride and Sulfate (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly). Coolant samples are further examined for solids or oil products and coolant is replaced every other year.

  Based on the extensive chemistry sampling being performed and the temperatures being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- 121 & 122 Auxiliary Building Hot Water Converter Loops

  Performance parameters monitored: Pump suction pressure, pump discharge pressure and converter temperatures are monitored during system startup.

  Additional aging management activities: Aging of the 121 & 122 Auxiliary Building Hot Water Converter Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are percent Glycol-Freeze Point (quarterly), pH and Conductivity (quarterly) and Tolyltriazole (yearly). The parameters tested by an outside laboratory are Ammonia (yearly), Chloride and Sulfate (yearly), Nitrite (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly).

  Based on the extensive chemistry sampling being performed and the pressures and temperatures currently being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- 121 & 122 Turbine Building Hot Water Converter Loops

  Performance parameters monitored: Pump suction pressure, pump discharge pressure and converter temperatures are monitored during system startup.

  Additional aging management activities: Aging of the 121 & 122 Turbine Building Hot Water Converter Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are percent Glycol-Freeze Point (quarterly), pH and Conductivity (quarterly) and Tolyltriazole (yearly).

The parameters tested by an outside laboratory are Ammonia (yearly), Chloride and Sulfate (yearly), Nitrite (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly).

Based on the extensive chemistry sampling being performed and the pressures and temperatures currently being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- 121 Administration Building Hot Water Converter Loop

  Performance parameters monitored: Pump suction pressure, pump discharge pressure and converter temperatures are monitored during system startup.

  Additional aging management activities: Aging of the 121 Administration Building Hot Water Converter Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are Nitrite (monthly), pH and Conductivity (monthly), Tolyltriazole (quarterly) and ATP and Aerobic (monthly). The parameters tested by an outside laboratory are Nitrate (quarterly), Total Copper (monthly), Total Iron (monthly), Chloride (quarterly), Fluoride (quarterly), Sulfate (quarterly), Ammonia (quarterly) and Coupon Inspection (yearly or per chemistry schedule).

  Based on the extensive chemistry sampling being performed and the pressures and temperatures currently being monitored, additional flow, pressure and temperature monitoring is deemed unnecessary.

- Hot Lab Chiller Loop

  Performance parameters monitored: None.

  Additional aging management activities: Aging of the Hot Lab Chiller Loop is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested by an outside laboratory are Chloride and Sulfate (yearly), Nitrite (yearly), Nitrate (yearly), Total Copper (yearly) and Total Iron (yearly).

  Based on the extensive chemistry sampling being performed, additional monitoring for flow, pressure and temperature is deemed unnecessary.

- 11, 12, 21, & 22 Component Cooling Water Heat Exchanger Loops

  Performance parameters monitored: Pump discharge pressure, suction pressure and heat exchanger outlet flow and pressure are monitored quarterly. Heat Exchanger inlet/outlet temperatures and flow are monitored during a performance test each refueling outage. Performance monitoring is consistent with the PINGP commitments made in response to NRC Generic Letter 89-13.

Additional aging management activities: Aging of the 11, 12, 21, & 22 Component Cooling Water Heat Exchanger Loops is managed by sampling and controlling the coolant chemistry on a periodic basis. The parameters tested in-house are Chromate (weekly), pH and Conductivity (weekly), Gross Activity (quarterly) and Suspended Solids (monthly). The parameters tested by an outside laboratory are Total Copper (monthly), Total Iron (monthly), Chloride (quarterly), Fluoride (quarterly) and Sulfate (quarterly) and Coupon Inspection for Unit 1 only (yearly or per chemistry schedule). Eddy current testing of the tubes is performed at intervals based on plant specific and application-specific knowledge, as well as past history, current operating conditions and operating experience.

Based on the extensive chemistry sampling being performed, periodic heat exchanger eddy current testing, and the flow, pressure and temperatures being monitored, additional pressure (i.e., heat exchanger differential pressure) monitoring is deemed unnecessary.

Conclusion

The Closed-Cycle Cooling Water System Program is both a preventive and condition monitoring program that is based on the Electric Power Research Institute (EPRI) "Closed Cooling Water Chemistry Guideline," TR-107396, Revision 1. The program includes preventive measures to minimize corrosion, heat transfer degradation, and stress corrosion cracking (SCC); and testing and inspection to monitor the effects of corrosion, heat transfer degradation, and SCC on the intended functions of the components. The preventive measures consist of maintaining the system corrosion inhibitor concentrations within the specified limits by periodic testing. Testing is performed to verify key chemistry parameters and to measure impurities, conductivity and microbiological growth. Visual inspections are performed to identify corrosion, fouling and SCC that may be present. Cleaning and inspection of heat exchangers are performed periodically along with pump and heat exchanger performance/functional testing. The current level of performance testing (as defined by the specific performance parameters monitored listed above) is adequate to detect changes in system performance due to aging. The overall combination of water chemistry control, testing and inspection provide reasonable assurance that the components within the scope of this program will continue to perform their intended functions.

RAI AMP-B2.1.14-1:

GALL recommends that XI.M36, "External Surfaces Monitoring," is only applicable to detect loss of material due to general, pitting and crevice corrosion for steel (carbon steel) components. However based on the review of the LRA and the applicant's program basis document, the staff noted that the scope of this program will be expanded to include other metallic and non-metallic materials and additional aging effects that include cracking or change in material properties due to ozone, ultra violet or thermal exposure, loss of material due to wear and galvanic corrosion, heat transfer degradation due to fouling. The proposed expansion of AMP B2.1.14 is beyond the scope of GALL AMP XI.M36, which was meant for steel components and loss of material only.

- Please provide an appropriate program to manage the non-metallic components and their associated aging effects.

- Please justify why the aging effect of heat transfer degradation due to fouling, as it applies to the additional metallic components added to the scope of this program, is not considered an enhancement to the program element, "scope of program", of GALL AMP XI.M36.

- Please justify how this program will adequately manage the aging effects of loss of material and heat transfer degradation and their applicable aging mechanism, as it applies to the additional metallic components added to the scope of this program.

NSPM Response to RAI AMP-B2.1.14-1

Part A

The External Surfaces Monitoring Program described in Section B2.1.14 of the LRA is an appropriate program for managing aging of certain non-metallic components. The aging effects applicable to non-metallic materials include cracking, loss of material due to wear, and change in material properties.

Aging effects in non-metallic materials are detectable by visual examination as surface discontinuities such as cracking, crazing, peeling, blistering, chalking, flaking, physical distortion, discoloration, loss of material due to wear, and evidence of leakage. In some non-metallic components such as flexible hoses, the visual inspection will be coupled with a physical manipulation of the material to verify the absence of aging effects such as hardening, embrittlement, or gross softening. The External Surfaces Monitoring Program uses visual examinations (coupled where appropriate with physical manipulation) as the inspection method for external surfaces of both metallic and non-metallic materials.

Even though non-metallic materials are not explicitly mentioned in NUREG-1801 for this program, the same type of visual inspection that is used for metallic materials is effective for identification of aging effects in non-metallic materials. Since the inspection methodology of NUREG-1801, Program XI.M36 is applicable to non-metallic materials, inclusion of non-metallic materials is neither considered an exception nor an enhancement. There are numerous precedents in the License Renewal arena where the NRC has found the External Surfaces Monitoring Program acceptable for managing aging of non-metallic materials without considering their inclusion as an exception or enhancement. The most recent example is documented on Page 3-22 of the Safety Evaluation Report Related to the License Renewal of Wolf Creek Generating Station.

Part B

The aging effect of heat transfer degradation due to fouling is appropriately managed by the External Surfaces Monitoring Program for the applicable components. The PINGP LRA only applies the External Surfaces Monitoring Program for management of this aging effect on the external surfaces of cooling coils exposed to an external air environment. Under this program, the external surfaces of cooling coils are visually inspected for evidence of fouling. The air coolers included in the scope of the External Surfaces Monitoring Program include the air compressor motor unit coolers (included in LRA Table 3.3.2-6, Cooling Water System, on Page 3.3-129); diesel generator radiator, aftercooler and air coolant heat exchanger tubes (included in LRA Table 3.3.2-8, Diesel Generators and Support System, on Page 3.3-163); fire pump enclosure cooler (included in LRA Table 3.3.2-9, Fire Protection System, on Page 3.3-199); and ventilation system cooling coils (included in LRA Table 3.3.2-5, Control Room and Miscellaneous Area Ventilation System, on Page 3.3-112, and in LRA Table 3.3.2-14, Primary Containment Ventilation System, on Page 3.3-278).

The visual inspections performed by the External Surfaces Monitoring Program are capable of identifying corrosion, discoloration, and accumulation of dirt/debris. These parameters would indicate whether the heat transfer surfaces are fouled such that heat transfer to the external air environment may be degraded. Using the visual inspections under this program to inspect for fouling of heat transfer surfaces, in addition to other external aging effects, is not considered an enhancement.

The program enhancement referenced in LRA Section B2.1.14 (Page B-37) states that the scope of the existing External Surfaces Monitoring Program will be expanded to include all metallic and non-metallic components within the scope of License Renewal which require aging management under this program. The purpose of the enhancement is to ensure that procedures for future program inspections are comprehensive and clearly include all components in the scope of License Renewal which rely on this program for aging management. The enhancement acknowledges that some components which will credit this program may not already be identified in existing implementing procedures. The enhancement does not suggest that PINGP considered the application of this program to materials other than steel to be an enhancement. With the enhancements that are identified in LRA Section B2.1.14, the program will be consistent with the elements in NUREG-1801, Chapter XI, Program XI.M36, External Surfaces Monitoring, and can be relied on to inspect the components which credit this program in the LRA.

Part C

The visual inspections performed by the External Surfaces Monitoring Program are capable of identifying the necessary aging effects associated with the metallic components subject to the program. The metallic materials included in the scope of this program are carbon steel, galvanized steel, cast iron, aluminum, copper alloy, copper-nickel, chrome-molybdenum alloy, carbon steel with stainless steel clad, and ductile iron. The program manages the aging effects of loss of material due to corrosion and heat transfer degradation due to fouling of these metallic components.

The External Surfaces Monitoring Program uses visual examinations as the inspection method for external surfaces of metallic materials. The following inspection parameters are monitored:

- Corrosion wastage
- Loss of material
- Oxidation
- Discoloration
- Cracking
- Coating degradation
- Accumulation of dirt/debris
- Evidence of leakage
- Surface discontinuities
- Pitting

The External Surfaces Monitoring Program performs visual inspections at least once per refueling cycle using qualified personnel and controlled procedures and processes. The program uses standardized monitoring and trending to track degradation. A walkdown checklist is utilized while conducting the walkdown inspections and deficiencies, problems and concerns are documented and corrective action is initiated as appropriate. Therefore, the External Surfaces Monitoring Program is capable of managing the various aging effects of interest in the components subject to the program.

RAI AMP-B2.1.15-1:

The Fire Protection Program basis document states that the diesel-driven fire pump inspection activities require that the pump be periodically performance tested. PINGP credits the Fire Protection program to manage cracking in the fuel oil lines. Please confirm how the periodic performance test will manage the aging effect of cracking in the fuel oil lines.

NSPM Response to RAI AMP-B2.1.15-1

As recommended in NUREG-1801, Chapter XI, Program XI.M26, "Fire Protection," Element 4, periodic performance tests of the diesel-driven fire pump are conducted to ensure fuel supply line performance. The performance tests detect degradation of the fuel supply line before the loss of the component intended function. Consistent with this GALL recommendation, the PINGP Fire Protection Program requires that the diesel-driven fire pump be periodically performance tested to ensure that the fuel supply line can perform its intended function. The fuel supply line intended function is confirmed by starting and running the diesel-driven fire pump for 30 minutes every week. The periodic pump performance test provides an indirect means of verifying the absence of fuel line cracking by confirming satisfactory pump performance.

In addition, as shown in LRA Table 3.3.2-9 (Page 3.3-206), the internal surface of the diesel-driven fire pump fuel oil supply line is managed for cracking by the Fuel Oil Chemistry Program and the One-Time Inspection Program. The Fuel Oil Chemistry Program monitors fuel oil quality and the levels of water, sediment, and contaminants which can result in cracking of fuel oil piping. Fuel oil sampling and the use of established acceptance criteria provide assurance that fuel oil contaminants are maintained within acceptance limits, thereby providing an environment that mitigates aging effects. The One-Time Inspection Program is used to verify the effectiveness of the Fuel Oil Chemistry Program and to confirm that aging degradation is not occurring. The One-Time Inspection Program uses a representative sampling approach and established nondestructive examination techniques (e.g., enhanced visual examination to detect cracking) to ensure that there is no cracking due to aging of the fuel oil supply line.

As described above, the combination of aging management activities performed in accordance with the requirements of the Fire Protection, Fuel Oil Chemistry, and One-Time Inspection Programs provide reasonable assurance that cracking of the diesel-driven fire pump fuel supply line will be adequately managed for the period of extended operation.

RAI AMP-B2.1.15-2:

The GALL AMP XI.M26 in the "acceptance criteria" element recommends no corrosion is acceptable in the fuel supply line for the diesel-driven fire pump. Acceptance criteria element under Section 5.6 of the program basis document states that the diesel driven fire pump is flow tested to ensure there is no indication of internal fuel supply line corrosion. Please explain how the flow test will ensure there is no corrosion.

NSPM Response to RAI AMP-B2.1.15-2

As recommended in NUREG-1801, Chapter XI, Program XI.M26, "Fire Protection", Element 4, periodic performance tests of the diesel-driven fire pump are conducted to ensure fuel supply line performance. The performance tests detect degradation of the fuel supply line before the loss of the component intended function. Consistent with this GALL recommendation, the PINGP Fire Protection Program requires that the diesel-driven fire pump be periodically performance tested to ensure that the fuel supply line can perform its intended function. The fuel supply line intended function is confirmed by starting and running the diesel-driven fire pump for 30 minutes every week. The periodic pump performance test provides an indirect means of verifying the absence of fuel line corrosion by confirming satisfactory pump performance.

In addition, as shown in LRA Table 3.3.2-9 (Pages 3.3-206, 3.3-207), the internal surface of the diesel-driven fire pump fuel oil supply line is managed for loss of material due to corrosion by the Fuel Oil Chemistry Program and the One-Time Inspection Program. The Fuel Oil Chemistry Program monitors fuel oil quality and the levels of water, sediment, and contaminants which can result in corrosion of fuel oil piping. Fuel oil sampling and the use of established acceptance criteria provide assurance that fuel oil contaminants are maintained within acceptance limits, thereby providing an environment that mitigates aging effects. The One-Time Inspection Program is used to verify the effectiveness of the Fuel Oil Chemistry Program and to confirm that aging degradation is not occurring. The One-Time Inspection Program uses a representative sampling approach and established nondestructive examination techniques to ensure that there is no corrosion due to aging of the fuel oil supply line.

As described above, the combination of aging management activities performed in accordance with the requirements of the Fire Protection, Fuel Oil Chemistry, and One-Time Inspection Programs provide reasonable assurance that corrosion of the diesel-driven fire pump fuel supply line will be adequately managed for the period of extended operation.

RAI AMP-B2.1.15-3:

The GALL AMP XI.M26 recommends once every six months for performance testing of the Halon system. In the LRA, PINGP takes an exception to performance testing of Halon smoke detectors. PINGP performance testing ranges from once every three years to once every five years. Please provide a basis for using a different frequency than the GALL Report recommended frequency.

NSPM Response to RAI AMP-B2.1.15-3

The three halon fire suppression systems at PINGP afford protection to the service building computer room, guardhouse, and the old administration building records vault. As defined in the PINGP fire hazards analysis, a fire in these plant areas would have no effect on the safe shutdown capability of the plant. In the case of a service building computer room fire, an old administration building records vault fire, or a guardhouse fire, all Unit 1 and Unit 2 safe shutdown functions would remain available from the Control Room. Additionally, no process monitoring instrumentation in the Control Room would be affected by fires in these areas. As described in PINGP USAR Section 10.3.1.3.1, the performance description and operability requirements of the fire detection and fire protection systems are described in and governed by the PINGP Operations Manual. There are no specific operability or surveillance requirements defined for the three halon suppression systems in the Operations Manual.

The three halon fire suppression systems are visually inspected every six months to ensure adequate halon availability by verifying the level of each halon cylinder. In addition, the smoke detectors in the service building computer room are functionally tested every three years. The smoke detectors in the guardhouse and the old administration building records vault are functionally tested every five years. The enhancement in the PINGP LRA, Appendix B2.1.15, that states that the Fire Protection Program will be enhanced to require functional testing of the halon system smoke detectors in the guardhouse every 5 years, is in error. PINGP has determined that the halon system smoke detectors in the guardhouse are already being functionally tested every 5 years, and this enhancement is unnecessary. Accordingly, the LRA is hereby revised as follows:

> In LRA Section B2.1.15 on Page B-39, under Enhancements, the first bullet "Parameters Monitored/Inspected" with the proposed enhancement "The Fire Protection Program will be enhanced to require functional testing of the halon system smoke detectors in the guardhouse every 5 years," is deleted in its entirety.

It has also been determined that the exception discussed in LRA Section B2.1.15 related to halon testing requires revision. The associated LRA revision is as follows:

> In LRA Section B2.1.15 on Page B-39, under Exceptions to NUREG-1801, the second paragraph under Parameters Monitored/Inspected is revised in its entirety to read as follows: "The halon system smoke detectors in the service building computer room are functionally tested every 3 years and those in the old administration building records vault and guardhouse are functionally tested every 5 years, instead of every six months as recommended in NUREG-1801, XI.M26. Functional testing of the smoke detectors in the computer room every 3 years and those in the vault and guardhouse every 5 years will be sufficient to identify degradation that may affect the performance of the systems."

To reflect deletion of the enhancement, Commitment Number 12 contained in the LRA transmittal letter dated April 11, 2008, requires revision. Commitment Number 12 is hereby revised to read as follows:

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
12	The Fire Protection Program will be enhanced to require periodic visual inspection of the fire barrier walls, ceilings, and floors to be performed during walkdowns at least once every refueling cycle.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.15

A review of PINGP operating experience identified no adverse trends or issues with the halon smoke detectors. The halon smoke detector functional testing frequencies of three and five years in lieu of every six months as recommended by NUREG-1801, is based on the maintenance history for each of the three systems. Agreement on these functional testing frequencies has been reached with the PINGP insurance underwriter, Nuclear Electric Insurance Limited (NEIL).

Functional testing of the halon smoke detectors in the service building computer room every three years, and testing of those in the guardhouse and the old administration building records vault every five years, will be sufficient to identify degradation that may affect the performance of the systems. The halon systems will also be inspected periodically at a frequency of at least once per refueling cycle by the External Surfaces Monitoring Program for corrosion and mechanical damage.

RAI AMP-B2.1.17-1:

The "monitoring and trending" element in GALL AMP XI.M17 states that CHECKWORKS or a similar predictive code is used to predict component degradation in the systems conducive to flow accelerated corrosion (FAC), as indicated by specific plant data, including material, hydrodynamic, and operating conditions. PINGP stated that CHECKWORKS was implemented in late 2004. Please provide any operating experience such as excessive FAC requiring repair or replacement of piping that was the basis for converting to CHECKWORKS.

NSPM Response to RAI AMP-B2.1.17-1

Prior to 2004, the PINGP Flow-Accelerated Corrosion (FAC) Program utilized a software application referred to as the Pipe Thinning Inspection Program (PTIP), which was developed by NSPM. The software program lacked certain features (e.g.; had no predictive capability, did not consider plant chemistry, offered limited trending ability) and did not meet the NMC standard for a predictive code for the FAC Program. This resulted in its replacement in 2004 with the EPRI CHECWORKS SFA (Steam/Feedwater Application), which was considered both the industry standard and the NMC standard.

PINGP upgraded to the CHECWORKS SFA model in order to improve its FAC Program through implementation of a more robust predictive code. The CHECWORKS application provided improved modeling capabilities and other features that were previously unavailable via the PTIP application. There were no FAC-related failures identified at PINGP that prompted the upgrade to CHECWORKS.

RAI AMP-B2.1.17-2:

FAC Program document FP-PE-FAC-01, Section 5.8.3 states under component evaluations to compare CHECKWORKS measured and predicted thickness. Has PINGP established a correlation between predicted results and actual wall thickness measurements? Has PINGP had excessive FAC that was not predicted by CHECKWORKS?

NSPM Response to RAI AMP-B2.1.17-2

Wear rate analyses are performed using the CHECWORKS SFA model. A Pass 1 Wear Rate Analysis is an analysis based solely on the plant predictive model, and is not enhanced by results of the plant wall thickness measurements. A Pass 2 Wear Rate

Analysis generates predicted wear rate and remaining service life similar to a Pass 1 Wear Rate Analysis with one significant difference; results incorporate inspection data. Pass 1 Analysis results are not relied on by themselves to select locations for examination.

After each inspection period, a Pass 2 Analysis is performed on each Analysis Line. An Analysis Line is defined as one or more physical lines of piping that have been analyzed together in the CHECWORKS model. As an output of the Pass 2 Analysis, CHECWORKS correlates the measured wear to the predicted wear for each Analysis Line.

When calculating a component's remaining service life (RSL) and schedule for examination, both the measured wear rate and CHECWORKS predicted wear rate, among other things, are considered. The CHECWORKS predicted wear rate from a Pass 2 Analysis provides an important input to these FAC Program considerations, especially after an Analysis Line has accumulated sufficient field measurement data to indicate a reliable correlation with predictions.

A Pass 2 Analysis has been completed through the current operating cycle for each Unit. The predictive plant model includes inspection data of the most recent outage for both Units (Refueling Outage 25; March 2008 for Unit 1, October 2008 for Unit 2). In general, the field measured wear shows a moderate to good correlation (within +/- 50%) to the CHECWORKS predicted wear. PINGP has not experienced excessive flow accelerated corrosion (FAC) that was not predicted by CHECWORKS.

RAI AMP-B2.1.17-3:

FAC Program document FP-PE-FAC-01, Section 5.8.4.4 states that system changes could increase wear rates or subsequent reinspection could indicate significantly higher wear rates. What process/procedure is used to address changes in the chemical, operating and flow conditions that could impact remaining life predictions? How are these changes factored into the FAC program so that the remainder service life can be reevaluated?

NSPM Response to RAI AMP-B2.1.17-3

PINGP Flow-Accelerated Corrosion (FAC) procedures require that if system conditions appear to have changed in such a way as to increase wear rates, or subsequent reinspections indicate that wear rates are significantly higher than previously predicted, then consideration should be given to conducting inspections at an increased frequency. Additionally, plant operating conditions are taken into consideration for FAC based upon recommendations from the PINGP System Engineering, Chemistry, Operations, and Maintenance Departments.

The PINGP Strategic Water Chemistry Plan recognizes the importance of minimizing FAC on the secondary cycle components. FAC is mainly influenced by the at-temperature pH and oxygen content around the secondary cycle. The PINGP amine chemistry control program is optimized to minimize FAC of secondary system components. The Chemistry Department maintains the system chemistries in accordance with site-specific chemistry procedures to minimize the effects of corrosion. The procedures provide for water sampling, chemical treatment application and corrosion monitoring of applicable systems. Secondary chemistry is reviewed and is input into the Unit 1 and Unit 2 CHECWORKS SFA model.

PINGP modification design procedures require notification of the FAC Program Owner when plant modifications are determined to impact the FAC Program. Design considerations that may impact the FAC Program include changes to system flow rates, temperatures, pressures, water chemistry, valve lineups, materials, system configuration, piping or component geometries, or revisions to isometric drawings. Upon notification, the FAC Program Owner provides applicable design inputs to the modification, or evaluates the impact of the modification on the FAC Program.

Changes to system parameters, such as component material, water chemistry, and power level, are factored into the PINGP CHECWORKS SFA model so that the remaining service life can be reevaluated. Conversely, the CHECWORKS SFA model is also used to provide input to material changes, water chemistry changes, and piping design. The FAC Program, through the use of CHECWORKS SFA, is used to reduce the site's susceptibility to FAC, thereby increasing plant safety.

RAI AMP-B2.1.17-4:

GALL AMP XI.M17 in the "monitoring and trending" element states that inspection results are evaluated to determine if additional inspections are needed. Please provide information on how PINGP expands sample size. What acceptance criterion is used for sample expansion? Is it related to thickness or to wear rates? Is there a different value used for safety related and non-safety related piping?

NSPM Response to RAI AMP-B2.1.17-4

Part A

In accordance with the PINGP Flow-Accelerated Corrosion (FAC) Program implementing procedure, the criteria for sample expansion and the sample expansion guidelines are as follows:

"To ensure CHECWORKS SFA model prediction accuracy, the following sample expansion guidelines have been established.

1. If examination results are unexpected and inconsistent with predictions, and have a significant negative effect on component remaining service life, and are solely

attributable to FAC wear and not weld prep (counterbore), then the sample should be expanded to include the following (unless they have been examined within three inspection periods):

a. Any component within two diameters downstream of the component displaying significant wear or within two diameters upstream if that component is an expander or expanding elbow.

b. A minimum of the next two most susceptible components from the relative wear ranking in the same train as that containing the piping component displaying significant wear.

c. Corresponding components in each other train of a multi-train run with a configuration similar to that of the piping component displaying significant wear.

2. If inspections of the expanded sample specified under Item (1) above detect additional components with significant FAC wear, then the sample should be further expanded to include:

   a. Any component within two diameters downstream of the component displaying significant wear or within two diameters upstream if that component is an expander or expanding elbow.

   b. A minimum of the next two most susceptible components from the relative wear ranking in the same train as that containing the piping component displaying significant wear.

3. If inspections of the expanded sample specified under Item (2) above detect additional components with significant wear, then expansion of the sample specified under Item (2) should be repeated until no additional components with significant wear are detected.

The sample expansion guidelines are intended to add more examination data to calibrate the CHECWORKS SFA model, thereby increasing the accuracy of the predictions."

Part B

Sample expansion is based upon wall thickness (e.g., measured wall thickness significantly less than predicted wall thickness) and wear rate (e.g., results negatively affecting remaining service life).

Part C

The FAC Program is applicable to both safety related and non-safety related piping systems susceptible to FAC. The inspection sample is a subset of the systems that make up the overall program scope and generally represents the most FAC-susceptible piping in the plant. The sample expansion guidelines are applicable to all in-scope piping, and are applied consistently to both safety related and non-safety related piping.

RAI AMP-B2.1.17-5:

GALL AMP XI.M17 in the "detection of aging effects" element states, "The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function." Please clarify how PINGP calculates minimum permitted wall thickness to avoid loss of intended function and how it is used for the determination of the schedule of inspections in the FAC analysis.

NSPM Response to RAI AMP-B2.1.17-5

Per the requirements of the PINGP Flow-Accelerated Corrosion (FAC) Program, the minimum permitted wall thickness or Code Minimum Wall Thickness (t_{min}) is calculated in accordance with the original construction code which is USAS B31.1.0, Power Piping, 1967 Edition. Additionally, the program may define a Critical Wall Thickness (t_{crit}) for a component, as determined by engineering analysis. The critical wall thickness is typically a larger value than t_{min}. In turn, the remaining service life for a component is the estimated number of years until the wall thickness violates t_{min}, t_{crit}, or other established acceptance criteria. The remaining service life is based on measured wear rates or the predicted wear rates calculated by the CHECWORKS SFA application. The remaining service life is used to determine the appropriate future inspection schedule.

The FAC Program schedules follow-on examinations for specific components based upon previous examinations and evaluation results. Follow-on examinations are scheduled no later than the normal inspection period (e.g., refueling outage) preceding the end of the predicted FAC remaining service life of the component. Engineering judgment and an appropriate safety factor (per the guidance of NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program") are utilized when scheduling follow-on exams. Typically, follow-on examinations are scheduled at half of the remaining service life and no later than the normal inspection period prior to the point at which the calculated t_{min} or t_{crit} is reached.

The extent and schedule of the examinations assure detection of wall thinning before the loss of intended function.

RAI AMP-B2.1.18-1:

Please provide the following additional information relative to the following program element recommendations in GALL AMP XI.M37, "Flux Thimble Tube Inspection:"

1) The "acceptance criteria" program element in GALL AMP XI.M37 states in part that:

> Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and amendments there to, should be justified.

State what the current acceptance criteria are for the Flux Thimble Tube Inspection Program. Justify the use of your current acceptance criteria if the current acceptance criteria for the program differs from those previously committed to in the PINGP response to Bulletin 88-09. Clarify how the acceptance criterion for capping a thimble tube and taking a thimble tube out of service differs from the acceptance criterion used to reposition a thimble tube. Clarify how many times a thimble tube may be repositioned if the tube continues to exhibit evidence of wear following an initial repositioning of the component.

2) The "acceptance criteria" program element in GALL AMP XI.M37 states:

> The wall thickness measurements will be trended and wear rates will be calculated. Examination frequency will be based upon wear predictions that have been technically justified as providing conservative estimates of flux thimble tube wear. The interval between inspections will be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. The examination frequency may be adjusted based on plant-specific wear projections. Re-baselining of the examination frequency should be justified using plant specific wear-rate data unless prior plant-specific NRC acceptance for the re-baselining was received. If design changes are made to use more wear-resistant thimble tube materials (e.g., chrome-plated stainless steel) sufficient inspections will be conducted at an adequate inspection frequency, as described above, for the new materials.

Clarify whether the inspection frequencies for flux thimble tubes at PINGP Units 1 and 2 are based on the unit specific wear data and wear rates established from the data or on the generic wear rate value that is provided in Proprietary Class 2 WCAP-12866. If the generic wear rate value is used as your basis, justify its use for projecting the inspection frequency for the thimble tubes, as there is no assurance that the generic wear rate value is conservative relative to wear rates established from the PINGP unit-specific wear data.

NSPM Response to RAI AMP-B2.1.18-1

<u>Part 1) Acceptance Criteria</u>

A) The current acceptance criteria associated with the Flux Thimble Tube Inspection Program are as follows:

- Any flux thimble tube measuring greater than or equal to 80% through wall loss shall be capped.

- Any flux thimble tube measuring greater than or equal to 60% through wall loss shall be repositioned if outage time permits, or capped if the trend is approaching the capping criteria.

The acceptance criteria ensure that no leaks will occur in the flux thimble tubes prior to the next inspection, thereby maintaining the integrity of the reactor coolant system pressure boundary.

B) Prairie Island responded to NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors" with an inspection program based on limited industry experience and conservative engineering judgment pending the outcome of the Westinghouse Owners Group (WOG) Bottom Mounted Instrumentation Program. The initial inspection program called for the inspection of all incore flux thimble tubes during each refueling outage, and included acceptance criteria of repositioning at 40% wall loss and capping at 50% wall loss.

In October 1992, Prairie Island received the results of the WOG program as documented in WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear." The WOG compiled eddy current data from 2, 3, and 4 loop Westinghouse plants and trended the results. In addition, samples from both intact and degraded thimble tubes were analyzed and tested. Based upon thimble segment collapse tests, WCAP-12866 concluded that the thimble tubes have a high residual strength even when subject to a wall loss of 90%. The thimble tubes retained their functional and structural integrity up to 85% wall loss. As a result of these studies, the Westinghouse Owners Group recommended that the thimble tubes be repositioned, replaced, or capped when the wall loss reaches 80%. In response to this recommendation, Prairie Island revised the acceptance criteria for its Flux Thimble Tube Inspection Program in December 1992 to the current acceptance criteria outlined above (i.e.; 80% - cap, 60% - reposition). This action was conservative relative to the WOG recommendation in that repositioning would take place at a wall loss of 60% to ensure that the 80% capping criteria would not be reached.

C) The acceptance criteria of repositioning a flux thimble tube at greater than or equal to 60% wall loss, ensures that no leaks will occur in the flux thimble tubes prior to the next inspection, thereby maintaining the integrity of the reactor coolant system pressure boundary. Repositioning is performed at 60% through wall loss to ensure that the 80% capping criteria is not reached.

D) A thimble tube can be repositioned to a core location that has historically demonstrated little or no thimble tube wall loss. There are no specific criteria regarding the number of times a thimble tube may be repositioned. Should a thimble tube be repositioned enough times that the flux thimble can no longer be placed in a position in the reactor vessel internals to provide meaningful information, then that thimble tube would be capped. The program owner is responsible for review of inspection results and initiation of any necessary corrective actions.

Part 2) Monitoring and Trending

All flux thimble tubes at PINGP Units 1 and 2 are inspected every refueling outage. This inspection frequency has been in place since 1987, when the first flux thimble tube inspections were conducted. PINGP procedures allow less frequent inspections to be performed if they are technically justified based on long term historical data trends. The inspection frequency for flux thimble tubes at PINGP is based on unit specific wear data and wear rates established from that data. The generic wear rate value provided in WCAP-12866 would not be used to adjust the PINGP inspection frequency.

RAI AMP-B2.1.20-1

The GALL Report AMP XI.E6, under "Program Description," states that the aging management program for fuse holders (metallic clamps) needs to account for the following stressors, if applicable: fatigue, mechanical stress, vibration, chemical contamination, and corrosion. The applicant's Fuse Holder Program under the same program element states that the aging management program for fuse holders (metallic clamps) manages the effects of aging from adverse localized environments. Adverse localized environment is defined in the GALL Report as high heat, high radiation, or high moisture.

The staff requests that the applicant explain how the environment of the applicant's fuse holder program is consistent with those in the GALL Report AMP XI.E6.

NSPM Response to RAI AMP-B2.1.20-1

The use of the terminology "adverse localized environment" in the Fuse Holders Program was intended to encompass the term "stressors" in the GALL. To remove confusion, the affected LRA sections are hereby revised to remove reference to "adverse localized environments" in the descriptions of the Fuse Holder Program, as follows:

In LRA Section A2.20, "Fuse Holders Program," on Page A-9, the existing program description is replaced in its entirety with a new program description, to read as follows:

> "A2.20 Fuse Holders Program
>
> The Fuse Holders Program is a condition monitoring program that implements periodic visual inspections and tests of fuse holders in scope of License Renewal, located in passive enclosures and assemblies, and exposed to stressors that could affect the electrical circuit (metallic connection with the fuse) if left unmanaged during the period of extended operation. The Fuse Holders Program accounts for the following stressors, if applicable: fatigue, mechanical stress, vibration, chemical contamination, and corrosion.

Fuse holders determined to be exposed to stressors subject to aging effects will be visually inspected and tested at least once every 10 years. The first visual inspections and tests will be completed before the period of extended operation.

The specific type of test to be performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of metallic clamps of the fuse holders, such as thermography, contact resistance testing, or other appropriate testing.

This program will be implemented prior to the period of extended operation."

In LRA Section B2.1.20, "Fuse Holders Program," on Page B-48, the existing Program Description is replaced in its entirety with a new program description, to read as follows:

"Program Description

The Fuse Holders Program is a condition monitoring program that implements periodic visual inspections and tests on fuse holders in scope of License Renewal, located in passive enclosures and assemblies, and exposed to stressors that could affect circuit integrity if left unmanaged. The AMP for fuse holders (metallic clamps) manages the effects of aging from the following stressors, as applicable: fatigue, mechanical stress, vibration, chemical contamination, and corrosion.

Fuse holders are reviewed, inspected and/or tested to determine if they are exposed to stressors that could aversely affect circuit integrity (metallic connection with the fuse) if left unmanaged during the period of extended operation. A stressor could affect circuit integrity if it promotes loose connections from clip relaxation/fatigue (ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent removal/replacement of the fuse, or vibration), or if it exposes the fuse holder to chemical contamination or moisture that would promote corrosion and oxidation of the metallic fuse clips.

Fuse holders requiring aging management will be visually inspected and tested at least once every 10 years. The first visual inspections and tests will be completed before the period of extended operation.

The specific type of test to be performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of metallic clamps of the fuse holders, such as thermography, contact resistance testing, or other appropriate testing."

In LRA Section B2.1.20, "Fuse Holders Program," on Page B-49, the existing Operating Experience discussion is replaced with a new discussion, to read as follows:

"Operating Experience

The Fuse Holders Program is a new program, and, therefore, has no operating experience related to program implementation. A review of plant-specific operating experience was conducted, and no fuse connection failures from potential age-related causes were identified. The plant operating experience review did identify fuse enclosure issues involving water intrusion from event driven causes (e.g., water leaked into conduit and emptied into enclosure). These moisture intrusion events for enclosures exposed to this stressor could promote a corrosive condition for the metallic contact surfaces, leading to increased contact resistance and circuit failure if left unmanaged.

Inspections and testing (thermography) were performed on fuse holders in scope of License Renewal in terminal boxes. This initial inspection and testing revealed that some enclosures had significant signs of oxidation that could affect the circuit integrity if not repaired or reworked. The conditions were entered into the Corrective Action Program for disposition. For stressors, this program will ensure the integrity of fuse holders in scope of License Renewal and located in passive enclosures during the period of extended operation."

In LRA Section B2.1.20, "Fuse Holders Program," on Page B-49, the existing first sentence of "Conclusion" is replaced with a new first sentence, to read as follows:

"The Fuse Holders Program is a new program that implements periodic inspections and tests on fuse holders in scope of License Renewal, located in passive enclosures and assemblies, and exposed to stressors that potentially could challenge the electrical circuit integrity."

In LRA Table 3.0-3, "Electrical Service Environments," on Page 3.0-19, the last line item on the page (Mechanical Cycling) is deleted in its entirety and replaced with the following:

PINGP Environment	AMR Environment Group	Discussion
Stressors	Stressors	Fuse Holders (Metallic Parts - clips) exposed to the following stressors, if applicable: fatigue, mechanical stress, vibration, chemical contamination, and corrosion.

In LRA Section 3.6.2.1.7, on Page 3.6-7, under Environment, replace the two bullet items "Adverse localized environment (causing corrosion and/or fatigue)" and "Mechanical Cycling" with the single new bullet environment "Stressors."

In LRA Table 3.6.2-1, "Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation," on Page 3.6-20, for the line item "Fuse Holders (metallic parts) not part of a larger active assembly," replace the existing entries under Environment, "Adverse localized environment, Mechanical Cycling" with the new entry "Stressors."

RAI AMP-B2.1.22-1:

The GALL Report recommends that AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," is only applicable for steel (carbon steel) components to detect loss of material with the use of visual inspections. However, based on the applicant's program basis documents and AMR line items the staff noted that the applicant has expanded the scope of materials to include aluminum, brass and bronze, cast austenitic stainless steel, copper alloy, copper-nickel and stainless steel; and has expanded the scope of aging effects to include cracking due to stress corrosion cracking. The proposed expansion of AMP B2.1.22 is beyond the scope of GALL AMP XI.M38, which was meant for steel components and loss of material.

- Please justify why the expansion in the scope of materials to include additional metallic components and in the scope of aging effects to include cracking due to stress corrosion cracking are not considered enhancements to GALL AMP XI.M38.

- Please justify how this program will adequately manage the aging effect of loss of material and their associated aging mechanisms, as it applies to the additional metallic components added to the scope of this program.

- Identify and justify the inspection techniques used by this program that will be capable of detecting stress corrosion cracking for stainless steel components added to the scope of this program or please provide an appropriate program to manage cracking due to stress corrosion cracking for stainless steel components.

NSPM Response to RAI AMP-B2.1.22-1

Part A

The NUREG-1801, XI.M38 Program Description defines the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program as follows: "The program consists of inspections of the internal surfaces of steel piping, piping components, ducting, and other components that are not covered by other aging management programs." [emphasis added] Similarly, Element 1, Scope of Program, of the NUREG-1801 program description states: "The program visual inspections include internal surfaces of steel piping, piping elements, ducting, and components in an internal environment (such as indoor uncontrolled air, condensation, and steam) that are not included in other aging management programs for loss of material."

Consistent with this definition, PINGP has selected this NUREG-1801 program to manage loss of material in metallic components that are not included in other aging management programs (AMPs). Inclusion of other metallic materials was not considered an exception or an enhancement to NUREG-1801. In addition to steel components (i.e., carbon steel, stainless steel, galvanized steel), the scope of the PINGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes other metallic components made of cast iron, copper alloy, copper-nickel, aluminum, cast austenitic stainless steel, brass and bronze which are all managed for loss of material. Even though materials other than steel are not explicitly mentioned in NUREG-1801 for this program, the visual inspections conducted under this program are capable of identifying and managing loss of material for all components (steel and other metallic materials) within the scope of the program.

Additionally, the program manages cracking of the internal surfaces of stainless steel flexible connections in a diesel exhaust environment. Inspections for stress corrosion cracking will be performed by visual examination with a magnified resolution as described in 10 CFR 50.55a(b)(2)(xxi)(A) or with ultrasonic methods.

As indicated in the Standard Review Plan (SRP), enhancements are applicable to existing plant programs, and normally apply to the changes needed to bring an existing program into conformance with NUREG-1801. NUREG-1800, Page 3.0-3, Section 3.0.1 states: "In some cases, an <u>applicant may choose an existing plant program that does not currently meet all the program elements defined in the GALL</u> Report AMP. If this is the situation, the <u>applicant may make a commitment to augment the existing program</u> to satisfy the GALL Report AMP element prior to the period of extended operation. <u>This commitment is an AMP enhancement. Enhancements are revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation.</u> Enhancements include, but are not limited to, those activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP." [emphasis added] The SRP, in several locations, goes on to describe enhancements in the context of the NRC review as: "The LRA should identify any enhancements that are needed to permit an existing AMP to be declared consistent with the GALL Report AMP to which the LRA AMP is compared." The reviewer is to confirm "... that the enhancement, when implemented, would allow the existing plant AMP to be consistent with the GALL Report AMP ...." (Statement is typical of several. The specific example cited is from Section 3.2.2.1 on page 3.2-2). As identified in LRA Section B2.1.22, the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program is a new program being developed to be consistent with NUREG-1801, XI.M38, and, therefore, would not contain enhancements.

Part B

The program relies upon established visual examination techniques for the detection of loss of material due to corrosion and loss of material due to fouling. Inspections are performed at a frequency sufficient for the detection of aging effects prior to the loss of component intended function. The presence of corrosion or fouling on the internal surfaces of metallic materials will be identifiable as surface irregularities or localized discoloration. Surface irregularities include indications such as rust, scale/deposits, pitting, surface discontinuities, and coating degradation. For painted or coated surfaces, the visual inspections will confirm the integrity of the coating as a method to manage the effects of corrosion of the underlying metal surface. Inspection locations will be chosen to include conditions susceptible to the aging effects of concern (e.g., stagnant locations). Inspections are conducted on an ongoing basis at established intervals, to assure timely detection of degradation.

As described above, the visual inspections performed by this program are capable of identifying and managing the effects of corrosion and fouling in all the metallic materials in the scope of the program. The program is consistent with all of the elements in the NUREG-1801, Chapter XI, Program XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

Part C

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used to detect stress corrosion cracking only in the stainless steel flexible connections that are exposed to a diesel exhaust environment. Inspections for stress corrosion cracking will be performed by visual examination with a magnified resolution (i.e., capable of detecting a 1-mil width wire or crack) as described in 10 CFR 50.55a(b)(2)(xxi)(A) or with ultrasonic methods. Per ASME Section XI requirements, these examination methods are relied upon to detect cracking in Code Class 1 Reactor Coolant System pressure boundary components. Therefore, these same examination techniques are deemed to be sufficient for the detection of stress corrosion cracking in the diesel generator exhaust flex connections.

Visual and ultrasonic inspection activities are performed by personnel qualified in accordance with PINGP procedures and processes. Inspection results are documented in accordance with plant maintenance procedures. Scheduled maintenance and surveillance activities provide the capability for monitoring and trending of aging degradation. Inspection intervals are dependent on component material and environment, and take into consideration industry and plant specific operating experience. Results of the periodic inspections are monitored for indications of stress corrosion cracking. The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended functions.

Conclusion

Based on the discussion above, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is capable of managing loss of material and cracking in the components constructed of carbon steel, stainless steel, galvanized steel, cast iron, copper alloy, copper-nickel, aluminum, cast austenitic stainless steel, brass and bronze which are subject to the program.

RAI AMP-B2.1.26-1

The scope of the program in GALL Report AMP XI.E4 is to inspect all metal enclosed buses (MEBs) within the scope of the program and a sample of bolted connections. In LRA AMP B2.1.26, the applicant will only inspect representative samples of MEBs within the scope of license renewal.

The staff requests that the applicant explain how the scope of AMP B2.1.26 is consistent with that in the GALL Report AMP X1.E4.

NSPM Response to RAI AMP-B2.1.26-1

Per NUREG-1801, Program XI.E4, Elements 3 and 4, "A sample of accessible bolted connections will be checked for loose connection." To be consistent with NUREG-1801, Program XI.E4, LRA Sections A2.26 and B2.1.26 are hereby revised as follows:

In LRA Section A2.26, "Metal Enclosed Bus Program," on Page A-11, the first paragraph is revised by deleting the words "representative samples of" from the second line.

In LRA Section B2.1.26, "Metal Enclosed Bus Program," on Page B-57, the Program Description is revised in its entirety to read as follows:

> "The Metal-Enclosed Bus Program is a condition monitoring program that inspects the interiors of non-segregated 4160V phase bus between station offsite source auxiliary transformers and plant buses. Internal visual inspection is performed to observe signs of aging of the bus insulation materials such as cracking and discoloration, evidence of loose connections, and signs of moisture and debris intrusion. Internal bus supports are visually examined for structural integrity and signs of cracks. The inspection may also include thermography and/or electrical resistance testing to ensure the integrity of bus connections. The program manages the aging effect of reduction of insulation resistance in insulation components, loose connections, and corrosion from moisture/debris intrusion in non-segregated bus ducts.
>
> The scope of the Metal-Enclosed Bus Program applies to MEB within the scope of license renewal. The internal portion of the MEB will be visually inspected every 10 years. For bolted connections, a sample of accessible bolted connections will be

checked for loose connection by thermography, resistance measurement, or by an alternative internal bolted connection visual inspection to detect surface anomalies of the insulating material covering the connection. If selected, the loose connection thermography or resistance measurement will be performed every 10 years, or if selected, an alternative internal bolted connection visual inspection will be performed every 5 years. The first inspections and tests will be completed before the period of extended operation."

RAI AMP-B2.1.26-2

The GALL Report AMP XI.E4 will inspect the interior of MEBs and the Structure Monitoring Program will inspect the exterior of the enclosure assembly. In LRA AMP B2.1.26, under program element 3 (parameters monitored/inspected), the applicant stated that it will inspect both the exterior and interior of MEBs such as housing and housing seal.

The staff requests that the applicant explain why this is not an exception to the GALL Report XI.E4 or provide a technical basis for this exception.

NSPM Response to RAI AMP-B2.1.26-2

As stated in LRA Section B2.1.38, the Structures Monitoring Program performs periodic Metal Enclosed Bus (MEB) inspections to monitor the exterior condition of the enclosure assembly steel and elastomers. Both the PINGP MEB Program and the Structures Monitoring Program (with enhancement) are consistent with GALL. As a general rule, including activities in an aging management program, which exceed the minimum standards for that program in NUREG-1801, would not be considered an exception to NUREG-1801.

However, for clarity, the Program Basis Document for the MEB Program has been revised to delete external inspection statements from its scope.

RAI AMP-B2.1.26-3

Under element 3 (parameter monitored/inspected), the GALL Report XI.E4 states that the internal bus support will be inspected for structural integrity and signs of cracks.

The staff requests that the applicant explain why the internal bus supports are not included in this element for LRA AMP B.2.1.26.

NSPM Response to RAI AMP-B2.1.26-3

As stated in PINGP LRA Appendix B2.1.26, the Metal-Enclosed Bus Program includes visual inspection of the internal bus supports for structural integrity and signs of cracks. The Program Basis Document for MEB has been revised to explicitly list the inspection of internal bus supports for structural integrity and signs of cracks in the discussion for Element 3. This is consistent with NUREG-1801, Chapter XI, Program XI.E4, Element 3.

RAI AMP-B2.1.26-4

Under program element 6 (Acceptance Criteria) of LRA AMP B.2.1.26, the applicant stated that the acceptance criteria for each inspection and test is defined by the specific type of test performed.

The staff requests that the applicant describe acceptance criteria for each inspection and/or test. Compare these acceptance criteria against those in GALL XI.E4 element 6.

NSPM Response to RAI AMP-B2.1.26-4

The Program Basis Document for the Metal Enclosed Bus Program has been revised to clarify the intent of the acceptance criteria.

The thermography inspection acceptance criterion for bolted connections is to maintain temperatures below the maximum allowed temperature for the application.

When resistance measurement is performed, a low resistance acceptance value is used, appropriate for the application. MEB manufacturer design information, if available, may be used as a basis for acceptance criteria.

For the alternative internal bolted connection visual inspection, the acceptance criteria for insulated bolted connections are to be free from unacceptable visual indications of surface anomalies which suggest that conductor insulation degradation exists. When the alternative visual inspection for bolted connections is used, the absence of discoloration, cracking, chipping or surface contamination will provide positive indication that the bolted connections are not loose.

For the internal visual inspection, the acceptance criteria would be no unacceptable indication of corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion. Internal bus supports are visually inspected for indication of reduced structural integrity and signs of cracks. An unacceptable indication is defined as a noted condition or situation that, if left un-managed, could lead to a loss of intended function.

The acceptance criteria described above are consistent with NUREG-1801, Chapter XI, Program XI.E4, Element 6, Acceptance Criteria.

RAI AMP-B2.1.36-1:

In LRA Section B2.1.36, "Selective Leaching of Material Program," the applicant proposed an exception to the recommendations of GALL AMP XI.M33, "Selective Leaching of Materials." The exception proposed alternative selective leaching detection techniques that may be used instead of, or in addition to, visual inspection and hardness testing. The staff requests that the applicant provide additional information concerning the proposed alternative detection techniques and justification for using the proposed techniques.

NSPM Response to RAI AMP-B2.1.36-1

NUREG-1801 specifies only visual inspection and hardness testing to detect selective leaching. Visual inspection and hardness measurement may not be feasible due to component form, configuration and location (i.e., heat exchanger tubes). In addition, other available detection techniques (e.g., mechanical scraping, chipping), and additional examination methods that become available to the nuclear industry, may be shown to be at least as effective as visual inspection and hardness testing in detecting and assessing the extent of the selective leaching mechanism. The one-time examinations will determine whether selective leaching has occurred, and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation.

When selective leaching occurs in gray cast iron components, the iron is dissolved leaving behind a porous mass, consisting of graphite, voids and rust. This is known as graphitization. Selective leaching in copper alloys (>15% Zinc) occurs when zinc is dissolved in the liquid solution that comes in contact with the copper alloy component. When the zinc is removed a weakened and corroded structure is left behind. This is known as dezincification. A combination of visual inspections in conjunction with mechanical methods will result in the detection of selective leaching, if present. The visual inspection is capable of detecting corrosion while the mechanical methods of chipping and scraping are capable of detecting a corroded or weakened component structure. If these methods detect dezincification or graphitization then a follow-up examination or evaluation will be performed. The examination or evaluation may require confirmation of selective leaching with a metallurgical evaluation (which may include a microstructure examination). If selective leaching is occurring, the condition will be entered into the Corrective Action Program for evaluation to determine acceptability of the affected components for further service, and assessment of required corrective actions.

RAI AMP-B2.1.38-1

The PINGP LRA AMP B2.1.38, "Structures Monitoring Program," does not clearly specify how the GALL Report program element "Parameters of Aging Effects" is met. The staff notes that under "Enhancements" to this program element, it states to "require periodic sampling of groundwater...to ensure they remain non-aggressive."

The staff requests that the applicant provide the following information:

(a) The location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations; and

(b) Explain the technical basis for concluding that "periodic sampling" of a single well is sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater.

NSPM Response to RAI AMP-B2.1.38-1

Part (a)

Water samples are taken from the plant's two deep wells and from the Mississippi River adjacent to the Intake Screenhouse. The deep wells are located approximately 295 yards and 350 yards west of the safety-related and important-to-safety concrete foundations. The river water sampling location is the Mississippi River just east of the Intake Screenhouse, approximately 210 yards from the safety-related and important-to-safety concrete foundations. The locations of the two wells and the Intake Screenhouse are provided on License Renewal boundary drawing LR-193817, at coordinates B4, D4 and C9, respectively.

Part (b)

Periodic groundwater chemistry sampling is taken from two wells located west of the safety-related and important-to-safety concrete foundations. Water from the Mississippi River in the vicinity of the plant is also tested since it would be an indicator of the chemistries of surface water runoff into the river and chemical intrusion into the groundwater. Test results from well and river water sampling points have continuously shown that concentrations of sulfates and chlorides are significantly lower than the NUREG-1801 threshold indicators for an aggressive environment of 1500 ppm and 500 ppm respectively. Test results include a preconstruction report in 1965 and reports spanning a 22-year period (from 1984 to 2006) which indicate that the maximum sulfates and chlorides levels recorded are 119 ppm and 89.4 ppm respectively, and therefore the groundwater is not aggressive. Likewise, pH data obtained over the same time period ranges from 7.6 to 8.5 compared to the GALL indicator for an aggressive pH of 5.5 and less (Reference LRA Section 3.5.2.2.2.2.4). These non-aggressive chemistries are what would be expected since industries in the county where the plant resides are not typically associated with those that would have a deleterious effect on concrete (such as the effect of acid rain from a fossil fuel burning plant). The U. S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common pollutants: nitrogen dioxide, sulfur dioxide, carbon monoxide, lead, ozone, and particulate matter, and has designated all areas of the United States as having air quality better ("attainment") or worse ("non-attainment") than the NAAQS. As discussed in Section 2.4 of the PINGP LRA Environmental Report, the region where PINGP resides is in attainment for all criteria pollutants. Therefore the air quality is better than the NAAQS. Farm land adjacent to the plant could introduce agricultural-related constituents (fertilizer, pesticides, herbicides) into the groundwater, but constituent concentrations would be diluted and occur only seasonally, and, therefore, would not be expected to have any significant impact on the concrete foundations.

RAI AMP-B2.1.38-2

The PINGP LRA AMP B2.1.38, "Structures Monitoring Program," does not clearly specify how the GALL Report program element "Operating Experience" is met. PINGP has identified leakage of boron water from both units' refueling cavities and through the concrete backing the refueling cavity liners since 1998. Leakage was fairly consistent throughout the duration of the flooding of the refueling cavity pool (average 1 gallon per hour). Since then, the leakage path has not been specifically identified. Leakage could potentially degrade the carbon steel containment vessel, containment concrete, and containment rebar.

The staff requests that the applicant provide the results of any root cause analyses, as well as corrective and preventive actions taken to address or correct this issue.

NSPM Response to RAI AMP-B2.1.38-2

Concrete structures inside the Unit 1 and 2 containment vessels are managed by the Structures Monitoring Program (SMP). The Unit 1 and 2 containment vessels are managed by the ASME Section XI, Subsection IWE Program. Operating experience has been effective in monitoring and detecting conditions that have the potential for degradation, such as the leaks inside the Unit 1 and 2 containment vessels observed during refueling activities. The condition was detected by the ASME Section XI, Subsection IWE Program while examining the Class MC pressure retaining vessel. Both programs took corrective action to address the leakage.

The following discussion of the leakage inside containment includes the history of the degradation, the identification of root causes, the ongoing corrective actions to mitigate the leakage, the current status of the condition, and future corrective actions being considered. Sketches that illustrate containment sump locations and concrete pour configurations, referenced in the discussion below, are provided in Enclosure 3. The sketches are specifically from Unit 2, but are representative of Unit 1.

Leakage inside containment was first documented in 1998 during the Unit 2 refueling outage with water observed entering sump B from cracks in the grout around the RHR suction penetration sleeves at elevation 694'-10". This area is grouted from the floor of the sump to the ceiling of the sump back to the containment vessel wall. Containment walkdowns also detected leakage at the basement level of containment elevation 697'-6" outside the north wall for the Reactor Coolant (RC) Drain Tank cubicle. In 1999 during the Unit 1 refueling outage, leakage was detected at sump B, the sloped wall behind the RC Drain Tank, the ceiling above the regenerative heat exchangers, the RCP vault, and the nuclear instrument detector (NIS) adjacent to the 12 accumulator on elevation 715'.

When the leakage was first documented in 1998, the fluid was chemically analyzed to help identify its source. The chemical analysis of the fluid determined it to be similar to refueling water with a boron concentration of 2700 ppm, chloride concentration of 7 ppm, sulfate concentration of 0.2 ppm, and pH of 7.8. The boron content of the refueling pool water was measured at 2700 ppm and a pH of 5.2. The increase in pH from the refueling cavity water to those found at the leaks was attributed to the acidity being neutralized by the carbonates and other minerals in the concrete. Water chemistry results taken at the RC Drain Tank floor area were similar except that the boron concentration was 5329 ppm. This higher level was attributed to residual boron in the area from staining observed on the adjacent wall. Grout at sump B was removed to inspect the containment vessel wall revealing no degradation. Other potential sources of leakage such as the RC, Safety Injection (SI) and Residual Heat Removal (RH) systems were investigated and no other feasible source of leakage was identified. Leakage in containment occurs only when the refueling cavity pool is flooded and stops when the refueling cavity is drained.

With the leakage source fairly well established, the stainless steel reactor cavity liner was tested for faulty welds. Where leaks were found, repairs were made for both units. In addition to liner weld leaks, other leak points were investigated including the sand plug covers and bolts, neutron detector covers and bolts, fuel lifting device bolts and baseplates, and other liner attachments. A number of areas were not inspected due to inaccessibility and other areas were inspected on a limited basis due to equipment blocking access to the area.

The effects of the Unit 2 refueling cavity leakage on containment concrete were evaluated by an outside engineering consultant, Automated Engineering Services Corporation (AES). Their report is summarized as follows:

A review of available literature shows that boric acid solutions should not degrade the cement or concrete itself. Such degradation requires much stronger acids such as sulfuric acid with lower pH values. Refueling water has a pH of 5.2. The primary flow path for the leakage is through construction joints between concrete pours where there is no rebar. Concrete wall rebar and embedded support steel for heavy equipment can potentially cross construction joints if located adjacent to these joints. The concrete pours are connected using a keyed tongue-and-groove joint. Reaction with carbonates in the concrete neutralizes the acidity in the solution such that the pH of the leaking fluid becomes neutral or slightly alkaline as determined through chemical evaluations. The short duration of the wetting which occurs only during refueling is a mitigating factor in any analysis of potential deleterious effects. If you were to assume that some leakage does in fact flow through cracks in the concrete and comes into contact with rebar, the low temperatures and concentrations of boric acid in this environment are not conducive to significant corrosion since boric acid does not cause particularly aggressive corrosion below 180 degrees Fahrenheit. Laboratory tests indicate that aerated solutions of 2000 ppm boric acid at 100 degrees F cause only between 2 and 5 mils of corrosive material loss per year (Reference: Portland Cement Association Concrete Information, "Effects of Substances on Concrete and Guide to Protective Treatments," IS001, 1997). The duration of the corrosion resulting from refueling activities is limited. Clearly, after the refueling cavity has been drained, no more acid will be supplied to the affected region, and once the existing acid is consumed, the reaction will stop. Whether the environment remains wetted or not may be inconsequential in light of the fact that there is no longer a continuous supply of boric acid. The absence of a continuous supply of boric acid and the neutralizing effect of cement on the pH of the fluid make it reasonable to conclude that it is very unlikely that significant corrosion of the concrete reinforcing bar from refueling cavity leakage will occur. It can be instructive to consider a closely analogous situation. For instance, the RPV flange surface into which the closure studs are threaded is composed of manganese-molybdenum steel which is quite susceptible to boric acid corrosion under the right conditions. However, this very important component surface is left exposed to the refueling cavity water for the duration of refueling operations, under aerated conditions, with no compensatory measures required.

AES postulated that the leakage paths to sump B were through horizontal and vertical construction joints, most probably between the 4th and 5th concrete pours for horizontal travel and up through the vertical joint between the containment steel and the adjacent sloping concrete wall. As for the leakage to the RC Drain Tank area, the possible flow path could be through the joint between the internal concrete wall and the steel containment shell, and then through the horizontal construction joint between the wall and the floor slab (pour 5). These construction joints do not have reinforcing steel across them; rather they are keyed tongue-and-groove joints formed during the concrete pours, or they have the previous pour surface roughened and coated by a bonding compound prior to the installation of the next pour. Therefore, reinforcing steel is not subjected to potential adverse action of the borated water. When concrete wall reinforcing steel and embedded support steel for heavy equipment are located in the vicinity of a construction joint, they can potentially cross these joints. The lack of deterioration of the concrete surfaces where white deposits were seen further reinforces the position that borated water does not have an appreciable effect on concrete. In view of the above information, it was concluded that the internal concrete surfaces at the construction joints and in the flow paths of the borated leaks would not have any deterioration and should be capable of performing their intended function. As for the reinforcing bars, since the borated water does not affect the concrete surface and the chloride content is very low, they would be fully protected inside the concrete. Based on this observation, there is no reason to suspect corrosion of the reinforcing bars and therefore the strength of the reinforced concrete is not compromised by the borated water leaks.

As for the effects of borated water on the steel containment, it is known in the nuclear industry that borated water in the form of boric acid can be corrosive to components fabricated from carbon and low alloy steels, however most studies involved reactor coolant at high concentrations (13,000 – 15,000 ppm of boron with small amounts of lithium) and at high temperatures (>200 degrees F). The publication entitled, "Boric Acid Corrosion of Carbon and Low Alloy Steels," Corrosion 94, by C.A. Campbell, S. Fyfitch, and D. T. Martin, as part of The Annual Conference and Corrosion Show sponsored by NACE International, concludes that the maximum corrosion rates occurred where moisture can be replenished by a flowing solution, keeping a wet/dry interface between the solution and the dry boric acid crystals. It was also seen that when the boric acid dries out and is not significantly re-wetted, the corrosion levels are much lower. The exposed steel containment surface beneath the removed grout in sump B did not show any signs of corrosion or surface pitting. This provided strong evidence that the boric acid solution was weak enough and was not constantly wetted for a long enough period of time to cause any deterioration of the steel surface. The same conclusion can be extended to other plate surfaces which are not exposed and which may be in the leak paths.

The Unit 2 leakage evaluation by AES in 1998 concluded that the effect of borated water leaks on structural materials was very minimal and would not affect the capability of the structure to perform its intended function. The AES evaluation formed the basis for the plant evaluation of the leakage observed during the 1999 Unit 1 outage.

With a few exceptions, leaks continued to be identified during refueling outages. In more recent outages, leakage was significantly reduced when leak points in the refueling cavity liner were properly and thoroughly sealed. Action taken over the years to help eliminate leakage included coating suspected leak points with a spray-on sealer. This method was not completely successful due to the difficult application process and procedure inadequacies. The most recent methods to mitigate the leakage include caulking the refueling cavity bolted connections and baseplates, and ensuring that the sand plug and NIS covers are properly and securely installed. Again this method was not completely successful due to installation difficulties in a radiological environment. New procedures were developed and others revised to facilitate the difficult installation processes.

Grout was removed in 2002 around the RHR pipe sleeves in sump B to inspect the Unit 1 containment vessel steel similar to the action taken in 1998 during the Unit 2 outage. Some discoloration around penetrations C30A and C30B was detected; however no degradation of the penetrations or steel vessel was observed. Absent any degradation, no further action was taken in accordance with ASME Section XI, Subsection IWE.

Plant evaluations of leakage since 1998 continue to show no evidence of deterioration at the containment vessel sump B location. Evaluations continue to cite the conclusions reached by AES in 1998, and in their reevaluation in 2006, which concluded that the

1998 evaluation was still valid and the integrity of the concrete, reinforcing bars, and the containment vessel plate had not been compromised.

During the Unit 2 outage in 2008, the plant performed over 150 ultrasonic (UT) thickness readings of the containment vessel from its exterior surface in the vicinity of the fuel transfer tube and at the sump B location. Access to the exterior surface of the containment vessel is reached from inside the shield building which completely encloses the vessel. An annular space of approximately five feet between the structures allows for easy access to the containment vessel exterior surface. All readings were found to exceed the nominal vessel plate thicknesses of 1 ½" and 3 ½". In addition, plant personnel removed grout and reinspected the containment vessel at sump B. No evidence of corrosion or pitting was found.

In conclusion, numerous examinations have been conducted to identify all potential leak paths in the refueling cavity liner. The condition has not been completely mitigated over the years; measurable leakage has been detected during most refueling outages. Leakage mitigation appeared to be linked to the ability to completely seal leak points in the refueling cavity. With numerous liner attachments and welds, and with areas difficult to access, the process of identifying and properly sealing leak paths has been proceeding methodically, aided by knowledge gained along the way. It is now known that nuclear instrument detector covers and sand plug covers were often the source of leakage, with improper torquing of closure bolts identified during one outage, and a misaligned gasket identified during another outage. Procedures detailing the step-by-step process for caulking the covers have been developed, and specific caulking material requirements have been identified. It is also now known that a step in the procedure for caulking non-removable nuts was subject to misinterpretation, and the step was rewritten to provide clarity. No evidence of containment vessel degradation has been detected based on vessel wall examinations and UT thickness readings in areas expected to be the most susceptible to degradation, and no evidence of concrete degradation has been identified during inspections.

NSPM will continue to evaluate the leakage in accordance with the ASME Section XI, Subsection IWE Code requirements and the Structures Monitoring Program. This issue remains open within the plant Corrective Action Program for the determination of additional actions to be taken.

RAI AMP-B2.1.40-1

During audit of site documents related to LRA AMP B2.1.40, Water Chemistry Program, it was noted that there are differences between the water chemistry diagnostic parameter measurements recommended in EPRI Water Chemistry Guidelines referenced in the GALL Report for AMP XI.M2, Water Chemistry, and diagnostic parameter measurements as implemented by the applicant's water chemistry-related procedures. However, these differences were not identified as exceptions in the LRA's description of the Water Chemistry Program.

Please explain why the differences from the recommendations in the EPRI Water Chemistry Guidelines were not identified in the LRA as exceptions to the recommendations in the GALL Report and justify that with these differences the PINGP Water Chemistry Program provides adequate aging management for affected components during the period of extended operation.

NSPM Response to RAI AMP-B2.1.40-1

The PINGP Water Chemistry Program conforms to both the EPRI "PWR Primary Water Chemistry Guidelines" and the EPRI "PWR Secondary Water Chemistry Guidelines." PINGP procedures require water chemistry control in accordance with Revision 5 of the "PWR Primary Water Chemistry Guidelines," EPRI TR-1002884, for primary and auxiliary water systems; and Revision 6 of the "PWR Secondary Water Chemistry Guidelines," EPRI 1008224, for secondary water systems.

The PINGP Water Chemistry Program includes EPRI control and diagnostic parameters. Control parameters are defined as those which require strict control due to material integrity considerations. Diagnostic parameters are those which provide assistance in interpreting chemistry variations, or may affect radiation field buildup, corrosion performance or fuel integrity. Where published data does not justify treating a parameter as a control parameter, it is included in the guidelines as a diagnostic parameter. Though deviations to diagnostic parameters are discussed in the Program Basis Document for the PINGP Water Chemistry Program, only deviations from EPRI control parameters have been identified as exceptions to NUREG-1801. As a result, the diagnostic parameter deviations were not identified as exceptions in the PINGP LRA.

This position is supported by the definitions of control and diagnostic parameters in the EPRI Water Chemistry Guidelines, as illustrated by the following excerpts:

- EPRI TR-1002884, "PWR Primary Water Chemistry Guidelines," Volume 1, Section 3.3, Control and Diagnostic Parameters, states:

  "Primary chemistry guideline parameters are divided into two categories as defined below:

  - Control Parameters are those parameters which require strict control due to material integrity considerations. Some of these parameters are also addressed in individual plant Technical Specifications.

  - Diagnostic Parameters are those parameters which assist the chemistry staff in interpreting primary coolant chemistry variations, or which may affect radiation field buildup, corrosion performance of system materials, or fuel integrity."

- EPRI 1008224, "PWR Secondary Water Chemistry Guidelines," contains the following discussions:

  Section 4.4.10, Documenting Exceptions to Diagnostic Parameters

  > "Chapters 5 and 6 identify several chemical parameters that have been characterized as diagnostic. The purpose of designating these as diagnostic is that they can be of assistance when off-normal chemistry conditions exist since they may provide insight to the cause of the off-normal condition."

  Section 5.2, Control and Diagnostic Parameters

  > "The tables presented in this chapter include chemistry monitoring requirements and recommendations. Some of these are titled Control Parameters (requirements) and some Diagnostic Parameters (recommendations).
  >
  > Control Parameters are those parameters that have a demonstrated relationship to steam generator degradation. Plant operations should support actions required to maintain these parameters within the specified values.
  >
  > Diagnostic Parameters are important to monitor the program effectiveness, identify programmatic problems, or assist in problem diagnosis."

  Section 6.2, Control and Diagnostic Parameters

  > "The tables presented in this chapter include surveillance parameter requirements and recommendations. Some of these are titled Control Parameters (requirements) and some Diagnostic Parameters (recommendations).
  >
  > Control Parameters are those parameters that have a demonstrated relationship to steam generator or turbine degradation. Plant operations should support actions required to maintain these parameters within the specified values. Control parameters are assigned Action Level values.
  >
  > Diagnostic Parameters are employed to monitor program effectiveness and/or to identify programmatic problems. Diagnostic Parameters do not have assigned values/limits."

NUREG-1801, Program XI.M2, Water Chemistry, Element 1, states: "The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines..." As stated in the EPRI guideline citations provided above, parameters which require strict control due to material integrity considerations, and are therefore needed to manage the effects of aging, are the

Control Parameters. However, the Diagnostic Parameters are only those which provide assistance in interpreting chemistry variations, or may affect radiation field buildup, corrosion performance or fuel integrity, are not required for aging management and, therefore, are not within the scope of the NUREG-1801, XI.M2 program.

The PINGP Water Chemistry Program manages aging effects by controlling concentrations of known detrimental chemicals species below action level (or control parameter) limits known to cause degradation. The program has been effective in monitoring and controlling primary, secondary, and auxiliary water chemistry, and taking required actions to address out-of-specification values.

RAI AMP-B2.1.40-2:

Section B2.1.40 of the LRA states that the "monitoring and trending" program element of the existing Water Chemistry Program will be enhanced to require increased sampling to be performed as needed to confirm the effectiveness of corrective actions taken to address an abnormal chemistry condition. The description in the LRA provides insufficient information for the staff to evaluate the need for or the effectiveness of the proposed Water Chemistry Program enhancement.

Please explain what the current practices and procedural requirements are with regard to increased chemistry sampling after corrective actions are taken to address an abnormal chemistry condition.

NSPM Response to RAI AMP-B2.1.40-2

NUREG-1801, Chapter XI, Program XI.M2, Water Chemistry, Element 5, Monitoring and Trending states: "Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions." The proposed Water Chemistry Program enhancement cited on Page B-81 of the PINGP LRA is needed to formally proceduralize the requirement to utilize increased sampling following an abnormal chemistry condition at PINGP, since this NUREG-1801 recommendation is not explicitly stated in the current PINGP chemistry procedures.

Consistent with NUREG-1801, Program XI.M2, Element 7, Corrective Actions, the PINGP Water Chemistry Program requires that when limits are not met, results are documented, Operations is notified, the condition is evaluated, and corrective actions are taken to restore parameters to their expected range within the time period specified in the EPRI water chemistry guidelines. Current PINGP sampling procedures specify the following actions in response to an out-of-specification chemistry condition:

1. Notify the Control Room and Chemistry Management of the condition.
2. Perform a backup analysis to confirm results.
3. Obtain a new sample and conduct another analysis.
4. Implement appropriate corrective actions in accordance with procedures.
5. Document the condition in the Corrective Action Program.

6. Perform a technical review to address the cause, corrective action(s), effect on plant operation, and consequence of the condition. (This action is the responsibility of Chemistry Management personnel.)

The need to conduct increased sampling is presently implemented via the PINGP Chemistry History and Records Management Software (CHRMS). Through use of the software package, Chemistry Management may require special or additional sampling. These special sampling requirements are communicated and implemented through the issuance of the "Chemistry Managers Special Sampling Report."

RAI AMP-B2.1.40-3:

Section B2.1.40 of the LRA states an exception to the "acceptance criteria" program element of GALL AMP XI.M2, Water Chemistry. The exception states that primary water (reactor coolant) dissolved oxygen Action Level limits are consistent with the Technical Requirements Manual, but above the corresponding recommended EPRI guideline limits. The information in the LRA is insufficient for the staff to evaluate the acceptability of this exception.

Please provide a quantitative comparison of the dissolved oxygen Action Level limits in your Technical Requirements Manual against the corresponding recommended EPRI guideline limits, and provide a technical justification of why the limits in your Technical Requirements Manual provide acceptable aging management mitigation during the period of extended operation that is comparable to what is provided by the EPRI guideline limits.

NSPM Response to RAI AMP-B2.1.40-3

At PINGP, the dissolved oxygen Action Level limit for primary water during power operation (Mode 1) is specified consistent with the PINGP Technical Requirements Manual, and above the corresponding EPRI PWR Primary Water Chemistry Guidelines limit. This was identified as an exception to NUREG-1801, XI.M2, Element 6, Acceptance Criteria.

A quantitative comparison of the primary water dissolved oxygen Action Level limits (for Mode 1, Power operation) found in the PINGP Technical Requirements Manual (TRM) and the EPRI PWR Primary Water Chemistry Guidelines (1002884, Revision 5) is provided below. The corresponding Action Level limits contained in the PINGP implementing procedure are also shown.

Reactor Coolant (RC) System Dissolved Oxygen Action Level Limits

Source	Action Level 1	Action Level 2	Action Level 3
PINGP Technical Requirements Manual, Section 3.4.1 (Modes 1, 2, 3, & Mode 4 w/ RCS ≥250 °F.)	---	Limit A <100 ppb (Restore parameter within 24 hours[1])	Limit B <1000 ppb (Unit shutdown to Mode 3 in 6 hours and Mode 5 in 36 hours)
EPRI 1002884, Table 3-3 (Power operation, Reactor critical)	>5 ppb (Restore parameter within 7 days)	---	>100 ppb (Initiate orderly shutdown immediately)
PINGP Implementing Procedure (Power operation, Mode 1)	>5 ppb (Restore parameter within 7 days)	>100 ppb (Restore parameter within 24 hours[2])	>1000 ppb (Initiate orderly shutdown immediately)

[1] If the parameter has not been restored to within the Action Level 2 (TRM Limit A) limit within 24 hours, the Unit shall be in Mode 3 in 6 hours and Mode 5 in 36 hours.
[2] If the parameter has not been restored to within the Action Level 2 limit condition within 24 hours, an orderly Unit shutdown should be initiated.

As evidenced by the comparison provided above, the difference in the Action Level 3 limit (i.e., 1000 ppb in TRM vs. 100 ppb in EPRI) and the 24-hour restoration period allowed by the TRM were the reasons for the NUREG-1801, XI.M2, Acceptance Criteria exception for dissolved oxygen. These acceptance criteria have been in place at PINGP since initial operation, and are the same limits that were specified in the original PINGP Technical Specifications. The Reactor Coolant System chemistry limits have since been removed from Technical Specifications and relocated to the PINGP Technical Requirements Manual.

After reviewing this issue, NSPM has decided to revise the Water Chemistry Program and remove the exception. Consequently, the License Renewal Application, B2.1.40, Water Chemistry Program is being changed to add an enhancement to the program for "Acceptance Criteria" to require Reactor Coolant System dissolved oxygen Action Level limits to be in accordance with the EPRI Guideline limits for Reactor Coolant System Power Operation Control Parameters. In addition, the Exception to NUREG-1801, Acceptance Criteria, for PINGP primary water dissolved oxygen Action Level limits being above the corresponding EPRI guideline limits, is removed. The associated LRA changes are as follows:

In LRA Section B2.1.40 on Page B-80, under Exceptions to NUREG-1801, the first paragraph under the second bullet "Acceptance Criteria", concerning primary water dissolved oxygen, is hereby deleted.

In LRA Section B2.1.40 on Page B-81, under Enhancements, a new second bullet is hereby added to read as follows:

- "Acceptance Criteria

  The program will be enhanced to require Reactor Coolant System dissolved oxygen Action Level limits to be consistent with the limits established in the EPRI PWR Primary Water Chemistry Guidelines."

To reflect this new enhancement, Commitment Number 32 contained in the Preliminary License Renewal Commitment List included in the LRA transmittal letter dated April 11, 2008, is hereby revised to read as follows:

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
32	The Water Chemistry Program will be enhanced as follows: • The program will require increased sampling to be performed as needed to confirm the effectiveness of corrective actions taken to address an abnormal chemistry condition. • The program will require Reactor Coolant System dissolved oxygen Action Level limits to be consistent with the limits established in the EPRI "PWR Primary Water Chemistry Guidelines."	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.40

A review of operating data for both PINGP Units for the last 10 years verified that the Action Level 1 limit of 5 ppb for Reactor Coolant System dissolved oxygen was not exceeded during power operation. Typical plant values for oxygen and other control parameters are well below EPRI limits. Consistent with EPRI guidelines, minimum primary water hydrogen levels are maintained which are effective in mitigating oxidizing conditions due to radiolysis or oxygen ingress to the reactor coolant. Therefore, the Water Chemistry Program has been effective in controlling plant chemistry and providing reasonable assurance that aging effects are being managed.

RAI AMP-B3.1-1.

The GALL Report AMP X.E1 program element "Scope of Program," states that this program applies to certain electrical components that are important to safety and exposed to harsh environment accident conditions. In PINGP AMP B3.1 under element

1, the applicant states that the AMP consists of PINPG activities that manage aging effects of the electrical cables and connections subject to 10 CFR 50.49 EQ requirements.

The staff requests that the applicant explain how the scope of program B3.1 is consistent with that in the GALL Report AMP X.E1.

NSPM Response to RAI AMP-B3.1-1

As stated in PINGP LRA Section B3.1, the scope applies to certain electrical components subject to Environmental Qualification (EQ), and the guidance provided in Regulatory Guide 1.89, Revision 1. This is consistent with the program scope identified in NUREG-1801, Chapter X, Program X.E1, Element 1. The PINGP EQ Program is consistent with the recommendations of NUREG-1801, Chapter X, Program X.E1, Environmental Qualification (EQ) of Electrical Components. The PINGP Program Basis Document for the Environmental Qualification (EQ) of Electrical Components Program does not intend to restrict the program to cables and connections.

To clarify the description of the EQ Program, the LRA is hereby revised as follows:

In LRA Table 3.6.2-1, "Electrical Components - Electrical Commodity Groups - Summary of Aging Management Evaluation," on Page 3.6-19, the first Component Type row entry for EQ is replaced to read as follows:

> "Electrical Components Subject to 10 CFR 50.49 Environmental Qualification Requirements"

RAI AMP-B3.1-2.

The GALL Report AMP X.E1 under program description discusses reanalysis attributes in detail. In LRA Section B3.1, the applicant did not describe the reanalysis attributes in the program description of PINGP AMP B3.1.

The staff requests that the applicant provide a detailed description of each of the reanalysis attributes.

NSPM Response to RAI AMP-B3.1-2

A detailed description of the reanalysis attributes of the EQ Program was provided in PINGP LRA Section 4.4.1. For completeness, this description is also being incorporated into the program description. On LRA page B-83, Section B3.1, Environmental Qualification (EQ) of Electrical Components Program, the following information is hereby added to the end of the existing Program Description:

> "Analytical Methods - The PINGP EQ Program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied for the current

evaluation. Arrhenius methodology is an acceptable model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For License Renewal, acceptable methods for establishing the 60-year normal radiation dose includes multiplying the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years) or using the actual calculated value for 60 years. The result is added to the accident radiation dose to obtain the total integrated dose for the component.

Data Collection and Reduction Methods - Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the primary method used for a reanalysis per the EQ Program.

Underlying Assumptions - EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action - The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is maintained, replaced, or re-qualified prior to exceeding the period for which the current qualification remains valid."

RAI AMP-B3.1-3.

The LRA Appendix A, FSAR Supplement Section A3.0, did not provide a complete summary of the time-limited aging analysis (TLAA) evaluation of the environmental qualification of electric equipment as described in SRP Section 4.4, Table 4.4-2.

The staff requests that the applicant provide a complete summary of the TLAA evaluation of the EQ of electrical equipment program.

NSPM Response to RAI AMP-B3.1-3

In LRA Section A3.1, Environmental Qualification (EQ) of Electrical Components Program, on Page A-17, the following paragraph is hereby added to the end of the existing program description, to read as follows:

"Reanalysis is an acceptable alternative for extending the qualified life of an EQ component. Important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met)."

Enclosure 2

NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

6 Pages

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

The following line items are hereby incorporated into LRA Table 3.3.2-11 to reflect the addition of piping and components into the scope of License Renewal as discussed in the response to RAI 2.1-2. The existing line items in Table 3.3.2-11 are unaffected by this change.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Bolting / Fasteners	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-2	3.3.1-89	A
Bolting / Fasteners	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - General Corrosion	Bolting Integrity Program	VII.I-4	3.3.1-43	B
Bolting / Fasteners	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Preload - Thermal, gasket creep, loosening	Bolting Integrity Program	VII.I-5	3.3.1-45	B, 304
Heaters	Pressure Boundary	Copper Alloy	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-12	3.3.1-88	C
Heaters	Pressure Boundary	Copper Alloy	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-3	3.3.1-82	E, 320
Heaters	Pressure Boundary	Copper Alloy	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-3	3.3.1-82	E, 320
Heaters	Pressure Boundary	Copper Alloy	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-3	3.3.1-82	E, 320
Heaters	Pressure Boundary	Copper Alloy	Raw Water (Int)	Loss of Material - Selective Leaching	Selective Leaching of Materials Program	VII.C1-4	3.3.1-84	B, 320
Piping / Fittings	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Piping / Fittings	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Piping / Fittings	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Piping / Fittings	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 310, 320
Piping / Fittings	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Piping / Fittings	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Piping / Fittings	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Pump Casings	Pressure Boundary	Cast Iron	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A
Pump Casings	Pressure Boundary	Cast Iron	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 310, 320

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Pump Casings	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Selective Leaching	Selective Leaching of Materials Program	VII.C1-11	3.3.1-85	B, 320
Sight Glasses	Pressure Boundary	Glass	Primary Containment Air (Ext)	None	None	VII.J-8	3.3.1-93	A
Sight Glasses	Pressure Boundary	Glass	Raw Water (Int)	None	None	VII.J-11	3.3.1-93	A
Tanks	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A
Tanks	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Tanks	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program			H, 320
Tanks	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program			H, 310, 320
Tanks	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program			H, 320

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Tanks	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program			H, 320
Tanks	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program			H, 320
Thermowells	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A
Thermowells	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Thermowells	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Thermowells	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 310, 320
Thermowells	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Thermowells	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Thermowells	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Traps	Pressure Boundary	Cast Iron	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Traps	Pressure Boundary	Cast Iron	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 310, 320
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Traps	Pressure Boundary	Cast Iron	Raw Water (Int)	Loss of Material - Selective Leaching	Selective Leaching of Materials Program	VII.C1-11	3.3.1-85	B, 320
Valve Bodies	Pressure Boundary	Brass	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-12	3.3.1-88	A
Valve Bodies	Pressure Boundary	Brass	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-9	3.3.1-81	E, 320
Valve Bodies	Pressure Boundary	Brass	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-9	3.3.1-81	E, 320

Enclosure 2
NSPM Response to RAI 2.1-2
Additions to LRA Table 3.3.2-11, Auxiliary Systems - Heating System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG - 1801 Volume 2 Line Item	Table 1 Item	Notes
Valve Bodies	Pressure Boundary	Brass	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-9	3.3.1-81	E, 320
Valve Bodies	Pressure Boundary	Brass	Raw Water (Int)	Loss of Material - Selective Leaching	Selective Leaching of Materials Program	VII.C1-10	3.3.1-84	B, 320
Valve Bodies	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - Boric Acid Wastage	Boric Acid Corrosion Program	VII.I-10	3.3.1-89	A
Valve Bodies	Pressure Boundary	Carbon Steel	Primary Containment Air (Ext)	Loss of Material - General Corrosion	External Surfaces Monitoring Program	VII.I-8	3.3.1-58	A
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Galvanic Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 310, 320
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - General Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Pitting Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	VII.C1-19	3.3.1-76	E, 320

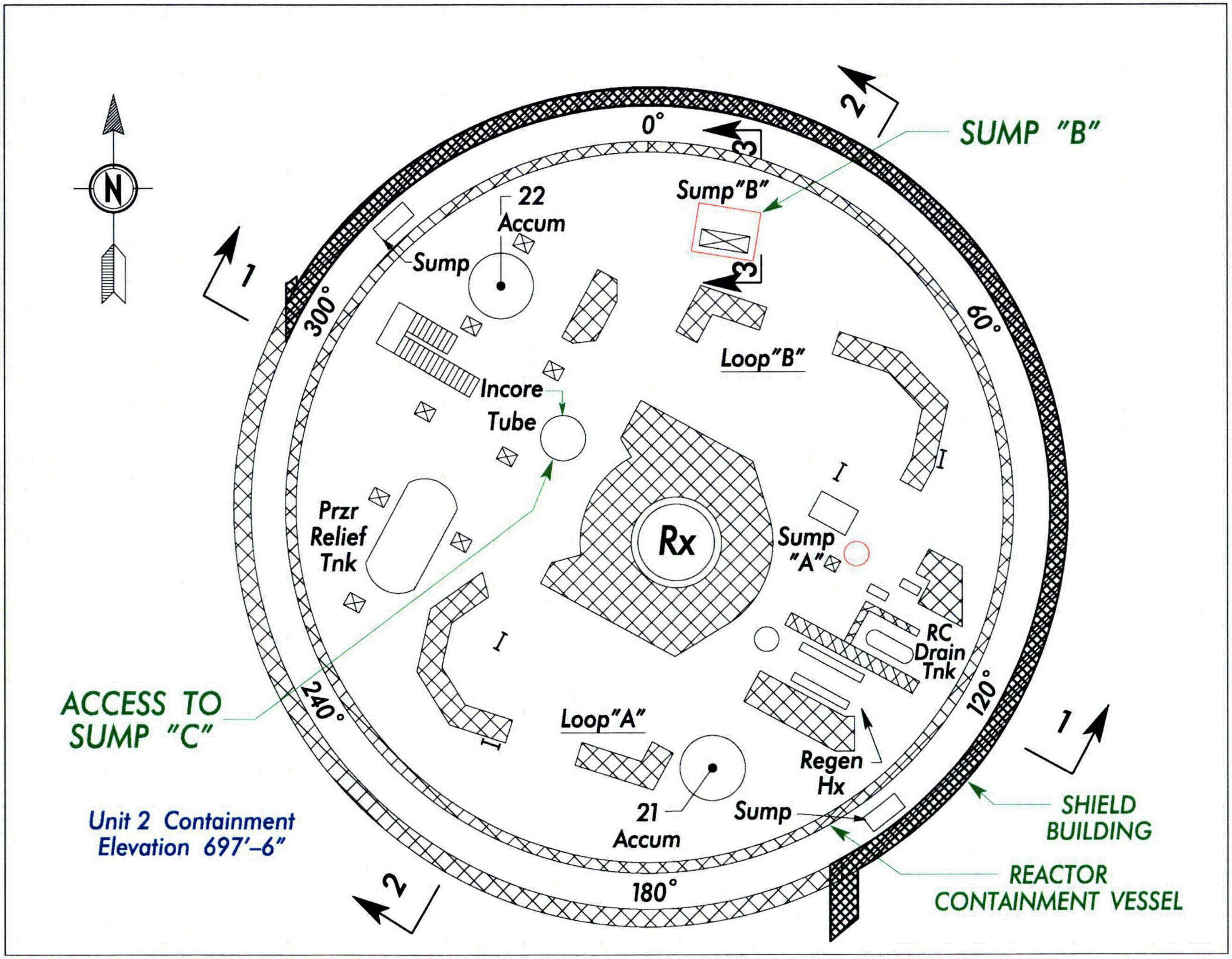
Enclosure 3

Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2

6 Pages

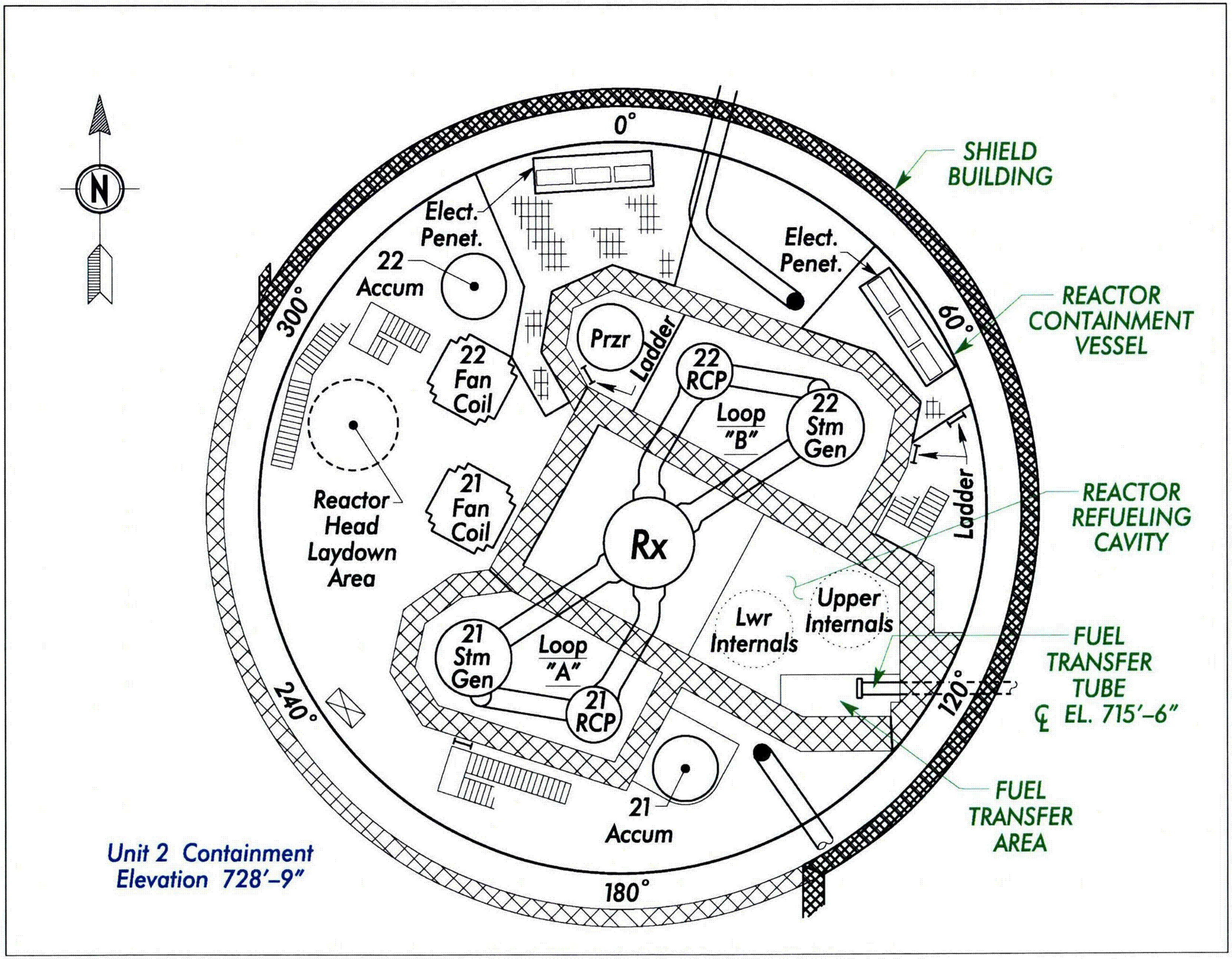
Enclosure 3

Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2



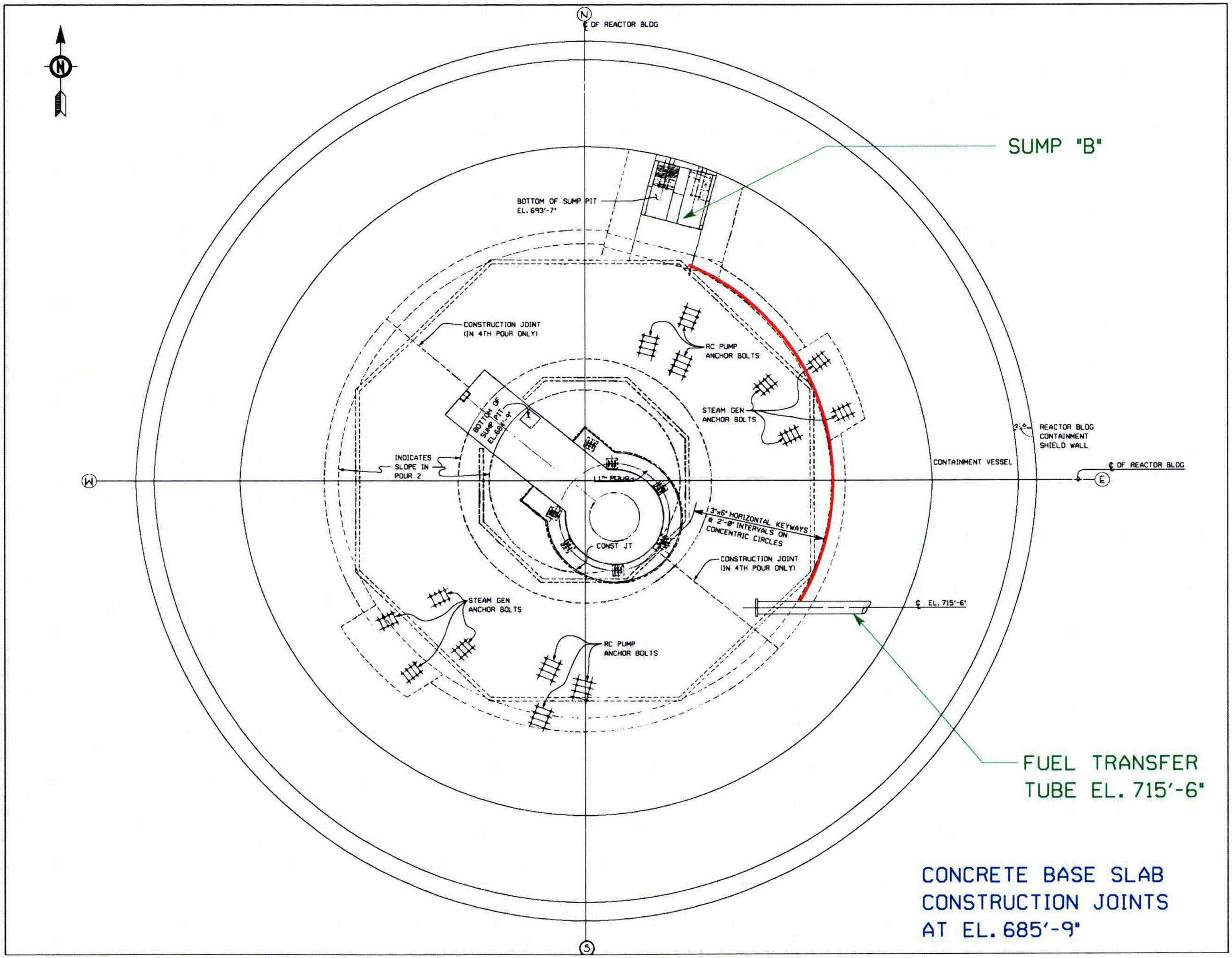
Enclosure 3

Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2



Enclosure 3

Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2



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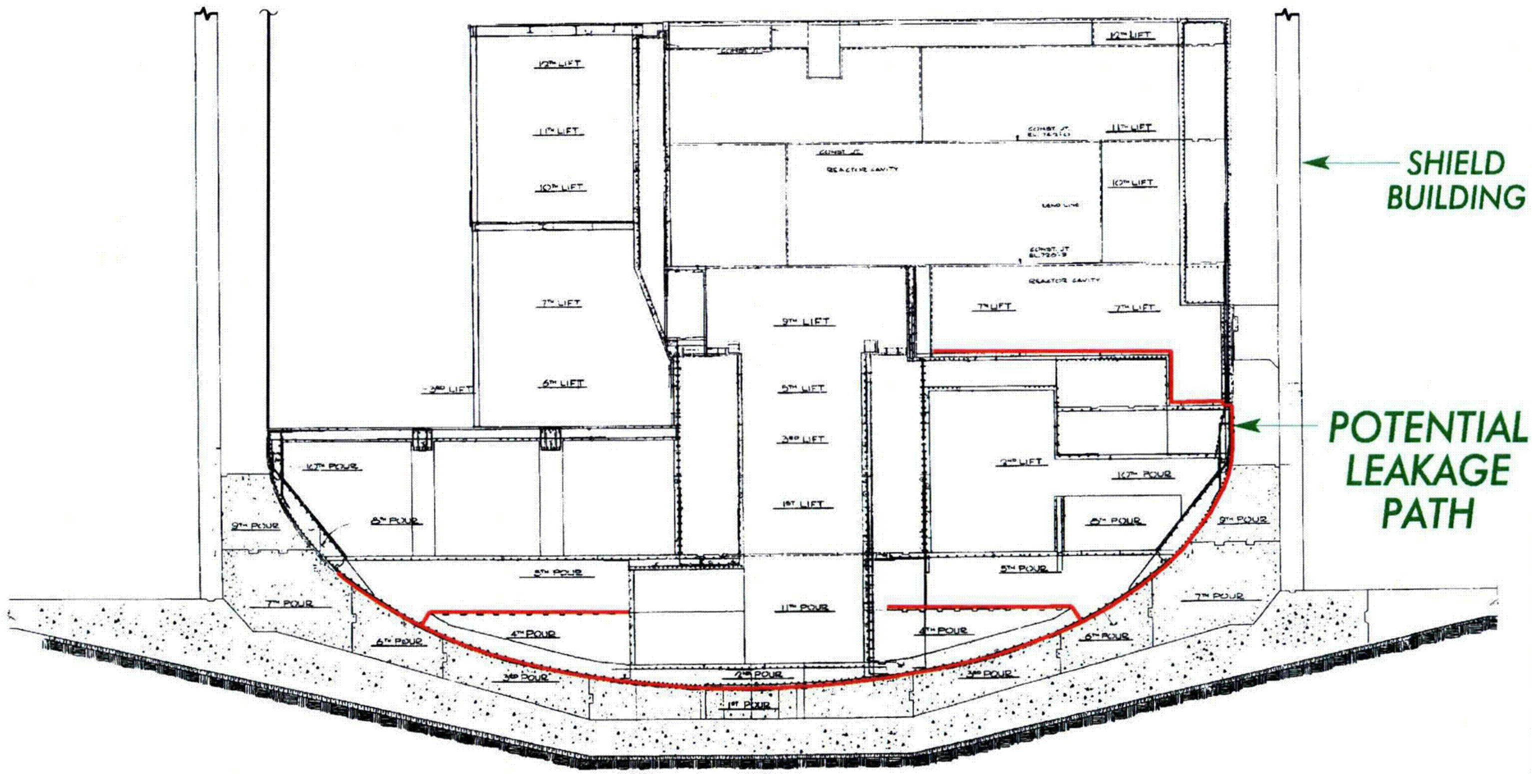
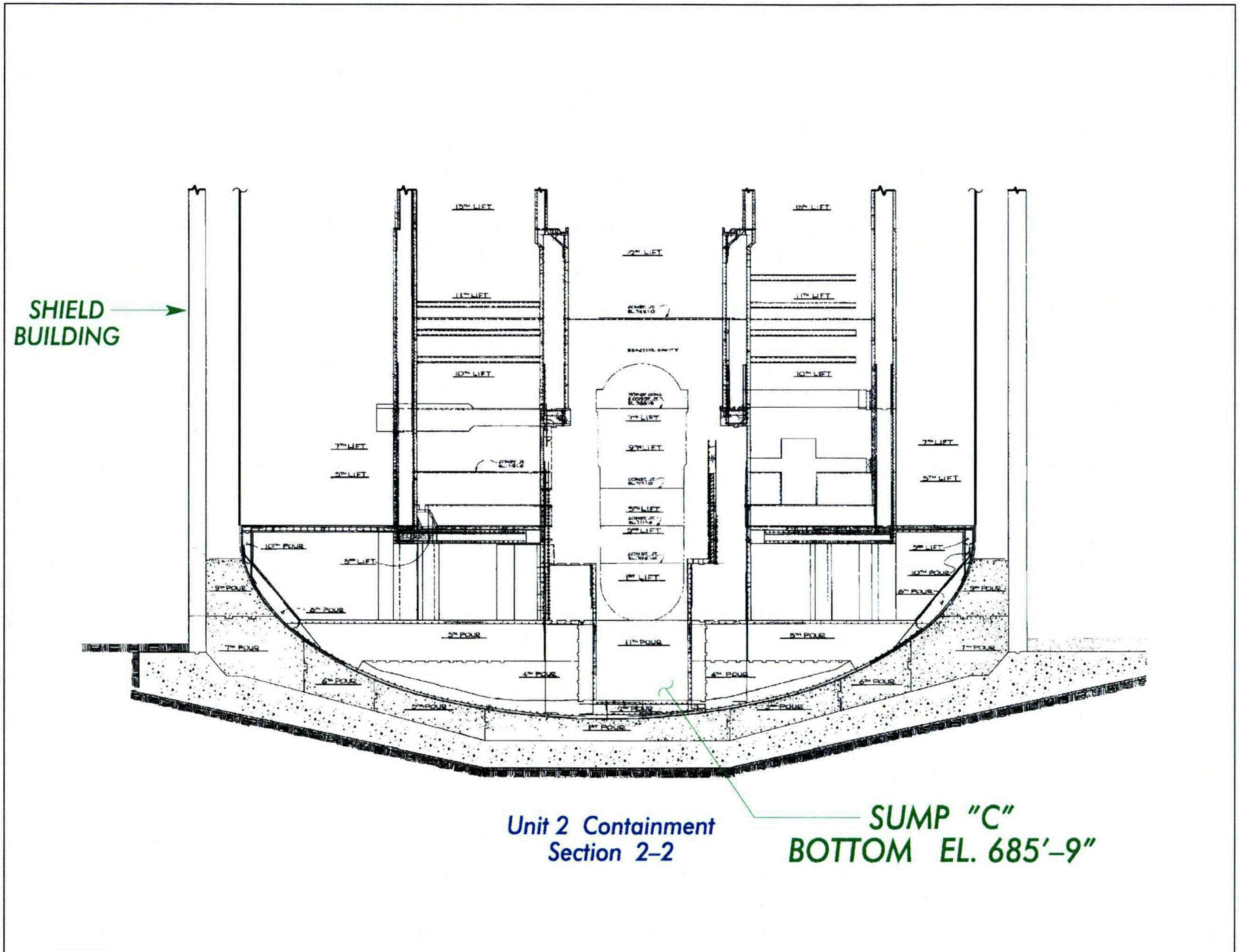
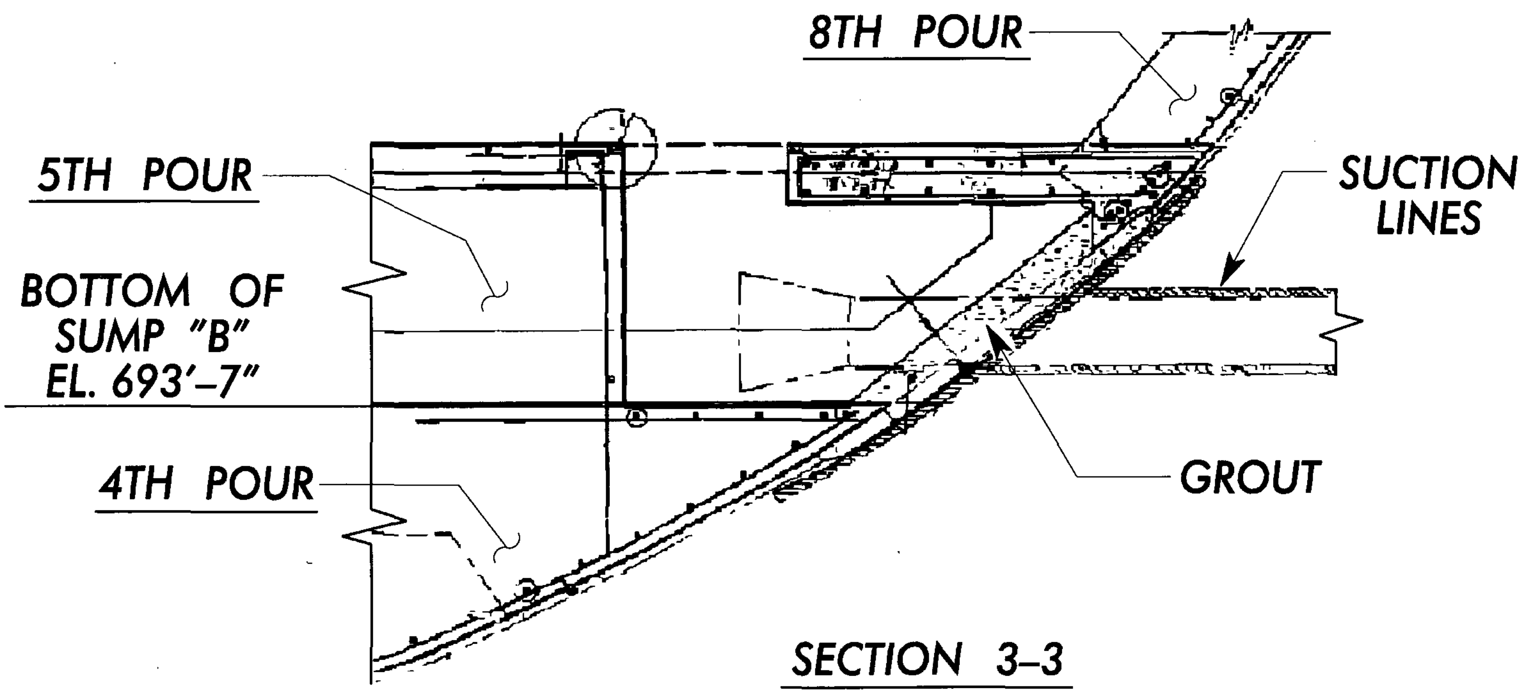
Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2



Unit 2 Containment
Section 1–1

Enclosure 3
Containment Sump Location and Concrete Pour Configuration Sketches for NSPM Response to RAI AMP-B2.1.38-2




8TH POUR
5TH POUR
SUCTION LINES
BOTTOM OF SUMP "B" EL. 693'-7"
4TH POUR
GROUT
SECTION 3-3