CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

REQUEST FOR ADDITIONAL INFORMATION (RAI) Set #7 RESPONSES

RAI 3.1.1.027-1

Background:

License renewal application (LRA) item 3.1.1.027 and Section 3.1.2.2.13 address Union Electric Company d/b/a Ameren Missouri's (the applicant's) aging management review (AMR) results for cracking due to stress corrosion cracking (SCC) and fatigue of the guide tube support pins of the control rod guide tube (CRGT) assemblies. LRA Section 3.1.2.2.13 states that this item is not applicable because this item is only applicable to nickel-alloy guide tube support pins. LRA Section 3.1.2.2.13 also states that Callaway guide tube support pins are made of stainless steel.

LRA Section B2.1.6, "[Pressurized Water Reactors] PWR Vessel Internals," indicates that based on industry operating experience, the applicant replaced the Alloy X-750 guide tube support pins (split pins) with strained hardened (cold worked) 316 stainless steel pins during refueling outage (RFO) 13 (spring 2004) to reduce the susceptibility for SCC in the split pins. The LRA also states that there were no cracked Alloy X-750 pins discovered during the replacement process.

In addition, LRA Table 3.1.2-1 indicates that cracking of the stainless steel CRGT support pins is managed by the Water Chemistry program and PWR Vessel Internals program (Existing Program Components) under LRA item 3.1.1.053. Furthermore, LRA Table 3.1.2-1 indicates that cracking of the stainless steel CRGT support pins is also managed by the American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program under LRA item 3.1.1.032.

In comparison, NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR) Section 3.1.2.2.13 states that cracking due to SCC and fatigue could occur in nickel alloy CRGT assemblies, guide tube support pins exposed to reactor coolant, and neutron flux. SRP-LR Section 3.1.2.2.13 also indicates that NUREG-1801, "Generic Aging Lessons Learned Report," (GALL Report) item IV.B2.RP-355 recommends further evaluation of a plant-specific program to ensure this aging effect is adequately managed.

After the issuance of SRP-LR, Revision 2, and GALL Report, Revision 2, the U.S. Nuclear Regulatory Commission (NRC or the staff) issued Revision 1 of the safety evaluation of Electric Power Research Institute (EPRI) MRP-227, Revision 0, "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," (as described in ADAMS Accession No. ML11308A770) on December 16, 2011. Section 3.2.5.3, "Evaluation of the Adequacy of Plant-Specific Existing Programs," of Revision 1 of the safety evaluation states:

> Westinghouse guide tube support pins are made from either 316 stainless steel or Alloy X750. There have been issues with cracking of the original Alloy X750 pins and many licensees have replaced them with type 316 stainless steel materials. Applicants/licensees shall evaluate the adequacy of their plant-specific existing program and ensure that the aging degradation is adequately managed during the extended period of operation for both Alloy X750 and type 316 stainless steel guide tube support pins (split pins). Therefore, it is recommended that the evaluation consider the need to replace the Alloy X750 support pins (split pins), if applicable, or inspect the replacement type 316 stainless steel support pins (split pins) to ensure that cracking has been mitigated and that aging degradation is adequately monitored during the extended period of operation.

Revision 1 of the safety evaluation of MRP-227 also states that this issue is Applicant/Licensee Action Item (A/LAI) 3.

Issue:

The LRA does not clearly address how the applicant evaluated the need for inspecting these replacement stainless steel support pins to ensure that aging degradation is adequately monitored during the period of extended operation, consistent with A/LAI 3.

Request:

a) Clarify whether the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program in conjunction with the PWR Vessel Internals program is the existing program that is used to manage cracking of these stainless steel CRGT support pins.

b) Describe how A/LAI 3 of Revision 1 of the staff's safety evaluation regarding MRP-227 was completed.

   As part of the response, provide the technical basis for why the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is adequate to ensure that aging degradation is adequately monitored during the period of extended operation. Clarify whether the VT-3 examination under Examination Category B-N-3 includes examination of the support pins to manage cracking.

   In addition, confirm whether the applicant's actions in response to A/LAI 3 are consistent with the existing NRC-mandated and vendor/supplier-recommended inspection monitoring bases for the applicant's stainless steel CRGT support pins. Otherwise, provide justification for the inconsistency of the applicant's actions with the inspection monitoring bases.

Callaway Response

a) LRA Section 3.1.2.2.13 (Cracking) states that item 3.1.1.027 is not applicable because this item is only applicable to nickel-alloy guide tube support pins. Callaway guide tube support pins are made of stainless steel. Section 3.1.2.2.14 (Wear) also is not applicable for stainless steel components. The associated GALL lines B2.RP-355 (Cracking) and B2.RP-356 (Wear) are for nickel-alloy only. LRA Table 3.1.2-1 identifies cracking of stainless steel control rod guide tube (CRGT) support pins is managed by the Water Chemistry program (B2.1.2) and the PWR Vessel Internals program (B2.1.6) consistent with GALL line B2.RP-346. LRA Table 3.1.2-1 also identifies cracking and wear of stainless steel CRGT support pins is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) consistent with GALL line B2.RP-382.

   Following the issue of ISG-2011-04, LRA Table 3.1.2-1 will be revised to evaluate cracking and wear of stainless steel CRGT support pins consistent with GALL line B2.RP-355 (Cracking) and B2.RP-356 (Wear). LRA item 3.1.1.027 will be revised consistent with ISG-2011-04 proposed changes.

b) Callaway has replaced the Alloy X750 CRGT support pins (split pins) with 316 stainless steel materials. The Alloy X750 support pins are included in the Existing Program Components of MRP-227-A, Table 3-3. The stainless steel CRGT support pins were added by the December 2011 NRC Safety Evaluation, Section 3.2.5.3. There are no NRC-mandated or vendor/supplier-recommended inspection requirements for the CRGT support pins in the Callaway CLB. Consistent with MRP-227-A, Category B-N-3 examinations of the

ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (ISI) program manage the aging degradation of Existing Program Components. Consistent with IWB-3520, category B-N-3 use a VT-3 examination. Also, IWB-3200(b) permits supplemental surface or volumetric examinations to determine the extent of relevant conditions detected by Category B-N-3 examinations. Therefore, the aging degradation of the CRGT support pins is adequately managed by Category B-N-3 examinations of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) in conjunction with the PWR Vessel Internals program (B2.1.6) during the period of extended operation.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 3.1.1.050-1

Background:

LRA Section B2, “Aging Management Programs,” states that GALL Report AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS),” is not credited.

LRA Table 3.1-1, item 3.1.1.050 states that portions of the Callaway reactor coolant loops are constructed of CASS and that the straight piping pieces are centrifugally cast and the fittings are statically cast. LRA item 3.1.1.050 also states that since the molybdenum and ferrite values for these fittings and piping pieces are below the industry accepted thermal aging significance threshold, thermal aging of the CASS reactor coolant piping is not a concern.

Callaway Final Safety Analysis Report (FSAR) Table 5.2-2 indicates that the reactor coolant pipe is made of centrifugal-cast SA-351, Grade CF8A and the reactor coolant fittings and branch nozzles are made of SA-351, Grade CF8A (cast stainless steel) and SA-182, (Code Case 1423-2) Grade 316N (non-cast stainless steel). The material information regarding CASS reactor coolant system components in the LRA and FSAR is summarized as follows.

- Reactor coolant pipe: centrifugal-cast low-molybdenum CASS (SA-351 , Grade CF8A)
- Reactor coolant fittings: static-cast low-molybdenum CASS (SA-351, Grade CF8A)
- Reactor coolant branch nozzles: low-molybdenum CASS (SA-351, Grade CF8A)

In comparison, GALL Report AMP XI.M12 states that for low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A or other steels with molybdenum not exceeding 0.5 weight percent), only static-cast steels with ferrite greater than 20 percent are potentially susceptible to thermal aging embrittlement. GALL Report AMP XI.M12 also indicates that in the susceptibility screening method, ferrite content is calculated by using the Hull’s equivalent factor (described in NUREG/CR-4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” Revision 1) or a staff-approved method for calculating delta ferrite in CASS materials.

Issue:

The staff needs additional information to confirm that the applicant’s methodology for screening of CASS for susceptibility to thermal aging embrittlement is consistent with the GALL Report. The LRA does not clearly indicate whether the reactor coolant branch nozzles are made of static-cast material or centrifugal-cast material. In addition, the LRA does not provide the ferrite contents of the CASS materials discussed above. Furthermore, the LRA does not clearly indicate that the applicant’s screening method is consistent with NUREG/CR-4513, Revision 1, as referenced in GALL Report AMP XI.M12.

Request:

a) Clarify whether the reactor coolant branch nozzles are made of static-cast CF8A material or centrifugal-cast CF8A material.

b) Provide the bounding-case chemical composition of the reactor coolant fittings and branch nozzles that estimates the highest ferrite content of these CASS components.

c) Provide the calculated ferrite content in order to confirm that the bounding case analysis indicates no susceptibility of these CASS components to thermal aging embrittlement.

As part of the response, clarify whether the applicant's screening method is consistent with the guidance of NUREG/CR-4513, Revision 1, for ferrite content calculations using the Hull's equivalent factor as referenced in the GALL Report.

Callaway Response

a) The CASS reactor coolant branch nozzles are made of static-cast CF8A material.

b) The bounding-case chemical composition that estimates the highest ferrite content of the reactor coolant fittings and branch nozzles that are made of static-cast CF8A material are provided below and are associated with Heat Numbers 3-3325 and 3-3447. Materials with these heat numbers are found in:

   1) 31"x29" 50° elbow of Loop 1 hot leg,
   2) 10" 45° nozzle on Loop 3 cold leg, and
   3) 31" 90° elbow of Loop 3 crossover at steam generator side.

	Cr (%)	Mo	Si	Ni	Mn	N	C
31"x29" 50° elbow (Loop 1)	20.82	0.31	1.7	8.3	0.65	0.04	0.06
10" 45° nozzle (Loop 3)	20.5	0.26	1.8	8.4	0.67	0.04	0.05
31" 90° elbow (Loop 3)	(same as 10" 45° nozzle of Heat #3-3447)						

c) The calculated ferrite contents, using Hull's Factors described in NUREG/CR-4513, are 19.65% and 18.69% for Heat # 3-3325 and 3-3447, respectively. They are below the threshold value of 20% for static-cast CF8A material. The guidance of NUREG/CR-4513, Rev. 1, Section 3.2 for ferrite content calculations using Hull's equivalent factors is shown below:

$Cr_{eq} = Cr\% + 1.21(Mo\%) + 0.48(Si\%) – 4.99$

$Ni_{eq} = Ni\% + 0.11(Mn\%) – 0.0086\ (Mn\%)^2 + 18.4(N\%) + 24.5(C\%) + 2.77$

The concentration of N, when not provided on the CMTR, is assumed to be 0.04%.
(Ref: NUREG/CR-4513, Rev. 1, Section 3.2)

The ferrite content $\delta_c\%$ is given by:

$\delta_c\% = 100.3\ (Cr_{eq}/Ni_{eq})^2 – 170.72(Cr_{eq}/Ni_{eq}) + 74.22.$

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 3.1.1.063-1

Background:

SRP Table 3.1-1, item 3.1.1.063 addresses steel or stainless steel closure bolting exposed to air with reactor coolant leakage. The GALL Report recommends GALL Report AMP XI.M18, “Bolting Integrity,” to manage loss of material due to general (steel only), pitting, and crevice corrosion or wear for this component group. The LRA states that this item is not applicable because the item applies only to boiling water reactor (BWR) plants.

Issue:

The staff lacks sufficient information to evaluate the applicant’s claim because although the SRP-LR states that item 3.1.1.063 is applicable to BWRs, the applicant has in-scope steel or stainless steel closure bolting exposed to borated water leakage in LRA Tables 3.1.2-2, 3.2.2-1, 3.2.2-5, 3.3.2-2, 3.3.2-10, 3.3.2-24, and 3.3.2-28. The staff noted that the applicant is managing these items for loss of preload and cracking, but not for loss of material. The staff also noted that the applicant has in-scope steel and stainless steel closure bolting exposed to plant indoor air and atmosphere/weather environments which are being managed for loss of material.

Request:

State the basis for why loss of material is not applicable to in-scope steel or stainless steel closure bolting exposed to air with reactor coolant leakage, or provide an AMP to manage this aging effect.

Callaway Response

SRP Table 3.1-1, item 3.1.1.063, is applicable to NUREG-1801 line IV.C1.RP-42 for closure bolting in a BWR Reactor Coolant Pressure Boundary component. SRP Table 3.1-1, item 3.1.1.063 is not applicable to pressurized water reactor (PWR) plants because the chemistry of the reactor coolant system in a boiling water reactor (BWR) is different from the chemistry of the reactor coolant system in a PWR.

The only aging effects identified in the GALL report for stainless steel closure bolting exposed to air with borated water leakage or air with (PWR) reactor coolant leakage are cracking due to stress corrosion cracking and loss of preload. However, the GALL report identifies the aging effect of loss of material due to pitting and crevice corrosion for stainless steel closure bolting in an environment of plant indoor air. Generic components for stainless steel closure bolting with an environment of plant indoor air and an aging effect of loss of material have been added to systems which previously included stainless steel closure bolting in an environment of borated water leakage, but not plant indoor air. These systems include the reactor coolant system, containment spray system, high pressure coolant injection system, fuel pool cooling and cleanup system, chemical and volume control system, and the boron recycle system (LRA Table 3.3.2-28 for miscellaneous systems in scope only for criterion 10 CFR 54.4(a)(2)). The residual heat removal system and the liquid radwaste system were not revised because they already included loss of material for stainless steel closure bolting in an environment of plant indoor air.

LRA Tables 3.1.2-2, 3.2.2-1, 3.2.2-5, 3.3.2-2, 3.3.2-10, and 3.3.2-28 have been revised, as shown on LRA Amendment 9 in Enclosure 2, to add loss of material due to pitting and crevice corrosion for stainless steel bolting in a plant indoor air environment that is managed by the Bolting Integrity program (B2.1.8).

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 9, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

RAI 3.2.1.063-1

Background:

LRA Table 3.2.1, item 3.2.1.063 and LRA Table 3.3.1, item 3.3.1.120 address stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled, air with borated water leakage, concrete, air-dry, or gas, and state that there are no aging effects requiring management and no AMP is proposed. The GALL Report states that there are no aging effects requiring management and no AMP is proposed for these component groups. However, the GALL Report recommends that stainless steel components exposed to treated borated water or condensation be managed for loss of material

LRA Tables 3.2.2-6 and 3.3.2-2 state that stainless steel expansion joints, piping, and tanks exposed internally to borated water leakage have no aging effects requiring management and no AMP is proposed.

Issue:

The GALL Report environment of air with borated water leakage is usually referred to as an external environment. It is unclear to the staff how the components exposed internally to borated water leakage are configured such that exposure to borated water leakage can occur, but the leakage does not accumulate such that the environment becomes borated water or condensation.

Request:

Explain the configuration of the components exposed internally to borated water leakage and how accumulation of the borated water leakage is prevented. If accumulation of borated water leakage can occur, explain why the components have no aging effects requiring management.

Callaway Response

The components identified in LRA Table 3.2.2-6 with an internal environment of borated water leakage are associated with the residual heat removal (RHR) lines from each of the containment recirculation sumps to the suction of the RHR pumps. The isolation valve in these lines closest to the recirculation sumps is located within a watertight enclosure outside the containment building. This configuration is shown in FSAR Figure 6.2.4-1, page 14. The enclosure is identified as a tank in the LRA, and includes expansion joints and guard pipes. Since part of the RHR lines is filled with borated water, an environment of borated water leakage was selected as the internal environment of the enclosures, expansion joints, and guard pipes. The domes of the enclosures are periodically removed for testing of the isolation valves and visual inspection of the enclosures. If evidence of borated water leakage is observed, corrective action is taken in accordance with the corrective action program and the boric acid corrosion program. This prevents any significant accumulation of borated water within the enclosures.

The component in LRA Table 3.3.2-2 with an internal environment of borated water leakage is the expansion joint associated with the fuel transfer tube which runs from the containment building to the fuel building. The penetration for the fuel transfer tube consists of a 20-inch diameter stainless steel pipe installed inside a 26-inch sleeve. The sleeve includes an expansion joint in the fuel building to allow for differential movement between the structures. This configuration is shown in FSAR Figure 3.8-48. The external surface of the expansion joint is exposed to borated water during refueling operations, but the area between the fuel transfer tube and the sleeve (including the expansion joint) is dry. Borated water leakage into this area cannot occur because the sleeve is welded to the fuel transfer tube, so that the internal environment of the expansion joint should be plant indoor air (internal).

LRA Table 3.3.2-2 has been revised, as shown on Amendment 9 in Enclosure 2, to indicate that the internal environment for the expansion joint and the interior fuel transfer tube surfaces between the 20-inch diameter stainless steel pipe and the 26-inch sleeve is plant indoor air. Table 3.0-1 has also been revised, as shown on Amendment 9 in Enclosure to include an entry for plant indoor air as an internal environment.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 9, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

RAI 3.5.1.016-1

Background:

SRP-LR Table 3.5-1, item 16, recommends using the XI.S2, “ASME Section XI, Subsection IWL,” or XI.S6, “Structures Monitoring” programs to manage increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack for all types of BWR/PWR concrete components of “concrete (accessible areas): basemat, concrete: containment; wall; basemat.”

Issue:

LRA Table 3.5-1, item 3.5.1.016, is listed as “not applicable” with a discussion stating that “Callaway is a PWR plant with a concrete containment. This NUREG-1801 line is applicable only for steel containments or BWRs.”

It is not clear how the applicant concluded in the LRA that item 3.5.1.016 is applicable for steel containments or BRWs only. GALL item II.A2.CP-72 recommends using the XI.S2, “ASME Section XI, Subsection IWL,” or XI.S6, “Structures Monitoring” programs to manage increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack in concrete structures for PWRs, with no statement disclosing PWR containments.

Request:

Provide the technical justification as to why item 3.5.1.016 was considered as “not applicable” in the LRA, and the concrete components of “concrete (accessible areas): basemat, concrete: containment; wall; basemat” does not require aging management at Callaway.

Callaway Response

NUREG-1800, Table 3.5-1 links Item 16 to GALL line II.A2.CP-72. GALL Chapter II, Section A2, manages the aging of PWR steel containment structures, which are ASME Class MC (Metal Containment). The Callaway containment structure is ASME Class CC (Concrete Containment), which is managed under GALL Chapter II, Section A1. The same aging effects that are managed by Line II.A2.CP-72 are managed by Line II.A1.CP-100 for Class CC components, as noted in LRA Table 3.5.2-1. Therefore, Line II.A2.CP-72 is not applicable to Callaway.

NUREG-1800, Table 3.5-1 also links Item 16 to GALL lines II.B1.2.CP-106, II.B2.2.CP-106, and II.B3.1.CP-72. These lines do not apply to Callaway because GALL Chapters II.B1, II.B2, and II.B3 apply only to BWR containments. Therefore, Item 16 from Table 3.5-1 is not applicable to Callaway, and aging of concrete elements at Callaway is managed by other sections of the GALL

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 3.5.1.095-1

Background:

GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF" covers the inspection criteria for ASME Class 1, 2, and 3 component supports for license renewal and recommends visual inspection of a sample of supports.

In LRA Table 3.5.2-12 there are stainless steel ASME Class 1, 2, and 3 supports and mechanical equipment supports exposed to air-indoor uncontrolled or borated water leakage which cites item 3.5.1.095 and state that there are no aging effects requiring management and no AMP is proposed.

Issue:

It is unclear to the staff why no AMP is proposed to manage the ASME Class 1, 2, and 3 supports and mechanical equipment supports, given that they appear to be within the scope of the ASME Section XI, Subsection IWF program.

Request:

Provide justification for why the supports are not being managed using the ASME Section XI, Subsection IWF program; or provide an appropriate program to manage the aging effects.

Callaway Response

LRA Table 3.5.2-12 identifies all material/environment combinations associated with each component type and ensures that all aging effects that could be experienced by those material/environment combinations have been addressed by the appropriate aging management programs. If a component is constructed of more than one material (e.g., a carbon steel support with a stainless steel U-bolt), separate lines in Table 3.5.2-12 are necessary to address the multiple material/environment combinations. Therefore, a single support may correspond with multiple lines in Table 3.5.2-12.

The scope of the IWF aging management program, and the samples selected for inspection, are based on individual component supports. While part of a component support may be constructed of a material that does not require aging management, the support is still within the scope of IWF and is inspected appropriately. All ASME Class 1, 2, or 3 supports are within the scope of license renewal and are being managed by the ASME Code Section XI, Subsection IWF program.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 4.7.3-1

Background:

LRA Section 4.7.3 states that the evaluation considered a plant life of 40 years, which includes 20 years under the current license plus 20 years for plant life extension. The amount of corrosion was calculated assuming a corrosion rate of 0.001 in/yr for normal operating conditions; an outage corrosion rate of 0.015 in/yr with the average outage duration of less than 8 weeks every 18 months; and a 2-week startup period after each outage with a corrosion rate of 0.010 in/yr. In addition, the LRA also discusses assuming an outage corrosion rate for the entire 40 years, which would yield 0.6 in. of corrosion.

LRA Section 4.7.3 indicates that reactor pressure vessel (RPV) low-alloy steel has been left exposed to the reactor coolant and that the vessel minimum wall thickness evaluation demonstrated that the wall thickness, 5.38 in, minus the maximum degraded area depth, 0.28 in., meets the criterion of NB-3324.2, 4.329 in.

Issue:

LRA Section 4.7.3 did not specify the thickness of the cladding and whether the wall thickness of 5.38 in. includes this cladding thickness. The staff noted that corrosion rates are dependent on the temperature, oxygen content and concentration of the boric acid of the environment and the applicant has not provided the technical bases regarding the use of the specified corrosion rates basis for its plant-specific conditions.

Since only the maximum degraded area depth of 0.28 in. was discussed in LRA Section 4.7.3 with respect to the criterion of NB-3324.2; the staff could not determine whether the degraded depth was a calculated/measured value at the time the cladding was discovered missing or if it was the maximum degraded area depth at the end of the period of extended operation. It is also not clear whether the applicant's corrosion analysis considered degradation associated with a corrosion rate when meeting the criterion of NB-3324.2. The staff requires this information to verify the adequacy of the disposition of the time-limited aging analysis (TLAA) in accordance with 10 CFR 54.21(c)(1)(i).

Request:

a) Identify the thickness of the cladding and clarify whether the wall thickness of 5.38 in. includes this cladding thickness.

b) Justify any assumptions, on the parameters including but not limited to temperature, oxygen content and concentration of the boric acid, which were used in selecting the corrosion rates discussed in LRA Section 4.7.3. Justify that the corrosion rate of 0.015 in/yr is bounding for the conditions at the plant.

c) Confirm that the maximum degraded area depth of 0.28 in. was a calculated/measured value at the time the cladding was discovered to be missing.

    - If it was not, justify that the corrosion analysis only needed to consider 40 years of operation (i.e., 2004-2044), rather than 60 years of operation (1984-2044). In addition, explain how the maximum degraded area depth of 0.28 in. was determined.
    - If it was, clarify whether the corrosion analysis considered degradation due to a corrosion rate through the period of extended operation. Specifically, explain why LRA Section 4.7.3 appears to indicate that only the "maximum degraded area depth" was used to determine if the wall thickness met the criterion of NB-3324.2.

d) Provide revised LRA Sections 4.7.3 and A3.6.3, as necessary.

Callaway Response

a. The minimum design wall thickness of the low-alloy steel reactor vessel bottom head is 5.38 inches. This does not include the cladding. However the analysis conservatively assumes that the nominal cladding thickness of 0.22 inches is included in the 5.38 inches.

b. The analysis of corrosion to the reactor pressure vessel base metal caused by damaged cladding follows the example of and uses the corrosion rates from EPRI TR-1000975 "Boric Acid Corrosion Guidebook," Appendix B. The calculation assumes corrosion rates for three plant conditions (normal operation; refueling; and startup) based on test data.

   The normal operating corrosion rate of 0.001 in/yr represents a conservative value for carbon steel and low-alloy steel immersed in deaerated water at high temperatures. EPRI TR-1000975 identifies a corrosion rate of less than 0.001 in/yr based on a series of tests conducted to determine the corrosion rate of carbon steel and low-alloy steel in deaerated water with 2500 to 3000 ppm boron at temperatures up to 590°F (310°C). Callaway's normal operating conditions are consistent with these plant conditions. Hydrogen concentration is maintained at 25 to 50 cc/kg which ensures the RCS is free of oxygen (deaerated). Callaway's historical maximum hot full power boric acid concentration is 1400 ppm and the average RCS temperature is 585°F.

   The refueling corrosion rate of 0.015 in/yr represents low alloy steel immersed in aerated water at low temperatures. EPRI TR-1000975 identifies a corrosion rate of 0.015 in/yr based on a series of tests conducted to determine the corrosion rate of A-302 Grade B low-alloy steel in aerated water with 2500 ppm boron at low temperatures, up to 140°F (60°C). Callaway's refueling conditions are consistent with these plant conditions. Callaway's nominal refueling boric acid concentration and maximum refueling temperature are 2500 ppm and 140ºF.

   The startup corrosion rate of 0.010 in/yr is based on tests documented in EPRI TR-100975 designed specifically to simulate typical plant start-up conditions on unclad, low-alloy, pressure vessel steels. Plate specimens of SA-533 Grade B, SA-508 Class 2, and SA-508 manually welded to SA-533 Grade B were immersed in an autoclave with deionized water and 723 ppm boron, 1.8 ppm lithium, and 0.4 ppm ammonia. The autoclave was not deaerated prior to start of the testing, but no additional oxygen was added during the test. The specimens were held at 350°F (176°C). The results of this test showed that all materials experienced average corrosion rates of 0.016–0.017 in/yr (0.41–0.43 mm/yr). Callaway is required to establish oxygen controls in the RCS prior to exceeding 250°F; therefore deaerated conditions will be established prior to exceeding the temperature range of test data. While the test indicates a higher corrosion rate, this does not impact the conclusions because of the short duration of the condition relative to the other conditions.

c. The maximum degraded depth is based on ultrasonic testing (UT) results taken at the time the indications were identified.

   - N/A
   - The UT reports indicate a maximum defect depth of 0.14 inches from the inner surface, but the evaluation assumes that the low-allow base metal depth is reduced by an additional 0.14 inches. The 0.28 inch defect depth bounds the measured indications plus the calculated maximum 40 year corrosion loss of 0.119 inches,

which assumes an 8 week outage every 18 months. The LRA does note that even if the conservative outage corrosion rate of 0.015 inches/year is assumed for the entire 40 year period, the resulting wall loss would be only 0.6 inches. A 0.6 inch wall loss added to the larger assumed defect depth of 0.28 inches would still leave the reactor wall thickness at 4.5 inches (5.38 inches – 0.28 inches - 0.6 inches = 4.5 inches). This still satisfies the minimum wall thickness requirement based on the criterion of NB-3324.2 of 4.329 inches.

d. LRA Sections 4.7.3 and Appendix A3.6.3 have been revised as shown in Amendment 9 in Enclosure 2 to include the cladding thickness and the effect of corrosion on the minimum wall thickness evaluation.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 9, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

RAI 4.7.9-1

Background:

LRA Section 4.7.9 addresses the applicant's TLAA for replacement steam generator tube wear for the period of extended operation. LRA Section B2.1.9, "Steam Generators," indicates that the previous steam generators were replaced in fall 2005 (RFO 14). LRA Section 4.7.9 states that this analysis assumed a cumulative operating service of 45 years. LRA Section 4.7.9 also compared the calculated maximum wear of 0.010 in. to the maximum allowable wear of 40 percent of the tube wall thickness, 0.0156 in.

Issue:

Neither the FSAR nor LRA Section A3.6.9 (the FSAR supplement for the TLAA as amended by letter dated May 3, 2012) include the calculated maximum wear of the steam generator tubes (i.e., 0.010 in. for 45 years), which is the major result of the TLAA.

Request:

Justify why the FSAR or FSAR supplement (LRA Section A3.6.9) does not include the calculated maximum wear of steam generator tubes (i.e., 0.010 in. for 45 years). Alternatively, revise the FSAR supplement to include the calculated maximum wear.

Callaway Response

In response to RAI 4.7.9-2, LRA Amendment 9 changes the disposition of the tube wear analysis from a validation, 10 CFR 54.21(c)(1)(i), to management, 10 CFR 54.21(c)(1)(iii), and credits the steam generator aging management program (XI.M19). The steam generator aging management program, as described in LRA Appendix B2.1.9, ensures the integrity of the tubes by maintaining the loss of tube wall thickness less than 40%. Since the credited aging management incorporates the Technical Specification 5.5.9.c requirement for steam generator tube wall thickness, the analyzed wear rate does not need to be included in the FSAR Supplement.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 4.7.9-2

Background:

LRA Section 4.7.9 addresses the applicant's TLAA for replacement steam generator tube wear for the period of extended operation. LRA Section B2.1.9, "Steam Generators," indicates that the previous steam generators were replaced in fall 2005 (RFO 14). LRA Section 4.7.9 states that this analysis assumed a cumulative operating service of 45 years. LRA Section 4.7.9 also compared the calculated maximum wear of 0.010 in. to the maximum allowable wear of 40 percent of the tube wall thickness, 0.0156 in.

In comparison, the applicant's letter dated May 17, 2012, encloses "Callaway Energy Center Steam Generator Tube Inspection Report." Section 4.0 of the inspection report addresses the results of the applicant's in-service inspection of the steam generators, which was conducted during RFO 18 (corresponding to 4.1 effective full power years).

The following summarizes the inspection results and related information for the tube wear observed in the four replacement steam generators as addressed in Table 2 of the steam generator inspection report dated May 17, 2012:

- Callaway's plugging limit for the steam generator tubes was set at 28 percent through-wall, conservatively, for the next three cycles (Cycles 19, 20, and 21).
- All of the in-service tubes were inspected (total 22, 143 tubes, except for one tube plugged during manufacturing).
- A total of 258 steam generator tubes indicated anti-vibration bar wear or tube support plate wear.
- Based on the inspection, a total of 29 tubes were plugged (among them, 29 tubes were due to anti-vibration bar wear and one tube was plugged due to tube support plate wear).

Issue:

Some of the actual tube wear rates exceeded the calculated maximum wear rate. Therefore, the staff needs additional information that can justify the validity of the applicant's TLAA.

Request:

a) Provide justification for why the applicant's TLAA is valid even though some of the steam generator tubes indicated wear rates greater than the calculated maximum wear rate (0.010 in. for 45 years).

   As part of the response, provide the number of steam generator tubes that indicated wear rates greater than the calculated maximum wear rate.

b) If necessary, identify any impact of the operating experience on the applicant's TLAA and revise the TLAA accordingly, for adequate aging management.

As part of the response, discuss how the applicant will manage steam generator tube wear in case the actual tube wear indications are greater than the calculated maximum tube wear.

Callaway Response

a. The steam generator tube wear analysis does not satisfy an ASME Code requirement, but satisfies the design specification requirement that excessive tube fretting and tube wear not occur if a tube support is non-effective in limiting the tube motion. Excessive is defined in the analysis as wear exceeding the Technical Specification 5.5.9.c tube plugging criterion of 40% through-wall (TW) in 45 years. This criterion is also incorporated in the steam generator aging management program (XI.M19), discussed in LRA Appendix B2.1.9.

   Table 1, Tubes with AVB Wear Indications, (refer to page 20 of this enclosure) provides a summary of wear and plugging for the steam generator tubes due to contact with the anti-vibration bars (AVB). AVB wear is the most active wear mechanism in the replacement steam generators as observed by the steam generator tube inspections. Only 1% (232/23488) of all the steam generator tubes shows indications of AVB wear. This demonstrates the vast majority of the tubes are showing excellent performance with regards to wear. Table 2, AVB Wear Indications, (refer to page 20 of this enclosure) provides a summary of the identified indications. All wear indications are justified for continued operation till the next scheduled inspection, typically 3 cycles, by establishing a wear rate based on measured data. The 1R18 inspections resulted in a tube plugging criterion of 28%. Even though only 8% of the indications exceed this limit, tube plugging results in 23% of the indications being removed from service because of multiple indications on a single tube. Since the wear analysis describes the wear experienced by the typical steam generator tube and all tubes showing signs of excessive wear are removed from service, the TLAA will remain valid for the period of extended operation.

   The steam generator tube wear analysis analyzes the non-linear vibration due to the gap between the tube and support. The wear rate is not constant over time. The gap between the tubes and supports will increase as a result of the wear which in turn reduces the wear rate. This is confirmed by the steam generator tube inspection report which compares the wear growth rates between 1R15 and 1R18 outages and notes an average reduction in wear rates of 50%. However the analysis assumes a constant gap size. The constant gap size conservatism provides justification for using the manufacturing nominal gap size when determining the amount of wear. If the gap size is reduced to the minimum (0 inches), the wear rate greatly increases, particularly early in life.

   In order to compare predicted-to-measured, it is necessary to estimate the amount of wear at 6 years, the duration the replacement steam generators have been in operation. As discussed above, the wear presented in the LRA of 0.010 inches is not linear with respect time. For the comparison, it is assumed that 50% of the predicted wear will be experienced in the first 6 years. This assumption is based on analyses which update the gap size each time step. The updated gap analyses show that a tube will experience from 25% to 50% of the total wear in the first 6 years. The assumption results in a predicted wear of less than 13% through-wall at 6 years.

   Table 3, Comparison of Predicted-to-Measured for AVB Wear Indications, (refer to page 20 of this enclosure) provides a comparison of the identified indications to the predicted wear. The inspections observed an average wear depth of 14.1% for the tubes with wear indications, which corresponds well with the predicted 13%. Of the 589 indications of wear, 284 or 48% of the indications are greater than predicted after 6 years. The 284 indications greater than predicted are justified for continued operation through the steam generator aging management program using measured wear rates.

b. Due to this tube wear operating experience the TLAA disposition has been changed to management in accordance with 10 CFR 54.21(c)(1)(iii). LRA Section 4.7.9 has been revised as shown in Amendment 9 to reflect a TLAA disposition consistent with 10 CFR 54.21(c)(1)(iii).

   The steam generator aging management program (XI.M19), discussed in LRA Appendix B2.1.9 manages cracking, loss of material, and wall thinning of the steam generators. The program detects flaws in tubing, plugs, and tube supports needed to maintain tube integrity. Assessment of tube integrity and plugging or repair criteria of flawed tubes is performed in accordance with plant technical specifications and the program implementing procedures. Plugs and tube supports with aging indications are evaluated for corrective actions in accordance with the Callaway Corrective Action Program and the Callaway Steam Generator program. Therefore, this TLAA will be managed for the period of extended operation.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 9, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

Table 1 – Tubes with AVB Wear Indications

Steam Generator	Total Number of Tubes	Number with Indications	Percentage with Indications	Number of Tubes Plugged	Percentage of Tube Plugged
SG A	5872	71	1.21%	11*	0.19%
SG B	5872	40	0.68%	6	0.10%
SG C	5872	100	1.70%	12	0.20%
SG D	5872	21	0.36%	1	0.02%
Total	23488	232	0.99%	30	0.13%

* 1 tube was plugged pre-service.

Table 2 - AVB Wear Indications

Steam Generator	Total Number of Indications	Number > 28% TW	Percentage > 28% TW	Number of Indications Plugged	Percentage of Indications Plugged
SG A	180	19	10.56%	47	26.11%
SG B	108	8	7.41%	29	26.85%
SG C	256	20	7.81%	53	20.70%
SG D	45	1	2.22%	4	8.89%
Total	589	48	8.15%	133	22.58%

Table 3 – Comparison of Predicted-to-Measured for AVB Wear Indications

Steam Generator	Number of Indications	Average Wear	Maximum Wear	Number > 13% TW*	Percentage > 13% TW*
SG A	180	14.2	35	88	48.89%
SG B	108	14.7	37	60	55.56%
SG C	256	14.1	39	120	46.88%
SG D	45	11.9	30	16	35.56%
Total	589	14.1	39	284	48.22%

* 13% through-wall (TW) is the estimate amount of wear after 6 years of wear.

RAI 4.7.9-3

Background:

Recent industry operating experience indicates that steam generator tube-to-tube wear could occur due to tube-to-tube interactions, as addressed in NRC's letter dated March 27, 2012, (ADAMS Accession No. ML12087A323).

LRA Section 4.7.9 addresses the applicant's TLAA for replacement steam generator tube wear. LRA Section 4.7.9 indicates the applicant's TLAA analyzes steam generator tube wear due to the impact/sliding motion of the tubes against their supports.

Issue:

LRA Section 4.7.9 indicates that the applicant's TLAA does not include tube-to-tube wear. The staff needs justification for why the applicant's TLAA does not include tube-to-tube wear.

Request:

Provide the applicant's technical basis for why the applicant's TLAA does not include tube-to-tube wear. As part of the response, confirm whether the plant-specific operating experience supports the applicant's technical basis.

Callaway Response

At the time the replacement steam generators were designed, tube-to-tube wear was not considered as a failure mechanism. Callaway evaluated the cited operating experience (OE). The steam generators in the cited OE are from a different manufacturer than Callaway's replacement steam generators (Mitsubishi vs. AREVA), and the plants have different NSSS designs (Westinghouse 4-Loop vs. CE 2-Loop). A review of the Callaway steam generator inspections verified that the tubes are not exhibiting signs of tube-to-tube proximity or contact. Also, a review of operating experience from other Westinghouse-style steam generators manufactured by AREVA manufactured around same time as Callaway's steam generators did not indicate that tube-to-tube wear was occurring. While not anticipated to occur at Callaway, Callaway is aware of the potential and the steam generator aging management program (XI.M19), discussed in LRA Appendix B2.1.9, provides a means to identify this aging mechanism should it begin to occur.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 4.7.9-4

Background:

The applicant's letter dated May 17, 2012, encloses "Callaway Energy Center Steam Generator Tube Inspection Report." Section 4.2, "Secondary Side Inspections" of the inspection report, in part, addresses sludge lancing of the steam generators, which was conducted during RFO 18 (corresponding to 4.1 effective full power years). Section 4.3.2 of the inspection report further indicates that sludge lancing was performed on all four steam generators and a combined total of 11 pounds of sludge was collected.

NRC Information Notice 2007-37, "Buildup of Deposits in Steam Generators," indicates that corrosion product accumulation in the tube support plate (TSP) holes can increase the vibration of the tubes. The staff also notes that the increase in tube vibration has adverse effect on steam generator tube wear.

In addition, the following reference indicates that the clogging of the broached holes of the TSPs may cause perturbation of the steam generator internal hydrodynamics, increase of local flow velocities, and flow-induced fretting (IAEA-TECDOC-1668, "Assessment and Management of Aging of Major Nuclear Power Plant Components Important to Safety: Steam Generators," 2011 Update, International Atomic Energy Agency, November 2011, pages 59, 72 and 73).

In comparison, LRA Section 4.7.9 does not clearly indicate whether the applicant's TLAA for steam generator tube wear considers the potential adverse effect of clogging of TSP holes on tube wear.

Issue:

The staff needs to clarify whether the applicant's TLAA considers the potential adverse effect of clogging of TSP holes or why the TLAA does not need to consider it.

Request:

Clarify whether the applicant's TLAA considers the potential adverse effect of clogging of TSP holes on steam generator tube wear. If the TLAA does not consider the adverse effect of clogging of TSP holes, provide justification for why the TLAA does not consider the adverse effect.

As part of the response, confirm whether the plant-specific operating experience supports the applicant's justification.

Callaway Response

The clogging of the holes at the tube support plate (TSP) is taken into account in the tube wear analysis. A clogged hole results in a reduced damping ratio for the vibratory system which is a penalizing effect.

The phenomenon is considered even though it is considered rather unlikely to occur. Actions have been taken to reduce the amount of corrosion products in the secondary side. The design of the replacement steam generator minimizes the potential for TSP clogging by the selection of stainless steel material for the tube support plate and the use of line support contact for the broached hole geometry. Secondary plant chemistry has been maintained within the chemistry guideline limits and corrosion transport has been significantly reduced since the replacement of the main condenser tubes in Refuel 13 (Spring 2004). Sludge lancing of all four replacement steam generators was performed in Refuel 18 (Fall 2011). This was the first time any of the replacement steam generators at Callaway were sludge lanced and only a minimal amount of sludge was removed from each.

In conclusion, clogging of the TSP is incorporated into the tube wear analysis. This is conservative because operating experience indicates that this condition is unlikely to occur.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 4.7.9-5

Background:

LRA Section 4.7.9 addresses the TLAA for replacement steam generator tube wear for the period of extended operation.

During the audit, the staff noted that Callaway Action Request (CAR) 200500411 describes the failure of a flow meter component due to flow accelerated corrosion (FAC) as addressed in RAI B2.1.7-6 (dated July 18, 2012). The staff also noted that the flow tube separated from its venturi throat, migrated down the pipe, and blocked the minimum recirculation flow line.

EPRI Report, TR-112118, “Nuclear Feedwater Flow Measurement Application Guide,” July 1999, indicates that venturi flow meters used to calculate feedwater flow rates in nuclear power plants are susceptible to aging-related degradation that can cause flow rate calculation errors. In addition, EPRI TR-112118 and the following references indicate that plants might enter overpower conditions due to non-conservative flow correction factors with respect to assessment of reactor power level (i.e., due to underestimation of the feedwater flow rate).

- Licensee Event Report 317-2005-003, Revision 1, “Overpower Condition Resulting from Non-conservative Flow Correction Factors,” December 14, 2005 (ADAMS Accession No. ML053540215)
- NSAL-03-12, “CROSSFLOW Ultrasonic Flow Measurement System Flow Signal Interference Issues,” Westinghouse Electric Company, December 5, 2003 (ADAMS Accession No. ML033421289)
- NRC Regulatory Issue Summary (RIS) 2007-24, “NRC Staff Position on Use of the Westinghouse CROSSFLOW Ultrasonic Flow Meter for Power Uprate or Power Recovery,” September 27, 2007 (ADAMS Accession No. ML063450261)

Issue:

Although the failed flow meter addressed in the CAR is not a feedwater venturi flow meter, the plant-specific and industry operating experience indicates that the feedwater venturi flow meter may be subject to similar aging degradation (e.g., FAC or corrosion product deposits). Therefore, the staff requires clarification as to whether the applicant’s TLAA adequately considers potential effects of flow rate calculation errors or flow correction factor errors on steam generator tube wear.

Request:

Provide additional information to clarify that the applicant’s TLAA adequately considers potential effects of flow rate calculation errors or flow correction factor errors that can accelerate steam generator wear through overpower conditions (i.e., due to underestimation of the feedwater flow rate).

Callaway Response

The analysis includes a 2% for measurement uncertainties. To ensure that the plant remains within this uncertainty, plant instrumentation undergoes periodic surveillance and calibration and the uncertainty is incorporated into the setpoints. Critical plant instrumentation whose failure could result in a violation of this uncertainty is incorporated into the plant’s Technical

Specification and/or procedures; therefore consideration of additional uncertainty is not required.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 3.2.1.19-2

Background:

SRP-LR Table 3.2.1, item 19 addresses stainless steel heat exchanger tubes exposed to treated water that are being managed for reduction of heat transfer due to fouling. In its LRA, the applicant states that this item is not applicable because there are no in-scope stainless steel heat exchangers exposed to treated water in the containment spray system.

The staff notes that although the GALL Report only cites an item from the containment spray system for consideration by PWRs, the material, environment, aging effect combination described by this item also applies to other engineered safety feature systems, such as the residual heat removal (RHR) system. The staff also notes that LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," discusses the inappropriate credit previously given to boron as a corrosion inhibitor, and states that aging effects such as reduction of heat transfer may not be adequately managed using the existing guidance. In addition, LR-ISG-2011-01 identifies the additional aging management review items for reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated borated water.

Issue:

Although LRA Section 2.1.5.2 states that LR-ISG-2011-01 is applicable to Callaway, it is not clear to the staff why there are no AMR items listed for the stainless steel tubes exposed to treated borated water that are being managed for reduction of heat transfer in LRA Table 3.2.2-6, RHR system for the RHR heat exchangers and the RHR pump seal-water coolers.

Request:

Provide information to justify that SRP-LR Table 3.2.1, item 19 is not applicable, and that no AMR items are needed to manage reduction of heat transfer for stainless steel heat exchanger tubes exposed to treated borated water in any of the engineering safety feature systems. Otherwise, provide additional AMR items, consistent with those listed in LR-ISG-2011-01, to ensure that these components are adequately managed for reduction of heat transfer.

Callaway Response

Consistent with LR-ISG-2011-01, the RHR Heat Exchangers and the RHR pump seal-water coolers have had reduction of heat transfer added as an aging effect for the stainless steel tubes exposed to treated borated water. This aging effect will be managed by the Water Chemistry program (B2.1.2) and the One-Time Inspection program (B2.1.18). LRA Table 3.2-1 item 19 has been revised to state that this is now consistent with NUREG-1801.

LRA Table 3.2.2-6 has been revised as shown on LRA Amendment 9, in Enclosure 2 to include the aging effect of reduction of heat transfer for the stainless steel tubes exposed to treated borated water. LRA Table 3.2-1 item 19 has been revised as shown on LRA Amendment 9, in Enclosure 2 to state that this item is now consistent with NUREG-1801.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, "Amendment 9, LRA Changes from RAI Responses," for a description of LRA changes with this response.

RAI 3.3.1.17-1

Background:

SRP-LR Table 3.3.1, item 17 and item 27 address stainless steel heat exchanger tubes exposed to treated water that are being managed for reduction of heat transfer due to fouling. In its LRA, the applicant states that these items are not applicable because they are only applicable to BWRs.

The staff notes that LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," discusses the inappropriate credit previously given to boron as a corrosion inhibitor, and states that aging effects such as reduction of heat transfer may not be adequately managed using the existing guidance. In addition, LR-ISG-2011-01 identifies the additional AMR items for reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated borated water.

Issue:

Although LRA Section 2.1.5.2 states that LR-ISG-2011-01 is applicable to Callaway, it is not clear to the staff why there are no AMR items listed for the stainless steel heat exchanger tubes exposed to treated borated water that are being managed for reduction of heat transfer in LRA Table 3.3.2-2, "Auxiliary Systems -Summary of Aging Management Evaluation -Fuel Pool Cooling and Cleanup System," and Table 3.3.2-10, "Auxiliary Systems -Summary of Aging Management Evaluation -Chemical and Volume Control System."

Request:

Provide information to justify that SRP-LR Table 3.3.1, item 17 is not applicable, and that no AMR items are needed to manage reduction of heat transfer for stainless steel heat exchanger tubes exposed to treated borated water in any of the engineering safety features systems. Otherwise, provide additional AMR items, consistent with those listed in LR-ISG-2011-01 ,to ensure that these components are adequately managed for reduction of heat transfer.

Callaway Response

Consistent with LR-ISG-2011-01, the Fuel Pool Cooling Heat Exchangers and the CVCS Seal Water Return Heat Exchangers have had reduction of heat transfer added as an aging effect for the stainless steel tubes exposed to treated borated water. This aging effect will be managed by the Water Chemistry program (B2.1.2) and the One-Time Inspection (B2.1.18). LRA Table 3.3-1, item 17 has been revised to state that this is now consistent with NUREG-1801.

LRA Tables 3.3.2-2 and 3.3.2-10 have been revised as shown on LRA Amendment 9, in Enclosure 2 to include the aging effect of reduction of heat transfer for the stainless steel tubes exposed to treated borated water. LRA Table 3.3-1 item 17 has been revised as shown on LRA Amendment 9, in Enclosure 2 to state that this item is now consistent with NUREG-1801.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, "Amendment 9, LRA Changes from RAI Responses," for a description of LRA changes with this response.

Amendment 9, LRA Changes from RAI Responses

Enclosure 2 Summary Table

Affected LRA Section	LRA Page
Table 3.0-1	3.0-10
Table 3.1.2-2	3.1-83
Table 3.2.2-1	3.2-34
Table 3.2.2-5	3.2-54
Table 3.3.2-2	3.3-86
Table 3.3.2-10	3.3-123
Table 3.3.2-28	3.3-271
Table 3.2-1	3.2-19
Table 3.2.2-6	3.2-72
Table 3.3-1	3.3-44
Table 3.3.2-2	3.3-88
Table 3.3.2-10	3.3-135
Table 3.3.2-2	3.3-86
Table 4.1-1	4.1-4 and 4.1-5
Section 4.7.3	4.7-7 and 4.7-8
Section 4.7.9	4.7-15
Section A3.6.3	A-33
Section A3.6.9	A-35

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Added Plant Indoor Air (When used as Internal) as an internal environment.

Table 3.0-1, Mechanical Environments, (page 3.0-10) is revised as follows (new text shown underlined):

Table 3.0-1 Mechanical Environments

Mechanical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
<u>Plant Indoor Air (When used as Internal)</u>	<u>Air – Indoor Uncontrolled (Internal/External)</u>	<u>Indoor air with temperatures higher than the dew point. Condensation can occur, but only rarely; equipment surfaces are normally dry.</u>

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Added a new line item to account for loss of material due to pitting and crevice corrosion for stainless steel bolting in an environment of plant indoor air (external). No new Plant Notes are added.

Table 3.1.2-2, Reactor Coolant System (page 3.1-83), Table 3.2.2-1, Containment Spray System (page 3.2-34), Table 3.2.2-5, High Pressure Coolant Injection System (page 3.2-54), Table 3.3.2-2, Fuel Pool Cooling and Cleanup System (page 3.3-86), Table 3.3.2-10, Chemical and Volume Control System (page 3.3-123), and Table 3.3.2-28, Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2) (page 3.3-271), are revised as follows (new text shown underlined):

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Coolant System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	VII.I.AP-125	3.2.1.012	A

Table 3.2.2-1 Engineered Safety Features – Summary of Aging Management Evaluation – Containment Spray System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	PB	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	VII.I.AP-125	3.2.1.012	A

Table 3.2.2-5 Engineered Safety Features – Summary of Aging Management Evaluation – High Pressure Coolant Injection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	V.E.EP-70	3.2.1.013	A

Table 3.3.2-2 Auxiliary Systems – Summary of Aging Management Evaluation – Fuel Pool Cooling and Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	VII.I.AP-125	3.3.1.012	A

Table 3.3.2-10 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	VII.I.AP-125	3.3.1.012	A

Table 3.3.2-28 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Closure Bolting	LBS	Stainless Steel	Plant Indoor Air (Ext)	Loss of material	Bolting Integrity (B2.1.8)	VII.I.AP-125	3.3.1.012	A

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Revise to add reduction of heat transfer as an aging effect for stainless steel heat exchanger components that have the heat transfer function and are exposed to treated borated water.

Table 3.2-1, Summary of Aging Management Programs in Chapter V of NUREG-1801 for Engineered Safety Features (page 3.2-19), is revised as follows (deleted text shown with strikethrough and new text shown underlined).

Table 3.2-1 Summary of Aging Management Programs in Chapter V of NUREG-1801 for Engineered Safety Features

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1.019	Stainless steel Heat exchanger tubes exposed to Treated water (borated)	Reduction of heat transfer due to fouling	Water Chemistry (B2.1.2), and One-Time Inspection (B2.1.18)	No	Consistent with NUREG-1801.~~Not applicable. Callaway has no in-scope stainless steel heat exchanger tubes exposed to treated water in the containment spray system, so the applicable NUREG-1801 line was not used.~~

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Table 3.2.2-6, Engineered Safety Features – Summary of Aging Management Evaluation – Residual Heat Removal System (page 3.2-72), is revised as follows (new text shown underlined).

Table 3.2.2-6 Engineered Safety Features – Summary of Aging Management Evaluation – Residual Heat Removal System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Residual Heat Removal)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Reduction of heat transfer	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)	V.D1.E-20	3.2.1.019	A
Heat Exchanger (RHR Pump Seal Water Cooler)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Reduction of heat transfer	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)	V.D1.E-20	3.2.1.019	A

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Table 3.3-1, Summary of Aging Management Programs in Chapter VII of NUREG-1801 for Auxiliary Systems (page 3.3-44), is revised as follows (deleted text shown with strikethrough and new text shown underlined).

Table 3.3-1 Summary of Aging Management Programs in Chapter VII of NUREG-1801 for Auxiliary Systems

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1.017	Stainless steel Heat exchanger tubes exposed to Treated water, Treated borated water	Reduction of heat transfer due to fouling	Water Chemistry (B2.1.2), and One-Time Inspection (B2.1.18)	No	Consistent with NUREG-1801.~~Not applicable – BWR only~~

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Table 3.3.2-2, Auxiliary Systems – Summary of Aging Management Evaluation – Fuel Pool Cooling and Cleanup System (page 3.3-88), is revised as follows (new text shown underlined).

Table 3.3.2-2 Auxiliary Systems – Summary of Aging Management Evaluation – Fuel Pool Cooling and Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Fuel Pool Cooling)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Reduction of heat transfer	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)	VII.A3.A-101	3.3.1.017	A

Table 3.3.2-10, Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System (page 3.3-135), is revised as follows (new text shown underlined).

Table 3.3.2-10 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (CVCS Seal Water Return)	HT, PB	Stainless Steel	Treated Borated Water (Int)	Reduction of heat transfer	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)	VII.E1.A-101	3.3.1.017	A

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Revised the line for the expansion joint of the sleeve surrounding the fuel transfer tube. The environment was changed from borated water leakage to plant indoor air, and the NUREG-1801 item was changed from VII.J.AP-18 to V.F.EP-82. In addition, the external environment of the fuel transfer tube was changed to plant indoor air.

Table 3.3.2-2, Fuel Pool Cooling and Cleanup System (pages 3.3-86) is revised as follows (new text shown underlined and deleted text shown in strikethrough):

Table 3.3.2-2 Auxiliary Systems – Summary of Aging Management Evaluation – Fuel Pool Cooling and Cleanup System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Expansion Joint	ES	Stainless Steel	~~Borated Water Leakage (Int)~~ <u>Plant Indoor Air (Int)</u>	None	None	~~VII.J.AP-18~~ <u>V.F.EP-82</u>	~~3.3.1.120~~ <u>3.2.1.063</u>	A<u>, 2</u>
Fuel Transfer Tube	PB	Stainless Steel	~~Borated Water Leakage (Ext)~~ <u>Plant Indoor Air (Ext)</u>	None	None	~~VII.J.AP-18~~ <u>VII.J.AP-17</u>	3.3.1.120	A<u>, 2</u>

<u>Notes for Table 3.3.2-2:</u>

<u>Standard Notes:</u>
A Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.

E Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.

Plant Specific Notes:

1 The One-Time Inspection program (B2.1.18) is used to verify the effectiveness of the Water Chemistry program (B2.1.2) to manage these aging effects.

2 This evaluation is applicable to the component surfaces between the fuel transfer tube and the sleeve that encloses the fuel transfer tube. The sleeve that encloses the fuel transfer tube is evaluated as a generic structural component.

Table 4.1-1 List of TLAAs

TLAA Category	Description	Disposition Category(i)	Section
1.	**Reactor Vessel Neutron Embrittlement Analysis**	**N/A**	**4.2**
	Neutron Fluence Values	ii	4.2.1
	Charpy Upper-Shelf Energy	ii	4.2.2
	Pressurized Thermal Shock	ii	4.2.3
	Pressure-Temperature (P-T) Limits	iii	4.2.4
	Low Temperature Overpressure Protection	iii	4.2.5
2	**Metal Fatigue**	**N/A**	**4.3**
	Fatigue Monitoring Program	N/A	4.3.1
	ASME Section III Class I Fatigue Analysis of Vessels, Piping and Components	iii	4.3.2
	Reactor Coolant Pump Thermal Barrier Flange	iii	4.3.2.1
	Pressurizer Insurge-Outsurge Transients	iii	4.3.2.2
	Steam Generator ASME Section III Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses	i	4.3.2.3
	NRC Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification	iii	4.3.2.4
	ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals	iii	4.3.3
	Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)	iii	4.3.4
	Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ANSI B31.1 and ASME Section III Class 2 and 3 Piping	i	4.3.5
	Fatigue Design of Spent Fuel Pool Liner and Racks for Seismic Events	i	4.3.6
	Fatigue Design and Analysis of Class 1E Electrical Raceway Support Angle Fittings for Seismic Events	i	4.3.7

TLAA Category	Description	Disposition Category[i]	Section
	Fatigue Analyses of Class 2 Heat Exchangers	ii, iii	4.3.8
3.	**Environmental Qualification (EQ) of Electric Equipment**	**iii**	**4.4**
4.	**Concrete Containment Tendon Prestress**	**i, ii**	**4.5**
5.	**Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses**	**N/A**	**4.6**
	Design Cycles for the Main Steam Line and Feedwater Penetrations	i, ii	4.6.1
	Fatigue Waiver Evaluations for the Access Hatches and Leak Chase Channels	i	4.6.2
6.	**Other Plant-Specific Time-Limited Aging Analyses**	**N/A**	**4.7**
	Containment Polar Crane, Fuel Building Cask Handling Crane, Spent Fuel Pool Bridge Crane, and Refueling Machine CMAA 70 Load Cycle Limits	i	4.7.1
	In-service Flaw Analyses that Demonstrate Structural Integrity for 40 years	i	4.7.2
	Corrosion Analysis of the Reactor Vessel Cladding Indications	i	4.7.3
	Reactor Vessel Underclad Cracking Analyses	i	4.7.4
	Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis	i	4.7.5
	High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factors	iii	4.7.6
	Fatigue Crack Growth Assessment in Support of a Fracture Mechanics Analysis for the Leak-Before-Break (LBB) Elimination of Dynamic Effects of Piping Failures	i	4.7.7
	Replacement Class 3 Buried Piping	i	4.7.8
	Replacement Steam Generator Tube Wear	iii	4.7.9

[i]
(i) 10 CFR 54.21(c)(1)(i), Validation: The analyses remain valid for the period of extended operation.
(ii) 10 CFR 54.21(c)(1)(ii), Projection: The analyses have been projected to the end of the period of extended operation.
(iii) 10 CFR 54.21(c)(1)(iii), Aging Management: The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.
N/A Not Applicable: Section heading or no TLAA. Disposition categories are not applicable.

4.7.3 Corrosion Analysis of the Reactor Vessel Cladding Indications

FSAR Section 5.2.3.2.2 SP identifies two areas where the reactor pressure vessel low-alloy steel has been left exposed to the reactor coolant. The first area is 1.5 in. x 0.75 in. and is located between penetrations #54 and 58 and approximately 6 inches above the penetrations. The second area is 0.53 in. x 0.3 in. and is located approximately 4 in. above penetration #51. The existence of these areas has been evaluated as acceptable.

The first area was identified during Refuel 13 (Spring 2004) while performing bottom mounted instrumentation inspections inside the reactor pressure vessel, when a small rust colored mark was identified on the lower reactor vessel wall. The rust stain is indicative of exposed low-alloy steel. These findings support the characterization of this indication as an area where the cladding is missing. This indication was determined to be acceptable with IWB-3510.1(d) which states that indications entirely within the cladding are acceptable.

The second area was identified during Refuel 15 (Spring 2007). The flaw was characterized as the same type of flaw identified during Refuel 13 and the analysis, calculation BB-183 (Reference 11), was updated to include both flaws within the scope of its structural integrity evaluation.

The evaluation demonstrated that the ASME Code criteria will continue to be met relative to the corrosion exposure area and vessel minimum wall thickness. The corrosion evaluation compared the exposed area of the reactor pressure vessel low-alloy steel, 1.5 in. x 0.625 in. and 0.53 in. x 0.3 in., to the NB-3332.1 acceptance criteria for openings not requiring reinforcement, 4.356 in. diameter. This limit would not be approached even when considering the metal would experience 0.119 in. of corrosion. The evaluation considered a plant life of 40 years, which includes 20 years under the current license plus 20 years for plant life extension. The amount of corrosion was calculated assuming a corrosion rate of 0.001 in/yr for normal operating conditions; an outage corrosion rate of 0.015 in/yr with the average outage duration of less than 8 weeks every 18 months; and a 2-week startup period after each outage with a corrosion rate of 0.010 in./yr. The corrosion rates are from EPRI Technical Report, *Boric Acid Corrosion Guidebook*, Revision 1."

If an outage corrosion rate was assumed for the entire 40 years, the metal would experience 0.6 in. of corrosion and the diameter of the damaged area would still be is much less than the allowable diameter.

The vessel minimum wall thickness evaluation demonstrated that the wall thickness, 5.38 in., minus the maximum degraded area depth, 0.28 in., meets the criterion of NB-3324.2, 4.329 in. It is assumed that the vessel wall thickness of 5.38 in. includes the nominal cladding thickness of 0.22 in. The ultrasonic testing indicated a maximum defect depth of 0.14 in. from the inner surface, but the evaluation assumes that the low-allow base metal depth is reduced by an additional 0.14 in. The 0.28 in. defect depth bounds the measured indications plus the calculated maximum 40 year corrosion loss of 0.119 in. Even if the outage corrosion rate was assumed for 40 years, the resulting wall loss would be only 0.6 in. A 0.6 in. wall loss added to the larger assumed defect depth of 0.28 inches would still leave the reactor wall thickness at 4.5 inches (5.38 inches – 0.28 inches - 0.6 inches =

4.5 inches). This still satisfies the minimum wall thickness requirement based on the criterion of NB-3324.2 of 4.329 in.

Visual inspections of the flaws are performed when the opportunity permits, but the inspection frequency and characterization of the indications will not change as the evaluation determined that frequent inspections of the damaged area would not be required.

The corrosion analysis includes the period of extended operation. Therefore the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Disposition: Validation, 10 CFR 54.21(c)(1)(i)

4.7.9 Replacement Steam Generator Tube Wear

For the replacement steam generators (RSG) the time-averaged wear work rates at the tube support locations were analyzed due to the impact/sliding motion of the tubes against their supports. This analysis assumed a cumulative operating service of 45 years and compared the calculated wear of 0.010 in. to the maximum allowable wear of 40 percent of the tube wall thickness, 0.0156 in. Since analysis is dependent on the 45-year RSG design life, it is a TLAA.

~~The 45-year design life of the RSG tubes extends beyond the period of extended operation. Therefore, the design of the RSG tubes, is valid through the period of extended operation and the corresponding TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).~~

The steam generator aging management program, discussed in LRA Appendix B2.1.9 manages wall thinning of the steam generator tubes. The program justifies the continued operation of all wear indications through the next scheduled inspection, typically 3 cycles, by establishing a wear rate based on measured data to ensure tube wear does not exceed 40% of the through-wall thickness. Therefore, this TLAA will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Disposition: ~~Validation~~Management**, 10 CFR 54.21(c)(1)(i**ii**)**

A3.6.3 Corrosion Analysis of the Reactor Vessel Cladding Indications

Two areas where identified during Refuel 13 (Spring 2004) and Refuel 15 (Spring 2007) where the reactor pressure vessel low-alloy steel has been left exposed to the reactor coolant. The evaluation demonstrated that the ASME Code criteria will continue to be met relative to the corrosion exposure area (NB-3332.1) and vessel minimum wall thickness (NB 3324.2) after corrosion is considered. The evaluation considered a plant life of 40 years, which includes 20 years under the current license plus 20 years for the period of extended operation. The corrosion analysis includes the period of extended operation. Therefore the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.6.9 Replacement Steam Generator Tube Wear

The replacement steam generator tube wear analysis determined the maximum wear for a 45-year design life would remain below the maximum allowable wear of 40 percent of the tube wall thickness. ~~The 45-year design life of the replacement steam generator tubes extends beyond the period of extended operation. Therefore, the design of the replacement steam generator tubes is valid through the period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).~~ The steam generator aging management program justifies the continued operation of all wear indications through the next scheduled inspection by establishing a wear rate based on measured data to ensure tube wear does not exceed 40% of the through-wall thickness. Therefore, this TLAA will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).