CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

REQUEST FOR ADDITIONAL INFORMATION (RAI) Set #5 RESPONSES

## RAI B2.1.1-1

Background:

License renewal application (LRA) Section B2.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," states that, "[t]he ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program manages cracking, loss of fracture toughness, and loss of material." It further states that, "[t]he ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program has been proven within the industry to maintain component structural integrity and ensure that aging effects are discovered and repaired before the loss of component intended function."

NUREG-1801, "Generic Aging Lessons Learned Report," (GALL Report) aging management program (AMP) XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," "detection of aging effects" program element states that "[t]he extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component." In addition, "monitoring and trending" program element states that, "[f]or Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation."

Issue:

The staff reviewed the applicant's Inservice Inspection Summary Reports dated from 1999 to 2012 and noted that degradation including pin hole leaks in the site's essential service water (ESW) system piping have been detected. Leaks have also been detected in the chemical and volume control system letdown piping. During the onsite audit of the Inservice Inspection Program, the staff reviewed documents indicating that, for mitigative measures, the applicant enhanced its water chemistry control and replaced some of the degraded piping with more corrosion resistant stainless steel piping during the current 10-year inservice inspection (ISI) interval, which commenced on December 19, 2004. However, based on recent inspection results, as documented in the Inservice Inspection Summary Reports during the current 10-year ISI interval, the staff noted that there was more piping degradation detected and repaired, indicating the degradation had not been alleviated. In addition, during its onsite audit, the staff reviewed documents indicating that there is still an extensive amount of carbon steel piping in the system that is susceptible to similar degradation. Therefore, the staff lacks sufficient information to conclude that the AMPs "detection of aging effects" program element will be effective in timely detection of aging effects, and the "monitoring and trending" program element will be effective in providing timely corrective or mitigative activities to adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) during the period of extended operation.

Request:

Justify the ISI Program's effectiveness in timely detection of aging effects and identification or prediction of loss of material before through-wall leakage has occurred. Discuss corrective actions to demonstrate the program's effectiveness in addressing ongoing degradation concerns.

**<u>Callaway Response</u>**

The majority of the leaks identified in the Inservice Inspection Summary Reports for 1999 to 2012 have been in the essential service water (ESW) system. Most of these leaks were caused or exacerbated by microbiological corrosion (MIC) of carbon steel surfaces. The following is a list of those leaks (note that the refueling number and date refer to the Inservice Inspection Summary Report, and not the date when the leaks were discovered).

RF10 – Fall, 1999
Two pinhole leaks occurred in an 8 inch carbon steel line.
A pinhole leak occurred in a 3 inch carbon steel line at weld.
A pinhole leak occurred in a 4 inch carbon steel line.

RF11 – Spring, 2001
A pinhole leak occurred in a 6 inch carbon steel line.

RF14 – Fall, 2005
A pinhole leak occurred in a 30 inch carbon steel line.
A leak occurred in a 4 inch carbon steel line.

In order to reduce the effect of MIC on carbon steel piping in the ESW system, a strategy was initiated in the early 1990s to add bromine/chlorine as a biocide and to add a biopenetrant to slowly soften and remove nodules. Later, targeted biopenetrant and biocide treatments were begun on a monthly basis to ESW piping during pump runs to further treat and protect the safety related equipment and piping.

In addition, a program was begun in 2003 to replace all the small-bore (4 inch and less) and selected sections of larger-bore carbon steel piping with stainless steel. Nearly 3400 feet of carbon steel piping have been replaced with stainless steel, including all the small-bore piping identified above with leaks. No leaks have occurred in the stainless steel piping.

From 2008 to 2009, the buried portions of the ESW supply from the ESW pump house and return to the ultimate heat sink cooling tower were replaced with high-density polyethylene (HDPE) piping.

The 2010 Inservice Inspection Summary Report identified a section of 30 inch ESW piping which was replaced. In this case, an inspection found the loss of material prior to the occurrence of through-wall leakage.

There have been no leaks in the ESW piping due to MIC recorded in the Inservice Inspection Summary Reports since 2005. This demonstrates that corrective action taken to address leaks in the ESW system caused by MIC has been effective.

Other plant programs, such as the Raw Water Systems Predictive Performance Program and the Microbiologically Influenced Corrosion Monitoring Program, are effectively identifying and correcting MIC issues in the ESW system prior to them needing to be addressed by the Inservice Inspection Program. See the response to RAI B2.1.10-6 for additional information on ESW operating experience and associated corrective actions.

In addition to the ESW leaks caused by MIC, the Inservice Inspection Summary Reports for 1999 to 2012 documented several other leaks.

RF10 – Fall, 1999
A pinhole leak occurred in an ESW drain line from the Component Cooling Water heat exchanger. The cause of the leak was a cracked weld due to vibration, not MIC. This weld was exempt from examination since it met the criteria of ASME Section XI, IWD-1220.

RF11 – Spring, 2001
Leaks were found in the ESW pump pre-lube storage tank B. The cause of the leaks was external corrosion due to maintenance. These leaks were not at a weld, so they were not at a location that would have been inspected by the ISI program.

Also in the RF11 Inservice Inspection Summary Report, a component cooling water leak occurred in a weld upstream of the relief valve for the component cooling water side of the letdown heat exchanger. The primary cause of the crack in the weld was thermal expansion stresses. This weld was exempt from examination since it met the criteria of ASME Section XI, IWC-1220.

RF16 – Fall, 2008
A treated borated water leak occurred in a 2 inch pressurizer auxiliary spray line. The cause was OD-initiated stress corrosion cracking promoted by the presence of chlorides, operating stresses due to pressure/temperature changes, or residual stresses due to stress concentration points in pitting corrosion areas under hangers. This leak was not at a weld, so it was not at a location that would have been inspected by the ISI program.

RF18 – Fall, 2011
A treated borated water leak occurred at the downstream weld of the B CVCS letdown orifice outlet throttle valve. This valve had been replaced shortly before the leak developed. The apparent cause was a weld flaw. This weld was also exempt from examination in the ISI program since it met the criteria of ASME Section XI, IWC-1220.

As can be seen from the description above, there have been only five leaks in the 12 years from 1999 to 2011 reported in the Inservice Inspection Summary Reports for this period, other than the leaks in the ESW system caused by MIC. These leaks have been unique, with no clear trend regarding causes. None of these leaks were in locations that required a surface or volumetric examination by the ISI program.

The above operating experience provides objective evidence that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program inspection methods are capable of managing aging effects. Occurrences that would be identified under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will be evaluated to assure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for re-evaluation, repair, or replacement is provided for locations where aging is found. There is confidence that the continued implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will effectively identify aging prior to loss of intended function.

## Corresponding Amendment Changes

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

## RAI B2.1.3-1

Background:

Aging management of the Callaway reactor pressure vessel (RPV) head closure stud bolting (including flange stud hole threads, studs, nuts, and washers) is being managed, in part, using the LRA AMP B2.1.3, “Reactor Head Closure Stud Bolting” program, which is an AMP that is based on conformance with the recommended program elements in GALL Report AMP XI.M3, “Reactor Head Closure Stud Bolting.”

During the review of the LRA and the audit of the applicant’s operating experience for the AMP, the staff noted that the Callaway plant had several occasions where RPV closure studs had been found to be stuck during stud insertion or removal activities. In some cases the studs had to be either cut or forcibly removed from their RPV flange stud hole locations. In addition, during the audit the staff noted that there are also numerous cases where the RPV lower flange stud holes have had damaged threads, or if the thread regions were repaired, had fewer threads than were originally designed.

Issue:

Section A.1.2.1, Item 7, of NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR) states that “[t]he applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown.” The stuck studs or damaged threads were detected during plant refueling or cold shutdown activities and the amount of damaged threads was only determined after the studs were removed from the RPV flange stud hole locations. Therefore, for studs that are stuck in place, the staff is concerned that the examinations performed in accordance with the Reactor Head Closure Stud Bolting program may not be capable of detecting wear or damage in the stud holes or quantifying the amount of wear or damage in the stud holes. In addition, for studs that are stuck in place, the staff is also concerned that there may be some potential for boric acid corrosion to occur in the stud areas with engaged threads or stud hole areas below the stud bottom faces.

Request:

For stuck studs left in place, clarify how the program will detect loss of material due to wear or corrosion (including potential boric acid corrosion) and will quantify the potential amount of damage in areas of the studs and lower flange (including engaged threaded regions and remaining stud hole areas below the stud bottom faces).

## Callaway Response

Callaway has only one reactor vessel head closure stud which is stuck. Stud #18 became stuck in 1996, 2.625 inches above the base of the stud hole, which provides 6.505 inches of thread engagement. Since the minimum required thread engagement length is 6.31 inches, stud #18 exceeds the requirement for minimum thread engagement.

An inspection of the stud prior to reactor vessel head installation found a small burr on the 10th and 11th threads. The burr was removed, and there were no other problems with the stud threads. The stud hole threads were also inspected, and no damage was found. When the stud became stuck, excessive force was not used in an attempt to force it the remaining 2.625 inches or to remove it. Therefore, it is believed that no thread damage was caused by actions taken after the stud became stuck. When the stud is de-tensioned in preparation for refueling, a stress of 65,000 psi is successfully applied, which provides further evidence that there is no thread damage. The stress during normal operation is approximately 39,400 psi.

During refuelings, stud #18 is protected from exposure to the borated water in the refueling pool by an encapsulation to prevent corrosion due to boric acid. If it is suspected that the encapsulation leaked, it would be addressed through the corrective action program.

Callaway performs inspections of stud #18 as required by the ASME Section XI Code. These inspections include a volumetric examination of the flange threads and the stud, and a VT-1 examination of the surfaces of the nuts and washers. A VT-2 examination is performed after each refueling to check for system leaks.

Based on the above discussion, it is believed that stud #18 has adequate thread engagement, and that the ongoing actions of 1) preventing exposure of the threads to borated water, 2) performing inspections required by the ASME Section XI Code, and 3) applying a stress during refueling outages which is well above the stress which the stud experiences during normal operation, will ensure that stud #18 will continue to perform its intended function.

## Corresponding Amendment Changes

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

## RAI B2.1.3-2

Background:

The “operating experience” program element for LRA AMP B2.1.3, “Reactor Head Closure Stud Bolting” program, states that there were multiple instances of stuck studs. The AMP’s “operating experience” program element also states that currently there is a stud which has been stuck since 1996, and is only partially engaged. During the audit, the staff also noted that there are additional RPV flange stud holes which may have damaged threads. Specifically, the staff noted that the RPV flange stud hole location Nos. 2, 4, 5, 7, 9, 14, 18, 20, 25, 39, 53, and 54 have or may have missing or damaged threads. This represents more than 20 percent of the applicant’s total number of the RPV closure stud bolting.

Issue:

Callaway’s RPV flange assembly and its bolting components are categorized as American Society of Mechanical Engineers (ASME) Code Class 1 reactor coolant pressure boundary (RCPB) components. The assembly is designed to appropriate design requirements for reactor vessel mechanical assemblies in Subsection NB of the 1971 Edition of ASME Boiler and Pressure Vessel Code, Section III (ASME Section III), Division 1.

The number of issues with stuck studs or damaged stud hole locations represents more than 20 percent of the total number of the RPV closure stud locations in the RPV flange assembly. Based on the staff’s review of the documents associated with the applicant’s operating experience, the staff was unable to verify whether the entire RPV flange assembly was reassessed every time a new RPV stud or stud hole issue arose, or whether the evaluation of the entire flange assembly had accounted for the collective impact of all RPV lower flange hole or stud degradation experience to date. Thus, the staff is uncertain as to how “monitoring and trending” is accomplished at the site with respect to this AMP, including how the current condition of the studs, stud holes and flange would be evaluated and reconciled to the design requirements for the flange assembly, as specified in the 1971 Edition of ASME Code Section III.

Request:

a) Identify all RPV flange assembly studs or stud hole locations that have had past experience with stuck studs, damage, or missing stud/stud hole threads. For each location, identify when the issue was first detected, and summarize the corrective actions that were taken to resolve the issue.

b) Clarify how the AMP performs “monitoring and trending” of relevant operating experience. Include in your clarification, an explanation of the type of evaluations that will be performed in individual stud or stud hole problems that are detected at the plant (e.g., stuck studs, or studs or stud holes with damaged or missing threads) and of the entire RPV flange based on the latest configuration of the flange assembly (i.e., studs, stud holes, threads, etc.). Clarify how the evaluations will be used to reconcile the latest, as-known configuration of the RPV flange assembly against applicable ASME Code Section III design requirements.

## Callaway Response

a) The following summarizes the problems encountered with the reactor vessel head closure studs and stud holes.

Stud #2 could not be removed in Refuel 2 (fall, 1987). It stuck at an elevation between four and five inches withdrawn. Vendor support could not be obtained in Refuel 2 to remove the stud, so it was left installed during the subsequent operating cycle. Because of its height, it could not be tensioned, so an evaluation was performed to allow operation with this stud detensioned. It was destructively removed in Refuel 3 (spring, 1989). Removal of the stud damaged some threads in the stud hole, and 13.1 threads were removed.

Stud #4 could not be removed in Refuel 2 (fall, 1987). It was stuck at a nearly fully inserted position. Vendor support could not be obtained in Refuel 2 to remove the stud, so it was left installed during the subsequent operating cycle. Since it was nearly fully inserted, it was able to be tensioned for operation. It was destructively removed in Refuel 3 (spring, 1989). Removal of the stud damaged some threads in the stud hole, and 6 threads were removed.

Stud #5 could not be removed in Refuel 2 (fall, 1987). It was stuck at a nearly fully inserted position. Vendor support could not be obtained in Refuel 2 to remove the stud, so it was left installed during the subsequent operating cycle. Since it was nearly fully inserted, it was able to be tensioned for operation. It was destructively removed in Refuel 3 (spring, 1989). Removal of the stud damaged some threads in the stud hole, and 7.9 threads were removed.

Stud #7 could not be removed in Refuel 1 (spring, 1986). It was stuck in a nearly fully inserted position. It remained stuck until Refuel 3 (spring, 1989), when it was destructively removed in Refuel 3 (spring, 1989). It was tensioned during operating cycles 2 and 3. Removal of the stud damaged some threads in the stud hole, and 4 threads were removed.

Stud #9 could not be removed in Refuel 2 (fall, 1987). It was stuck at a nearly fully inserted position. Vendor support could not be obtained in Refuel 2 to remove the stud, so it was left installed during the subsequent operating cycle. Since it was nearly fully inserted, it was able to be tensioned for operation. It was destructively removed in Refuel 3 (spring, 1989). Removal of the stud damaged some threads in the stud hole, and 13.3 threads were removed. In Refuel 5 (spring, 1992), additional thread damage was discovered in the stud hole, and an addition 1.82 threads were removed.

Stud hole #13 had 0.71 threads removed in Refuel 5 (spring, 1992).

Stud #18 could not be removed in Refuel 8 (fall, 1996). It was stuck at a height of 2 5/8 inches withdrawn. This height provides sufficient thread engagement to allow the stud to be tensioned. It has not yet been removed, and is tensioned during operating cycles.

Stud #24 was replaced in Refuel 2 (fall, 1987) due to minor thread damage.

Stud hole #25 had 0.66 threads removed in Refuel 5 (spring, 1992).

Stud hole #39 had 1 thread removed in Refuel 5 (spring, 1992).

Stud #42 was replaced in Refuel 2 (fall, 1987) due to minor thread damage.

Stud #53 was replaced in Refuel 2 (fall, 1987) due to minor thread damage. Stud hole #53 had 9 threads removed in Refuel 3 (spring, 1989).

Stud hole #54 had 0.6 threads removed in Refuel 5 (spring, 1992).

b) The Reactor Head Closure Stud Bolting program owner monitors operating experience associated with reactor head closure studs, nuts, and stud holes such as repairs, replacements, prior evaluations/calculations and documented aging effects. Evaluations of reactor vessel head closure stud and stud hole problems, such as stuck studs or missing threads, are initiated through use of the Callaway corrective action program. Inputs to the evaluations consider all relevant information, including ASME Code requirements, the latest vendor calculations, and operating experience such as repairs, replacements, prior evaluations and documented aging effects. These evaluations, including selection of appropriate inputs, are performed in accordance with applicable Callaway procedures for repairs, design changes or calculations, as appropriate for the disposition.

## Corresponding Amendment Changes

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

## RAI B2.1.5-1

Background:

The applicant's program evaluation report describes the program elements of the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5).

The "parameters monitored/inspected" program element described in the applicant's evaluation report indicates that RCPB cracking and leakage are monitored by the applicant's ISI program as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in Title 10, Section 50.55a, of the *Code of Federal Regulations* (CFR). In addition, the applicant's third interval ISI plan indicates that the ASME Code Cases N-722-1, N-729-1, and N770-1 are the code cases used in the applicant's ISI in accordance with 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

Issue:

ASME Code Case N-770-1 specifies visual examination to detect the reactor coolant leakage and boric acid corrosion associated with Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds. During the audit, the staff noted that the applicant's procedure for boric acid walkdown and the third-interval examination schedule for the applicant's ISI program plan do not clearly indicate the implementation of visual examination specified in ASME Code Case N-770-1.

Request:

Clarify why the applicant's implementing procedure for boric acid walkdown and examination schedule for ISI do not clearly indicate the implementation of visual examination specified in ASME Code Case N-770-1.

As part of the response, confirm whether the implementing procedures or examination schedules of ISI adequately implement visual examination, as specified in Inspection Items A-1 and A-2 of ASME Code Case N-770-1 [i.e., unmitigated butt welds at hot leg operating temperatures to be examined by visual examination each refueling outage (RFO)].

## Callaway Response

Attachment 8 of procedure EDP-ZZ-04070 Appendix A, "Alloy 600 Management Plan" provides guidance for ASME Code Case N-770-1 examination requirements for the different ASME Class 1 Alloy 82/182 dissimilar metal butt welds.

The visual examinations specified in ASME Code Case N-770-1 for Item Numbers A-1, A-2, and B are the same visual examinations specified in ASME Code Case N-722-1 Item Number B15.90 and B15.95. The schedule for N-722-1 visual examinations is identified in the Third Interval ISI Program Plan Appendix D.

The following procedures are being enhanced to reference implementation and scheduling of ASME Code Case N-770-1 as applicable for implementation and scheduling of visual examinations:

- QCP-ZZ-05048, Boric Acid Walkdown for RCS Pressure Boundary,
- QCP-ZZ-05041, Visual Examination to ASME VT-2,
- Third Interval ISI Program Plan Appendix D

**<u>Corresponding Amendment Changes</u>**

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

## RAI B2.1.5-2

Background:

The applicant's program evaluation report describes the program elements of the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5). The "detection of aging effects" program element described in the evaluation report indicates that the program includes examinations in accordance with the requirements of ASME Code Section XI, as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

During the audit, the staff noted that the applicant's implementing procedure for boric acid walkdown for the reactor coolant system pressure boundary includes the visual examination to detect reactor coolant leakage and boric acid corrosion.

Issue:

During the audit, the staff also noted that applicant's operating experience indicates that refueling cavity seal leakage caused a potential to interfere with the visual examinations of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument penetrations.

The staff needs to confirm whether the applicant's operating experience indicates any other previous or current leakage that may interfere with the visual examination of the reactor vessel nozzles specified in ASME Code Case N-770-1 and the other RCPB components specified in Code Case N-722-1.

In addition, the applicant's implementing procedure for boric acid walkdown for the reactor coolant system does not clearly address how the applicant's procedure would resolve the situation when leakage from other locations obscures the visual examination of the reactor vessel nozzle welds and other RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

Request:

a) Describe the applicant's corrective action that was taken to prevent the refueling cavity seal leakage and to correct the conditions (e.g., corrosion product build-up) that would potentially interfere with the visual examination of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument penetrations

b) If existent, describe any other previous or current leakage that may interfere with the visual examination of the dissimilar metal welds on the reactor vessel nozzles, the bottom-mounted instrument penetrations or the other components included in the scope of the program (LRA Section B2.1.5).

c) Describe how the applicant's implementing procedures would resolve the situation when leakage from the other locations interferes with the visual examination of the RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

## Callaway Response

a) The Callaway Corrective Action Program (CAP) is used to address reactor cavity seal ring leakage that could potentially interfere with the visual examination of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument penetrations. Table 1- RAI B2.1.5-2 – CAP Summary (*Refer to page15 within this enclosure*) provides a summary of CAP items and actions taken over the past 10 years.

The program for examination of the RV Nozzles and bottom head are described below:

<u>Reactor Vessel Loop Nozzles Program</u>:

- An examination is scheduled for cleaning of the reactor vessel loop nozzles at the end of each refueling outage, after the final drain down of the refueling cavity, to ensure any residue due to cavity seal leakage is removed which might interfere with the examination of the nozzles at the beginning of the next refuel.
- An examination is scheduled for the beginning of each refueling outage, except when volumetric examination of the nozzles is to occur, to visually examine the reactor vessel hot leg nozzle dissimilar metal welds.
- An examination is scheduled to be performed every sixth refuel to visually examine the reactor vessel cold leg dissimilar metal welds.

<u>Reactor Vessel Bottom Head Program</u>:

- An examination is scheduled for cleaning of the reactor vessel bottom head and BMI penetrations at the end of each refueling outage, after the final drain down of the refueling cavity, to ensure any residue due to cavity seal leakage is removed which might interfere with the examination of the bottom head and BMI penetrations at the beginning of the next refuel.
- An examination is scheduled of the bottom head and BMI penetrations at the beginning of every other refuel to meet N-722-1 requirements.
- A VT-2 examination is scheduled of the bottom of the reactor vessel and BMI penetrations each refuel that the N-722-1 examination is not performed.

b) No leakage other than the previously discussed Cavity Seal leakage has occurred that may impact the M11B inspections. The M11B dissimilar metal welds on the reactor vessel are examined and cleaned as necessary at the end of each refueling outage so as to remove any residue from refueling operations which could interfere with the examination for leakage at the beginning of the next refueling outage.

c) Callaway procedures covering Visual Examination to ASME VT-2 require the following actions: (N-770-1 and N-722-1 require Visual Examination (VE) of Alloy 600/82/182 components. The VE exam is similar to the VT-2 but with additional requirements.)

- Performance of Visual Examination (VE) on specific Inconel (Alloy 600/82/182 and 690/52/152) components and welds in accordance with implementing work documents.
- Visual Examination (VE) is conducted on the bare surface of the area of interest. This may be accomplished by either removing insulation or by placing a remote visual examination system under the insulation.

- The entire surface of the area of interest is examined. The invoking work document specifies the area of interest. Debris or other restrictions to the examination are to be removed or resolved.

Callaway procedures for boric acid walk down for RCS pressure boundary require the following actions:

- If boric acid residues are detected on or in the vicinity of components, generate a corrective action document and have leakage evaluated, in accordance with the Boric Acid Corrosion Control Program.
- If boric acid deposits are discovered on the surface of the RPV Head or related insulation, regardless of the source or manner found, then an examination is performed of the affected area(s) to verify the integrity of the RPV Head and penetrations prior to returning the plant to operation.

Callaway procedures for RPV Head Bare Metal Examination require the following actions:

- When a condition of degradation (boron, discoloration, corrosion, etc…) is found and cleaning is necessary for evaluation, prior to cleaning:
    - Contact a Radiation Protection (RP) technician and the ISI program owner for cleaning method and cleaning material approval.
    - Ensure care is taken to prevent scouring or removing surfaces metal.

The M11B components are examined and cleaned as necessary at the end of each outage so that any on-line leakage can be identified at the beginning of the next refueling outage. Other than the potential leakage from the M11B locations, there are no potential leakage sources which would interfere with the M11B locations.

## Corresponding Amendment Changes

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

**Table 1 – RAI B2.1.5-2 – CAP Summary**

| CAR Action | Timeframe | Issue | Action |
|---|---|---|---|
| 200207771 | RF 12 | Boric acid residue in incore tunnel and thimble guide tubes from cavity seal leaks. | Indications determined not to be from on-line leakage but from old cavity seal leakage. Cavity seal leakage was not occurring at the time of discovery and had not occurred since RF7. |
| 200403062 | RF 13 | Seal ring hatch leakage. | Hatches inspected and no cause was identified. Issue entered into the Headcrew Operating Experience Log. |
| 200509484<br>200507903 | RF 14 | Cavity seal leakage | Evaluated that seal leakage is not a corrosion concern for the RV.<br><br>Replaced o-rings on hatch bolts. Purchased new segmented seal for RF15. Added seal inspection guidance to the routine maintenance performed on the seal prior to use. |
| 200704522 | RF 15 | No leakage.<br><br>Boron noted on support under reactor vessel support for the D hot leg but not in sufficient quantity to hinder the support examination. | Replaced seal at the beginning of the outage.<br><br>Nozzles were cleaned and performed as-left exam of loop nozzle dissimilar Metals |
| 200811413 | RF 16 | Cavity seal leakage in the area of the "D" hot leg. Boron originated from overhead (above the insulation), was thin and sheet like, and resembled cavity seal leakage. | Cleaned nozzles at end of outage and verified all loop nozzle dissimilar metals were free of boron. |
| 200903264 | Pre-RF 17 | Pre-outage preparation CAR - Cavity seal leakage continues to impact outages | Hatch latching sequence revised to give a more even compression of the hatch seals.<br><br>Replaced a damaged segment of the segmented seal during pre-outage examination and maintenance. |
| 200905026 | RF 17 | No leakage during outage.<br><br>NRC questioned Plant awareness of boron noted on Radiation Protection survey maps of the reactor vessel nozzles | Demonstrated awareness of boron in the area. Verified that the boron was not interfering with dissimilar metal weld examination. |
| 201109516 | RF 18 | Cavity Seal Leakage | Boron residue was removed from the loop nozzle dissimilar metal welds and was removed from the BMI penetrations at the end of RF18.<br><br>Scheduled spray washing of the bottom of the vessel for RF19.<br><br>Planned replacement of the cavity segmented seal prior to RF 19. |

## RAI B2.1.5-3

Background:

The applicant's program evaluation report describes the program elements of Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5). The "parameters monitored/inspected" program element described in the evaluation report indicates that RCPB cracking and leakage are monitored by the applicant's ISI program as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

ASME Code Case N-770-1 specifies volumetric and visual examinations of Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds. Specifically, Inspection Items of ASME Code Case N-770-1, A-1 and A-2 specify the examinations for unmitigated butt welds at hot leg operating temperatures greater than 625 °F (329 °C) and equal or less than 625 °F (329 °C), respectively.

During the audit, the staff noted that applicant's operating experience indicates that the reactor coolant system has experienced reactor hot leg temperature fluctuations associated with periodic, opposing step changes in adjacent hot leg temperatures. This phenomenon has been referred to by the term "upper plenum anomaly" (UPA) and apparently is caused by a flow switching phenomenon in the reactor vessel upper plenum.

Issue:

The UPA may increase the local temperatures of the reactor hot-leg nozzles above 625 °F (329 °C) due to non-symmetrical flow mixing such that Inspection Item A-1, rather than A-2, should be applied to the inspections of the applicant's reactor hot leg nozzles. It is not clear to the staff how the applicant's program evaluates the potential effects of the UPA on the reactor hot leg nozzle temperatures and the determination of the inspection items (i.e., Inspection Items A-1 and A-2).

Request:

a) Provide additional information to confirm that the applicant's program uses relevant inspection items in accordance with ASME Code Case N-770-1: (a) Inspection Item assigned to unmitigated hot leg nozzle butt welds (Inspection Item A-1 or A-2), and (b) the maximum and minimum temperatures of the hot leg nozzles based on adequate consideration of the local temperature distributions and fluctuations at the hot leg nozzles.

   As part of the response, describe how the maximum and minimum hot-leg nozzle temperatures are determined (e.g., an engineering evaluation or actual measurements).

b) If the applicant's Inspection Item for the unmitigated hot-leg nozzle welds is A-2 and the maximum temperature of the hot leg nozzles exceeds 625 °F, clarify why the applicant's program does not specify Inspection Item A-1 to the unmitigated hot leg nozzle welds exposed to temperatures exceeding 625 °F.

c) Describe the operating experience in terms of occurrence of primary water stress-corrosion cracking (PWSCC) in the hot leg nozzles to confirm whether the UPA has an adverse effect on PWSCC of the hot leg nozzles.

## Callaway Response

a) Callaway procedure EDP-ZZ-04070 Appendix A, “Alloy 600 Management Plan” gives detailed guidance for the categorization of the nozzle weld inspections in Section 7.1.4.d, which covers industry requirements and guidance on RPV Inlet and Outlet Nozzle welds.

At Callaway, the upper plenum anomaly (UPA) manifests itself in pairs of loops. In the loop 2 and loop 3 hot legs, loop 2 has a higher temperature than loop 3. When the UPA occurs, the temperature in loop 2 temporarily decreases, accompanied by a corresponding increase in loop 3 temperature. After a few seconds, the temperatures return to normal. When the temperature in loop 3 increases, it does not increase above the temperature in loop 2 prior to the onset of the UPA event. Loops 1 and 4 behave in a similar fashion, with the temperature in loop 1 normally higher than the temperature in loop 4. Thus, the UPA does not affect the maximum temperature of the reactor hot leg nozzles.

Each hot leg has three RTDs installed 120° apart. Computer logs of all the RTDs were reviewed back to 2005, when the steam generators were replaced. During that time period, no RTD indicated a temperature greater than 620°F, except during calibration of an RTD. Based on this review, ASME Code Case N-770-1 inspection item A-2 is assigned.

b) This part is not applicable based on the answer to part a.

c) No cracks have been found in the reactor coolant system hot leg nozzles.

## Corresponding Amendment Changes

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

## RAI B2.1.5-4

Background:

LRA Section B2.1.5 addresses the applicant's Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program. LRA Section B2.1.5 also addresses the operating experience regarding the RPV lower head cladding as follows:

> An indication was visually detected in the RPV lower head cladding in 2007, during the remote VT-3 examination of the vessel interior. The indication was evaluated and additional volumetric and surface examinations were performed for better characterization. The indication was determined to be acceptable as is.

Issue:

During the audit, the staff noted that the applicant's RPV bottom head region has at least two indications of cladding degradation (detected in RFOs 13 and 15 respectively), as indicated in LRA Section 4.7.3. Therefore, the staff needs to clarify how many total indications of RPV cladding degradation have been detected. In addition, the staff noted that the LRA does not clearly provide the following information: (a) the root cause analysis and corrective action for the cladding indications, (b) the previous inspection results to identify any change in the size and depth of the cladding indications, and (c) the inspection method and frequency to manage the degradation of the cladding and RPV, and the technical basis for the adequacy of the inspection method and frequency.

Request:

a) Confirm how many total indications of RPV cladding degradation have been detected. In addition, describe the results of the root cause analysis for the cladding degradation (i.e., what caused the cladding degradation) to confirm whether active degradation of the cladding continues to progress.

b) Describe any corrective action taken to prevent additional cladding and vessel degradation. In addition, describe why the corrective action was adequate to manage the degradation of cladding and reactor vessel.

c) Provide the following information regarding the previous inspection results for each of the cladding indications:

   i. Clarify whether any of these cladding indications is associated with cracking, leakage or other degradation of RPV bottom head penetrations.

   ii. Describe the results (size and depth data) of the previous inspections performed after the initial detections of cladding indications. As part of the response, identify any change in the size and depth of the cladding indications in comparison to the initial size and depth that were detected for the first time.

   iii. Compare the most recent depth data with the thickness of the non-degraded cladding and the thickness of the non-degraded reactor vessel steel (excluding the cladding), respectively.

d) Describe the inspection method and frequency of the subsequent inspections of the cladding indications as defined in the applicant's program. In addition, describe the technical basis for why the inspection method and frequency are adequate to manage the degradation of cladding and RPV.

## Callaway Response

a. The only indications are the two indications that were previously documented during refueling outage 13 (RF13) and refueling outage 15 (RF15). Both indications were determined to be the result of damage during fabrication/construction. The following corrective action document excerpts discuss the discovery and analysis of the RF13 and RF15 indications:

RF13 –"Small rust colored rub mark found on lower reactor vessel".

During Refuel 13 while performing Bottom Mounted Instrumentation (BMI) inspections inside the reactor pressure vessel, a small rust colored mark was identified on the lower reactor vessel wall. A root cause analysis for this issue was performed using a fault tree analysis. The direct cause for the indication on the cladding is excessive grinding or buffing of the cladding resulting in exposure of the low alloy carbon steel base metal, which was caused by: 1) grinding during repair activities; 2) grinding during the completion of the cladding application in the lower dome-to-torus weld; and/or 3) buffing or smoothing performed on-site following vessel installation. No corrective actions are proposed. An engineering evaluation provides documentation that the defect is acceptable "as is" and does not require remediation.

RF15 - "Indication visually detected in the reactor vessel lower head cladding".

The cause of the indication is most likely grinding or similar activities during vessel construction. Stainless steel is highly resistant to erosion and other areas of the vessel seeing higher flow rates do not show similar indications. There is no metal-to-metal contact in this area of the vessel so rubbing is not the cause. There are grinding or flapper wheel marks around the indication which suggest these indications are from fabrication.

b. No additional corrective actions were taken because the indications were found to be due to fabrication/construction issues. The closure statement from the RF15 corrective action document noted the following:

The cladding indication identified at reactor vessel 185 degrees is acceptable as is and does not need to be repaired. This indication is similar to the indication at reactor vessel 303 degrees identified in RF13 and both appear to be from the same cause; a grinding evolution during construction. The cladding surrounding the indication is tightly adhering so does not extend beyond what is visible, and examination of the 303 degree indication found the indication to not be growing which means the indication at 185 degrees should not grow to any extent either.

c.i. Neither indication is associated with cracking, leaking, or other degradation of RPV bottom head penetrations.

c.ii. No further inspections have been done to the cladding indications as of refueling outage 18 (RF18) in 2011. The indications were planned to be inspected during RF18, but difficulties removing the lower internals prevented the inspections from taking place.

c.iii. The most recent depth data is from RF15 which was included in revision 1 to a calculation that evaluated the reactor vessel cladding indication inside the bottom head during RF13. Excerpts from the calculation read as follows:

Design Input 2 - Plant drawings E-11173-171-004 and E-11173-171-005 provide reactor vessel nominal dimensional data as follows:

- Inside radius of reactor vessel shell is 88.16"
- Vessel wall thickness is 5.38" (assume 0.22" clad included)

Design Input 9 - The degraded cladding area dimensions are 1.5" long x 0.625" high x 0.28" deep and 0.53" long x 0.3" high x 0.10" deep, per the UT reports from Wesdyne. While the reports indicate a maximum defect depth of 0.14" from the inner surface, we will assume the low-alloy base metal depth is reduced by 0.14" in addition to the cladding thickness. Thus, 0.28" defect depth is conservative for both indications.

d. The indications are inspected opportunistically when the core barrel is pulled during a refueling outage such as for ASME category B-N-3 examinations. The prior RF13 and RF15 evaluations of the indications determined that there is no growth expected. Based on these evaluations, the opportunistic inspections will be used to manage the degradation of the cladding and reactor pressure vessel.

## Corresponding Amendment Changes

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

## RAI B2.1.6-1

Background:

Table 4-3 of Electric Power Research Institute (EPRI) Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor [(PWR)] Internals Inspection and Evaluation Guidelines (MRP-227-A)," identifies the flexures in the thermal shield assembly as "Primary Inspection Category" reactor vessel internals (RVI) components for Westinghouse plants that will be implementing the MRP-227-A recommendations. During its audit, the staff noted that the program basis documents state that the design of the RVI does not include thermal shield flexures. Instead, the basis documents state that the RVI design includes neutron shield panels in lieu of thermal shield flexures. The applicant stated the neutron shield panels and bolting have been screened out as Category A, "no additional measures" components.

In contrast, Table 4.3-5 in LRA Section 4.3.3 identifies the applicant performed a fatigue analysis on the thermal shield flexures with a calculated cumulative usage factor (CUF) value of 0.978.

Issue:

The information in the basis documents for the applicant's program is in conflict with the information in LRA Section 4.3.3 with respect to the existence of thermal shield flexures. Thus, it is not clear to the staff if the applicant's RVI design includes thermal shield flexures. The applicant has not indicated which alternative RVI components would serve the same intended function as that for the flexures and whether the alternative components serving the same function would need to be inspected. The applicant has also not explained whether the neutron shield will provide the same intended function as the thermal shield.

Request:

Clarify whether the RVI design includes thermal shield flexures. Specifically:

a) If the design includes thermal shield flexures, justify why the PWR Vessel Internals Program would not implement inspections of the flexures consistent with the MRP-227-A recommendations.

b) If the design does not include thermal shield flexures, identify the RVI components that serve the same intended function as thermal shield flexures do for the generic Westinghouse design in MRP-227-A. Justify why the alternative components would not need to be inspected in accordance with MRP-227-A.

## Callaway Response

(a) and (b): As described in Callaway FSAR-SP, Section 3.9(N).5 and Figure 3.9(N)-8, the neutron shield panel assembly consists of four panels that are bolted and pinned to the outside of the core barrel. The thermal shield and thermal shield flexure as described in MRP-227-A, Figure 4-29 and Table 4-3, are not applicable to Callaway.

With the increase in water volume, relative to earlier reactor designs, the effects of gamma heating on the pressure vessel and biological shield have been reduced so as to no longer require the additional steel of a cylindrical thermal shield. Peak values of high neutron flux are also very localized thus limiting the amount of shielding to only those areas where shielding is required. Neutron shield panels are attached to the outside of the core barrel at strategically located positions to reduce the fluence on the reactor vessel welds. The thermal shield design provides shielding for the complete 360-degree circumferential sectors. The neutron panel design (set of stiff plates) does not employ a complete cylinder (flexible shell) but instead uses cylindrical segments whose azimuthal extent is limited to regions of high neutron flux. Due to size difference, using neutron shield panels also results in a significant reduction in weight relative to the thermal shield design.

The neutron shield panels and bolting have been screened out as Category A in the MRP-191, Table 7-2. As defined in MRP-191, Section 2.0, only the required ASME Section XI, Category B-N-3 ISI visual examinations will be performed on these components.

LRA Table 4.3-5 has been revised, as shown on Amendment 7 in Enclosure 2 to clarify the CUF value of 0.978 is provided for neutron panel bolts instead of the thermal shield flexure.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 7, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

## RAI B2.1.6-2

Background:

Table 4-9 in EPRI Report No. 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)” identifies the upper support ring or skirt in the upper internal assembly of Westinghouse reactor designs as “Existing Program Category” RVI components for Westinghouse plants implementing the MRP-227-A recommendations.

Issue:

During the audit, the staff noted that the applicant’s program basis documents do not identify that scope of the AMP includes inspections of an upper support ring or skirt in upper internals assembly of the facility. It is not clear to the staff if the RVI design includes an upper support ring or skirt. The applicant has not indicated which alternative RVI components would serve the same intended function as that for the upper support ring or skirt and whether the alternative components serving the same function would need to be inspected.

Request:

Clarify whether the RVI design includes an upper support ring or skirt.

a) If the design includes an upper support ring or skirt, justify why the PWR Vessel Internals Program would not implement inspections of the component consistent with the MRP-227-A recommendations.

b) If the design does not include an upper support ring or skirt, identify the RVI components that serve the same intended function as the upper support ring or skirt do for the generic Westinghouse design in MRP-227-A. Justify why the alternative components would not need to be inspected in accordance with MRP-227-A.

## Callaway Response

a) and b) Review of the detailed screening evaluation of MRP-227-A found in MRP-191 indicates the Upper Support Skirt is a subcomponent of the Upper Support Plate. Callaway FSAR Figure 3.9(N)-3 confirms that the component between test inspection points #12 and #13 is the Upper Support Skirt.

LRA Section 2.3.1.1, Table 2.3.1-1 and Table 3.1.2-1 have been revised, as shown on LRA Amendment 7 in Enclosure 2, to add Upper Support Skirt as an “Existing Program Category” component consistent with the MRP-227-A recommendations to the PWR Vessel Internals Program.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 7, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

## RAI B2.1.6-3

Background:

Section 4.4.3 and Table 4-9 in MRP-227-A list those existing program components that are identified as ASME Code Section XI core support structure components. MRP-227-A states that these components are examined per ASME Code Section XI Table IWB-2510, "Examination Category B-N-3 requirements."

Issue:

During the audit, the staff noted that the applicant's program basis documents do not identify which RVI components are ASME Code Section XI, Examination Category B-N-3 components. The applicant also has not explained whether the method of performing the VT-3 visual examination in accordance with this examination category would actually achieve coverage of those RVI components that were designated as ASME Code Section XI Examination Category B-N-3 components in the MRP-227-A report. The applicant has not explained if there are any additional RVI components that are ASME Code Section XI, Examination Category B-N-3 components, but not assumed in Table 4.9 of the generic MRP-227-A methodology.

Request:

a) Identify all RVI component locations that are designated as ASME Code Section XI, Examination Category B-N-3 components.

b) Identify any B-N-3 component locations and associated aging effects that are not assumed in Table 4.9 of the generic MRP-227-A methodology.

c) Based on previous ASME Section XI examinations of B-N-3 component surfaces, clarify and justify whether the implementation of VT-3 examinations of these surfaces will actually achieve coverage of those B-N-3 components locations that are identified in the MRP-227-A report and included in the RVI design.

## Callaway Response

MRP-227-A guidance for selecting RVI components is based on a four-step ranking process. Through this process, the reactor internals are assigned to one of the following four groups: Primary, Expansion, Existing Programs, and No Additional Measures components. The degradation effects in a third set of Existing Program components are deemed to be adequately managed by the ASME Code, Section XI, Examination Category B-N-3 examinations of core support structures. MRP-227-A states that these components are examined per ASME Code Section XI Table IWB-2500-1, "Examination Category B-N-3 requirements." MRP-227-A also states that for those components in the No Additional Measures group, the Examination Category B-N-3 requirements must continue to be met unless specific relief is granted as allowed by 10 CFR 50.55a.

a) Consistent with Table 4-9 of MRP-227-A, Callaway PWR Vessel Internals program identifies the Callaway RVI Existing Program components that are ASME Code Section XI, Examination Category B-N-3 components with the examination method of VT-3.

   As indicated in MRP-227-A, Section 3.3.1, the categorization and analysis processes for the four-step ranking are not intended to supersede any ASME Code Section XI requirements. Any components that are classified as core support structures as defined in IWB-2500 and listed in Table IWB 2500-1, Category B-N-3, have requirements that remain in effect.

Therefore, the RVI components listed in LRA Table 2.3.1-1 except " RVI Neutron Shield Panel" and "RVI BMI Flux Thimble", though categorized per MRP-227-A to four ranking groups, are all designated as ASME Code Section XI, Examination Category B-N-3 components. The augmented inspections for the Primary group and Expansion group are addressed in Callaway program basis documents, Element 4, consistent with Table 4-3 and Table 4-6 of MRP-227-A, respectively.

b) The acceptance standard of ASME Code IWB-3520.2 for Examination Category B-N-3 identifies the aging effects of cracked parts, general corrosion and wear that VT-3 is credited for detecting. Since general corrosion is not a concern for the materials used for PWR vessel internals, the only applicable aging effects that VT-3 could be used for are cracking and wear in PWR vessel internals. This is consistent with the aging effects assumed in Table 4-9 of MRP-227-A.

c) All of the core support structures governed by B-N-3 require a VT-3 examination as defined in Table IWB 2500-1. A VT-3 examination looks at the loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion as described in IWB-3520.2. As indicated in MRP-227-A, the VT-3 examination of Category B-N-3 are considered sufficient to monitor the aging effects addressed in Table 4-9 of MRP-227-A for the Existing Program components.

## Corresponding Amendment Changes

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

## RAI B2.1.7-1

Background:

SRP-LR, Section A.1.2.3.1, states that the scope of program should include the specific components that are being age managed by the program. LRA Section B2.1.7, "Flow-Accelerated Corrosion," states that analyses to determine critical locations in piping and other components susceptible to flow-accelerated corrosion (FAC) are performed using CHECWORKS™. The CSI Technologies, "Callaway FAC System Susceptibility Evaluation Report," states that the purpose of this evaluation is to define the scope of the Flow-Accelerated Corrosion program. Appendix A of Callaway FAC System Susceptibility Evaluation Report states that the chemical and volume control system (designated as BG) is excluded from the Flow-Accelerated Corrosion program based on non-susceptible materials. However, LRA Table 3.3.2-10, "Auxiliary Systems - Summary of Aging Management Evaluation - Chemical and Volume Control System," includes an item for carbon steel piping that is being managed for wall thinning by the Flow-Accelerated Corrosion program.

Issue:

It is not clear to the staff whether the LRA is crediting the Flow-Accelerated Corrosion program for managing portions of a system that has been excluded from the Flow-Accelerated Corrosion program based on non-susceptible material, or whether the system has susceptible material that was not evaluated in the Callaway FAC System Susceptibility Evaluation Report.

Request:

For the component(s) addressed by the AMR item in LRA Table 3.3.2-10, which are being managed for wall thinning by the Flow-Accelerated Corrosion program, clarify whether the LRA is crediting the Flow-Accelerated Corrosion program for managing portions of systems that have been excluded from the program through the "Callaway FAC System Susceptibility Evaluation Report," or whether the system has components with susceptible material that were not evaluated in the above report. Depending on the determination, include additional information to ensure that other components in other tables do not have similar issues.

## Callaway Response

The carbon steel piping managed by the Flow-Accelerated Corrosion (FAC) program in LRA Table 3.3.2-10, Chemical and Volume Control system, is the auxiliary steam supply to the boric acid batching tank. Although this line has a component designator which indicates that it is part of the Chemical and Volume Control system, the Callaway FAC System Susceptibility Evaluation included it with the upstream Auxiliary Steam system line which supplies steam to the boric acid batching tank. These lines were excluded from the FAC program because they operate less than two percent of the time, not because their material is not susceptible to FAC.

The carbon steel piping in the Chemical and Volume Control system was incorrectly shown in LRA Table 3.3.2-10 as being managed by the FAC program. LRA Table 3.3.2-10 has been revised, as shown on Amendment 7 in Enclosure 2 to delete this line. In addition, the aging effect of wall thinning and the aging management program of Flow-Accelerated Corrosion have been removed from LRA Section 3.3.2.1.10, as shown on Amendment 7 in Enclosure 2.

A review was conducted to determine if there were other similar errors in the LRA. Only one additional occurrence was found. The component type silencer in the Main Steam system in LRA Table 3.4.2-2 is not managed by the FAC program because it operates less than two percent of the time. LRA Table 3.4.2-2 has been revised, as shown on Amendment 7 in Enclosure 2 to delete this line.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 7, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

## RAI B2.1.7-2

Background:

GALL Report AMP XI.M17, “Flow-Accelerated Corrosion,” “detection of aging effects,” program element states that ultrasonic or radiographic testing is used to detect wall thinning. LRA Section B2.1.7, Program Description, states that the program uses baseline and follow-up inspections, and the inspections are performed “using ultrasonic, visual or other approved testing techniques capable of detecting wall thinning.”

Issue:

The GALL Report AMP does not discuss visual inspections as a method to detect wall thinning. Neither the Callaway AMP Evaluation Report nor the implementing procedures for the Flow-Accelerated Corrosion program describe the use of visual inspections. It is not clear to the staff whether visual inspections will be used in lieu of ultrasonic testing, or other approved testing technique, to detect wall thinning or in what specific circumstances visual inspections will be used in the Flow-Accelerated Corrosion program.

Request:

Provide information to clarify how visual inspections are used to detect wall thinning due to FAC. If visual inspections are used in lieu of volumetric non-destructive examination techniques, provide the bases for verifying that minimum wall thickness criteria will be met and calculating the remaining service life of a component. Depending on resolution, clarify the summary description of the program in LRA Appendix A, Final Safety Analysis Report supplement.

## Callaway Response

As discussed in NSAC-202L-R3, visual observations may be used for very large diameter piping, followed by UT examinations of areas where significant damage is observed or suspected. Visual examinations may also be performed for valves and other components which are not suitable for UT examination due to their shape or thickness. Visual examinations provide qualitative indications of FAC, and are not used to determine wall thickness.

## Corresponding Amendment Changes

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

## RAI B2.1.7-3

Background:

GALL Report AMP XI.M17, “acceptance criteria” program element states that inspection results are input for a predictive code to calculate the number of operating cycles remaining before the component reaches the minimum allowable wall thickness. Industry guidance, Nuclear Safety Analysis Center (NSAC) 202L, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” states that a minimum safety factor should never be less than 1.1, to account for wear rate inaccuracies when calculating the remaining service life of a component. The Flow-Accelerated Corrosion program implementing procedure, EDZ-01115, specifies a safety factor of 1.1 in calculating an “Inspection Index” for some situations. LRA Section B2.1.7, Program Description, states that “FAC Manager Web Edition,” is utilized to calculate component wear, wear rate and the next scheduled inspection.

Issue:

It is not clear to the staff whether the Flow-Accelerated Corrosion program implementing procedure requires a safety factor of 1.1 when calculating the remaining service life of a component. Although specified in calculating an “Inspection Index” it does not appear that this value is currently being used to determine a component’s next scheduled inspection. In addition, it is not clear whether “FAC Manager Web Edition,” uses a safety factor of 1.1 in calculating wears rates and next scheduled inspections.

Request:

Confirm that calculations to determine the remaining service life or the next scheduled inspection of a component use a safety factor of 1.1 and provide information showing how this aspect is controlled through the implementing procedure(s). Alternatively, provide the bases for why the safety factor recommended by industry guidance is not being used, and how calculations for remaining service life and next scheduled inspections account for potential wear rate inaccuracies.

## Callaway Response

FAC Manager Web Edition uses a safety factor which is defined by the user. Callaway has set it to 1.1. A corrective action request has been initiated to revise Callaway procedure EDP-ZZ-01115, Flow-Accelerated Corrosion of Piping and Components Predictive Performance Manual, to clarify that a safety factor of no less than 1.1 is to be used in calculations of remaining service life.

## Corresponding Amendment Changes

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

## RAI B2.1.7-4

Background:

SRP-LR Section A.1.2.3.10, "Operating Experience," states that the operating experience of existing programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. GALL Report AMP XI.M17, "program description," states that the program relies on implementation of the guidelines in the NSAC-202L. That guidance document states that it addresses wall thinning caused by FAC, and that it does not cover other thinning mechanisms, such as cavitation, and erosive wear.

The Callaway Plant Aging Management Callaway Action Request (CAR) Operating Experience Report for this program cites "loss of material due to erosion" as an aging effect addressed by this program in its discussion for CAR 200608992. The Operating Experience Report also discussed CAR 200102270, which listed the corrective actions to prevent recurrence for wall thinning in main feedwater components, and stated, " ... expanded the scope of wall thinning inspections to include other potential damage mechanisms (impingement, cavitation, etc.)." In addition, the Operating Experience Report included CAR 201004190, which addressed a valve with internal erosion and "adjacent pipe wall erosion," and stated that the CAR is addressed by the Flow-Accelerated Corrosion program.

Issue:

Based on the Operating Experience Report provided for this program, it was not clear to the staff whether mechanisms other than FAC are being managed by this program. In addition, based on past corrective actions, the scope of wall thinning inspections may include impingement and cavitation aging mechanism.

Request:

Discuss whether aging mechanisms other than FAC are being managed through the Flow-Accelerated Corrosion program. If applicable, provide information regarding this enhancement to the program. Since aging mechanisms such as erosion due to cavitation, droplet impingement, or flashing have been identified in operating experience documents at Callaway, if the resulting loss of material is not being managed by the Flow-Accelerated Corrosion program, provide the AMP(s) where this aging effect is being managed and provide details on how the aging effect due to these mechanisms is being managed.

## Callaway Response

The Callaway Flow-Accelerated Corrosion (FAC) program does not manage aging mechanisms other than FAC for piping components within the scope of license renewal.

A review of Callaway corrective action documents indicates that wall thinning due to mechanisms other than FAC in components within the scope of license renewal is rare. None of the CARs cited in this RAI identified wall thinning due to mechanisms other than FAC in components within the scope of license renewal.

When wall thinning due to a mechanism other than FAC is discovered, it is addressed by the corrective action program. Possible corrective actions include fixing the cause of the wall thinning, or, if this is not practical, using an existing program such as the open-cycle cooling water program to monitor the component.

CAR 201004190, mentioned in the RAI text, provides an example where the cause of the wall thinning was corrected. In this case, erosion of the valve seat caused the upstream valve to leak by causing erosion of the downstream components. The corrective action included replacing the valve which experienced the damage due to erosion, and replacing the upstream valve with the seat leakage. The two valves and associated piping are in a portion of the feedwater system that is not within the scope of license renewal.

CAR 200102270, mentioned in the RAI text, was written to document FAC which exceeded predictions. Subsequent investigation resulted in revising the FAC models. Part of the extent-of-condition review was to evaluate the possibility of wall thinning due to other mechanisms, such as impingement and cavitation. This action was closed to the equipment reliability improvement program (ERIP), in which engineers are responsible for identifying health issues in their assigned systems. No wall thinning due to mechanisms other than FAC, such as impingement and cavitation, were identified by ERIP for components within the scope of license renewal.

CAR 200608992, mentioned in the RAI text, identified a leak in an elbow of the service water piping downstream of the ‘B’ stator cooling water heat exchanger due to erosion. A temporary repair was made, and the elbow was subsequently replaced. This component is not within the scope of license renewal.

An example of a component within the scope of license renewal experiencing erosion may be found in CAR 200703776, which is included in the Operating Experience Report. This CAR addresses erosion/corrosion found on the discharge piping of the ‘B’ essential service water (ESW) pump. This section of pipe was replaced, and is scheduled to be re-inspected in Refuel 19 (spring, 2013). Piping in the ESW system is monitored by the Open-Cycle Cooling Water program.

## Corresponding Amendment Changes

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

## RAI B2.1.7-5

Background:

GALL Report AMP XI.M17, "acceptance criteria," program element states that if calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, corrective action should be considered.

The Callaway Operating Experience Report included CAR 20043322, which addresses the findings from FAC inspections during RFO 13. For component AE05-AB590, the CAR states that "this calculation decreased the design minimum thickness required by utilizing the measured ultimate tensile strength listed in the Certified Materials Test Report [(CMTR)]." In justifying the use of CMTR data, Callaway personnel provided Engineering Design Guide, ME 013, "Pipewall Thickness," which stated that "the use of CMTR data [in] lieu of using the published allowable stress for the material is permissible to further refine the minimum wall thickness analyses." The Design Guide also stated that, as it is defined, the minimum wall thickness is the thickness that will meet the applicable code requirements for a given application and that the process described can also be applied to piping designed to American National Standards Institute (ANSI) B31.1.

Issue:

It is the staff's understanding that the minimum wall thickness calculated for ASME Class 2 and Class 3 and ANSI B31.1 applications requires the use of published allowable stress values and does not include consideration of CMTR data. It is not clear to the staff whether Callaway's minimum wall thickness calculations allow the use of CMTR data to reduce the minimum wall thickness in determining continued operation, or scheduling the next inspection of a component.

Request:

Provide information regarding the use of CMTR data to reduce the minimum wall thickness calculated for ASME Class 2 and Class 3 and ANSI B31.1 applications, as documented in Design Guide ME 013, "Pipewall Thickness." If this approach will be used during the period of extended operation, demonstrate through NRC-approved code cases, or other documentation, that this approach meets the applicable code(s) of construction and the CLB for Callaway.

## Callaway Response

As noted in the RAI, Callaway's Engineering Design Guide, ME 013, "Pipewall Thickness," states that "the use of CMTR data [in] lieu of using the published allowable stress for the material is permissible to further refine the minimum wall thickness analyses." The Design Guide also states that, as it is defined, the minimum wall thickness is the thickness that will meet the applicable code requirements for a given application and that the process described can also be applied to piping design to American National Standards Institute (ANSI) B31.1.

The Staff asserts that the minimum wall thickness calculated for ASME Class 2 and Class applications requires the use of published allowable stress values and does not include consideration of CMTR data. Note that the allowable stress limits of ASME are based upon the ASME required margin of safety above minimum required material strengths; the bases for determination of allowable stress limits are further defined in ASME Section III, Appendix III, Article 3000. These bases would also be applied for situations when acceptance criteria must be established for a material that is not listed in the stress tables. CMTR data can be applied when the documented material strength is greater than the minimum required strength for that particular standard. The margins of Article 3000 are applied to preserve the margin of safety established by ASME. Hence, use of CMTR data does not result in any reduction of conservatism.

This methodology was also evaluated in "Specification for Evaluation and Acceptance of Local Areas of Material, Parts and Components that are Less Than The Specified Thickness," prepared for Union Electric by Reedy Associates, 1993. In this report, Section 7.0, "Allowable Stress," states:

For items which have been placed in service, engineering evaluations performed either because of a condition of reduced thickness, or unanticipated loads, are beyond the scope of (ASME) Section III. As discussed in Section 7.0 of Part I, such evaluations should be based on engineering judgment. Depending on the amount of conservatism desired, the allowable stresses may be:

a. Code allowable stresses,

b. Allowable stresses based on actual properties of the material as recorded in CMTR's,

c. Values up to 90% of yield strength.

Although most engineers try to use Code stress values where possible, recent Code Interpretations point out that this is not a requirement. The values used will be dependent on the engineering judgment of the responsible engineer. When Code values are exceeded, it is recommended that the responsible engineer be a registered professional engineer experienced in the application of the ASME Code.

Although the Engineering Design Guide, ME 013 states that similar processes may be applied to ANSI B31.1 piping, note that use of CMTR data is not directly applicable. Piping purchased to ANSI B31.1 requirements is not typically provided with CMTRs; therefore, CMTR data would not be used to refine minimum wall thickness analyses for B31.1 piping.

## **Corresponding Amendment Changes**

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

## RAI B2.1.7-6

Background:

The GALL Report, “Introduction,” states that if an applicant takes credit for a program in the GALL Report, it is incumbent on the applicant to ensure that the operating experience at the plant is bounded by the operating experience for which the GALL Report was evaluated. The Callaway Operating Experience Report included CAR 200500411, which describes the failure of a flow meter component due to FAC. Based on the discussion, a flow tube separated from its venturi throat, migrated down the pipe, and blocked the minimum recirculation flow line. The spool piece containing the flow venturi had been inspected in 2004 and was projected to last more than 50 years; however, the configuration of the flow element does not allow it to be inspected from the outside of the pipe using ultrasonic testing methods. The staff notes that while the wall thinning due to FAC is not unique, this operating experience is unique because normal wall thinning inspections cannot be used to monitor ongoing wall thinning of a passive component.

Issue:

The failure of the flow element resulted in macrofouling, which is not an aging mechanism that is associated with the Flow-Accelerated Corrosion program. The Flow-Accelerated Corrosion program manages loss of material, which is associated with the “pressure boundary.” As defined in Nuclear Energy Institute (NEI) 95-10, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,” the intended function of “pressure boundary” is to “provide pressure retaining boundary so that sufficient flow at adequate pressure is delivered.” In this case, the pressure retaining boundary was not affected, but the result was insufficient flow, which is a purpose of the pressure boundary intended function. In that regard, the plant-specific operating experience is not bounded by the industry operating experience for which the GALL Report program was evaluated.

Request:

If macrofouling due to flow element failure caused by FAC is no longer applicable to Callaway, provide the bases for why it is not applicable. Otherwise, if this aging mechanism will be managed by the Flow-Accelerated Corrosion program or by another AMP, then provide information to demonstrate how macrofouling due to flow element failure caused by FAC will be managed.

## Callaway Response

The failed flow element discussed in CAR 200500411 is the flow element downstream of the ‘A’ heater drain pump. The internal environment is sub-cooled secondary water at a temperature of over 350°F. It consisted of a stainless steel throat welded to a carbon steel body. The carbon steel body separated from the throat due to FAC.

To prevent recurrence, the flow element was replaced with an all stainless steel design. In addition, the flow elements downstream of the ‘B’ heater drain pump and in the heater drain pump discharge header were also replaced with an all stainless steel design.

To determine the extent of condition, a review was conducted to determine all the locations of flow elements with a stainless steel throat and a carbon steel body. The only other flow elements of this design were in the discharge line of each of the three condensate pumps and in the suction line of each of the two main feedwater pumps.

The flow element at the suction of ‘A’ main feedwater pump was inspected in 2010 and replaced with an all stainless steel design. From the inspection, there were no areas of severe wear, and no cracking was found in the welds. UT inspection indicated there was no wall thinning. The flow element at the suction of ‘B’ main feedwater pump is currently scheduled to be inspected and replaced in 2014.

It is not intended to inspect the flow elements in the discharge lines of the condensate pumps because of the results of the inspection of the flow element at the suction of ‘A’ main feedwater pump and because the water temperature at these flow elements is only 130°F.

The corrective actions taken in response to CAR 200500411 are adequate to prevent failure of flow elements with a stainless steel throat welded to a carbon steel body.

The components discussed in this response are not within the scope of license renewal.

## Corresponding Amendment Changes

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

## RAI B2.1.10-1

Background:

GALL Report AMP XI.M20 states that the program relies on implementation of the recommendations in Generic Letter (GL) 89-13, and the “detection of aging effects” program element states that inspection methods (e.g., visual or nondestructive examination) are in accordance with the applicant’s docketed response to GL 89-13. LRA Section B2.1.10, “Open Cycle Cooling Water System,” states that the activities for this program are consistent with the Callaway commitments to GL 89-13. The applicant’s response to GL 89-13, dated January 29, 1990, states that selected sections of ESW system piping are inspected each RFO for corrosion, erosion, and biofouling. The applicant’s response to GL 89-3 also states that “each pipe is radiographed to determine any localized pitting. This is followed by ultrasonic testing using accurately placed grid locations to determine the extent of any damage.”

Callaway’s AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.4.2, states that selected sections of ESW piping are ultrasonically tested every 18 months for trending of wall thickness measurements. Callaway’s implementing procedure, EDP-ZZ-01121, “Raw Water Systems Predictive Performance Program,” does not discuss radiography as one of the nondestructive examination techniques used to inspect ESW piping.

Issue:

The activities for this program do not appear to be consistent with the Callaway commitments to GL 89-13 regarding nondestructive examination techniques conducted each RFO.

Request:

Provide information demonstrating that the open-cycle cooling water system program is consistent with the Callaway commitments to GL 89-13, regarding nondestructive examination techniques conducted during each RFO. If radiographic examinations are no longer being performed, then provide documentation related to this apparent change to an NRC commitment, and if other inspection methods are being credited in lieu of radiographic examinations, describe how they provide a similar ability to detect degradation.

## Callaway Response

Element 4 of AMP XI.M20 Open-Cycle Cooling Water states inspections, surveillance and testing are done consistent with Callaway’s response to NRC GL 89-13. UE Letter ULNRC-2146 in response to NRC GL 89-13 stated that Callaway will radiograph essential service water piping to detect localized areas of pitting (referred to as scan inspections), then follow up with ultrasonic thickness (UT) measurements to determine the extent of degradation. Technology has evolved such that per EDP-ZZ-01121, Callaway now uses low-frequency electromagnetic technique (LFET) measurements to perform the scan inspections to quickly find areas of pipe that may be degraded. Callaway thus still meets the original intent of doing large scale scan inspections to find areas that may show degradation, which can then be followed up by UT measurements.

Failure to update the original commitment for non-destructive technology improvements has been entered into the Corrective Action Program.

## Corresponding Amendment Changes

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

## RAI B2.1.10-2

Background:

SRP-LR, Section A.1.2.3.4, “Detection of Aging Effects,” states that when sampling is used in condition monitoring programs, applicants should provide the basis for the inspection population and the sample size. Callaway’s response to GL 89-13, dated January 29, 1990, states that selected sections of ESW system piping are inspected each RFO for corrosion, erosion, and biofouling.

Callaway’s AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.4.2, states that wall thickness of selected sections of ESW piping are trended and that locations are determined by the raw water systems engineer. During its review of Callaway’s implementing procedure, EDP-ZZ-01121, “Raw Water Systems Predictive Performance Program,” the staff could not confirm the information describing the number of trended locations, nor the criteria used to identify these locations. In addition, the implementing procedure included Appendix 2, “Non-Trended Monitored Locations for Raw Water Program,” and stated that raw water corrosion engineer updates this list as required, but did not discuss what those requirements were and did not provide the purpose of these non-trended monitored locations

Issue:

Information was not available regarding the number or selection criteria for the locations being trended by the “Raw Water Systems Predictive Performance Program.” Also, the identification criteria and purpose of the non-trended monitored locations listed in Appendix 2 was not provided.

Request:

a) For the selected sections of ESW piping that are inspected each outage for corrosion, erosion and biofouling, provide details regarding the number of locations inspected, the criteria used to select the locations and the inspection method(s) used.

b) For the non-trended monitored locations, provide information regarding the criteria used to select the locations and the purpose for monitoring these non-trended locations.

## Callaway Response

a) For the selected sections of Essential Service Water (ESW) piping that are inspected each outage for corrosion, erosion and biofouling, the criteria used to select the locations include: operating condition (areas with stagnant/intermittent flow), pipe material, piping age, pipe configuration, results of previous inspections, recent/near term challenges with the system/piping, chemistry trend data (MIC sampling), industry operating experience and system engineering recommendations. The number of selected locations varies from outage to outage based on the previously mentioned sample criteria. The inspection methods include Ultrasonic Thickness (UT), Low Frequency Electromagnetic Technique (LFET) and opportunistic visual inspections. LFET is a form of electromagnetic testing and is used specifically for screening large areas of piping quickly. The LFET scanner is moved across the pipe and will detect changes in the wall thickness of the pipe as it moves across the surface. Thinned areas found during the LFET scan are followed up with UT measurements.

b) The non-trended monitored locations are areas where permanent repairs were performed (such as capped nipolets) which are considered for future monitoring.

## Corresponding Amendment Changes

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

## RAI B2.1.10-3

Background:

GALL Report AMP XI.M20, states that the program relies on implementation of the recommendations in GL 89-13, which includes surveillance and control techniques to manage aging effects caused by protective coating failures and other mechanism in the open-cycle cooling water system. The “parameters monitored/inspected” program element states, in part, that components with internal linings or coatings are periodically inspected, and that the program ensures that defective protective coatings that could adversely affect component performance are detected. LRA Section B2.1.10, Program Description, states that Callaway uses internal coatings on the component cooling water heat exchanger end bells, channels, and tubesheets, the control room air conditioner tubesheets, the class 1E electrical equipment air conditioner tubesheets, and the ESW system strainers.

Callaway’s AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.3.2, states that heat exchanger inspections are performed for fouling, sediment, corrosion, erosion, and pitting; however, coating failure is not included. This section also states that heat exchangers and ESW strainers are coated, “but this amount of surface area is relatively small and has not been a concern for [ESW] system performance.” Implementing procedure ETP-ZZ-3001, “GL 89-13 Heat Exchanger Inspections” Section 7.1.11 states to check heat exchanger coatings when they are accessible for inspections, but Callaway’s revised GL 89-13 commitments in letter dated July 16, 2007, states that thermal performance testing will be the primary monitoring method of component cooling water heat exchanger with cleaning and inspections planned as necessary.

Issue:

Callaway has coatings applied to various heat exchanger and the ESW strainers, but it is not clear how the aging effects caused by failure of these coatings are being managed by the Open-Cycle Cooling Water System program. While most heat exchangers will be periodically inspected in lieu of thermal performance testing, which provides an opportunity to inspect for coating degradation, the primary monitoring method for the component cooling water heat exchanger is thermal performance testing, which may not afford an opportunity to detect coating degradation prior to failure.

Request:

a) For heat exchangers with applied coatings, where coating failure could adversely affect the heat exchanger or downstream components, clarify whether periodic inspections procedures will include the detection of coating degradation. Alternatively, provide justification to demonstrate that periodic inspections for coating degradation are not needed.

b) Except for the component cooling water heat exchanger, confirm that the frequency of these inspections will not exceed 5 years (as documented in Callaway’s revised GL 89-13 commitments), or provide justification for an inspection frequency greater than 5 years. For the component cooling water heat exchanger, address the inspection frequency for occasions where periodic thermal performance testing, flow verification or routine monitoring of the heat exchanger differential pressure does not indicate the need for inspection or cleaning for extended periods.

## Callaway Response

a) Callaway uses internal coatings on the following GL 89-13 safety-related heat exchangers:

- Component cooling water heat exchanger end bells, channels, and tubesheets;
- Control room air conditioner tubesheets;
- Class 1E electrical equipment air conditioner tubesheets;
- Essential service water (ESW) system strainers.

The heat exchanger inspection procedure of the Open-Cycle Cooling Water program requires the coatings in all of the GL 89-13 safety-related heat exchangers to be inspected for signs of degradation anytime they are accessible for inspection. The ESW strainers are inspected consistent with PM basis. The Open-Cycle Cooling Water program implementing procedure will be enhanced to specify inspection of the coatings in the essential service water strainers. LRA Appendix B2.1.10 and LRA Table A4-1 item 6 have been revised as shown on Amendment 7 in Enclosure 2 to identify an enhancement for inspection of the ESW strainers for coating degradation.

b) The following internal coating inspection frequencies currently apply to inspection of internal coatings of the following GL 89-13 safety-related heat exchangers:

- Component cooling water heat exchangers:
  at least every five years (one is inspected each refueling outage.)
- Control room air conditioners:
  at least every five years
- Class 1E equipment air conditioner:
  at least every five years
- ESW strainers:
  inspected once every 6 years (this corresponds to an ESW outage which is performed once every 4 refueling outages.)

Since the total amount of internal coating is small and there has been no recent documented operating experience of internal coating failures, the frequency of inspections indicated for the component cooling water heat exchangers, the control room air conditioners, the class 1E heat exchangers, and the ESW strainers will provide reasonable assurance that the ESW system will effectively identify coating failures and aging so that corrective actions can be initiated.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, “Amendment 7, LRA Changes from RAI Responses,” for a description of LRA changes with this response.

## RAI B2.1.10-4

Background:

GALL Report AMP XI.M20 “detection of aging effects” program element states that inspection methods (e.g., visual or nondestructive examination) are in accordance with the applicant’s docketed response to GL 89-13. LRA Section B2.1.10, “Open-Cycle Cooling Water System,” states that the activities for this program are consistent with the Callaway commitments to GL 89-13. Callaway’s response to GL 89-13, dated January 29, 1990, Enclosure 2, Item III.B, states, in part, that air flow rates of all air-to-water heat exchangers are taken and trended and that visual inspections of the air side of the heat exchangers will be performed. Callaway’s letter dated July 16, 2007, which modified its GL 89-13 commitments, appears to address cleaning and inspection of the water side of the tubes for all of the room coolers, but does not discuss air side inspections. For the containment air coolers, the 2007 letter states the primary monitoring method will be cleaning and inspection of the inner tube walls and outer coil fins per EDP-ZZ-01112.

Implementing procedures EDP-ZZ-01112, “Heat Exchanger Predictive Performance Manual,” and ETP-ZZ-03001, “GL89-13 Heat Exchanger Inspection,” do not discuss inspections of the air side of heat exchangers, and do not address the tracking and trending of air ‘flow rates on air to water heat exchangers. The note in EDP-ZZ-01112, Step 4.1.1.g states that EPRI 1007248 was used as additional guidance on non-condensing room coolers to determine the inspection and cleaning methods. EPRI 1007248, “Summary,” states “... an analysis in conjunction with periodic flow and pressure-drop testing and regular air-side inspections and cleanings satisfies the intent of Generic Letter 89-13 ...”

Issue:

The activities for this program do not appear to be consistent with the Callaway commitments to GL 89-13 regarding inspections for the air-side of heat exchangers. In addition, although heat transfer is the intended function listed for heat exchangers exposed to ventilation atmosphere in various LRA Tables, (e.g., 3.3.2-11, 3.3.2-13, 3.3.2-14, 3.3.2-15, and 3.3.2-19), reduction of heat transfer is not listed as an aging effect requiring management for these GL 89-13 components.

Request:

Provide information demonstrating that the open-cycle cooling water system program is consistent with the Callaway commitments to GL 89-13, with respect to air-side inspections and air flow rate trending of heat exchangers. If inspection and trending activities for fouling of the air side of heat exchangers are being performed, then update the appropriate tables in the LRA to reflect these aging management activities for aging effects requiring management of the associated components. However, if visual inspections of the air side of the heat exchangers are no longer being performed, and air flow rates are not being taken and trended, then provide documentation related to this apparent change to an NRC commitment and either describe how reduction of heat transfer due to air-side fouling is being managed or provide the bases for not treating air-side reduction of heat transfer as an aging effect requiring management.

## Callaway Response

The following LRA Chapter 3 AMR Tables have been revised to require management of reduction of heat transfer and loss of material aging effects by the Open-Cycle Cooling Water

System program (B2.1.10) for heat exchanger components that have a heat transfer intended function in a ventilation atmosphere.

Table 3.3.2-11 – Control Building HVAC System

Table 3.3.2-13 – Auxiliary Building HVAC System

Table 3.3.2-14 – Fuel Building HVAC System

Table 3.3.2-15 – Miscellaneous Buildings HVAC System

Table 3.3.2-19 – Containment Cooling

Callaway has regularly cleaned and inspected the air-side of the GL 89-13 safety-related heat exchangers noted in the above LRA Tables that have a heat transfer intended function. However, to demonstrate consistency with Callaway's GL 89-13 commitments, the heat exchanger inspection procedure of the Open-Cycle Cooling Water System program (B2.1.10) will be enhanced to visually inspect and clean if necessary the air sides of the GL 89-13 safety-related heat exchangers that have a heat transfer intended function. An enhancement has been added to Appendix B Section B2.1.10 to reflect the commitment to revise this procedure.

Consistent with Callaway's revised commitments to GL 89-13 documented in ULNRC-05425, air-flow testing is no longer required for the safety-related air-to-water heat exchangers.

LRA Tables 3.3.2-11, Table 3.3.2-13, Table 3.3.2-14, Table 3.3.2-15, and Table 3.3.2-19, have been revised as shown on LRA Amendment 7 in Enclosure 2, to identify management of reduction of heat transfer and loss of material aging effects by the Open-Cycle Cooling Water System program (B2.1.10) for heat exchanger components that have a heat transfer intended function in a ventilation atmosphere. LRA Appendix B2.1.10, and Table A4-1 item 6, have been revised as shown on LRA Amendment 7 in Enclosure 2, to identify an enhancement for visual inspection and cleaning, if necessary, the air sides of the GL 89-13 safety-related heat exchangers that have a heat transfer intended function.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, "Amendment 7, LRA Changes from RAI Responses," for a description of LRA changes with this response.

## RAI B2.1.10-5

Background:

GALL Report AMP XI.M20, “acceptance criteria,” program element states that inspected components should exhibit adequate design margin regarding design dimensions (e.g., minimum required wall thickness). SRP-LR Section A.1.2.3.6, “Acceptance Criteria,” states that acceptance criteria should ensure that the component intended function(s) are maintained consistent with all CLB design conditions during the period of extended operation. Callaway’s AMP Evaluation Report for this program, Section 3.6.2 states that minimum wall thickness acceptance criteria are listed in the procedure EDP-ZZ-1121, Attachments 3 and 4.

In its review of operating experience reports, the staff noted in CAR 200703680 that a flange for an ESW valve had corrosion damage. The Corrective Actions section states:

The extent of the corrosion damage identified does not adversely impact the structural integrity of the flange. The standard Class 3 manufacturing tolerance of 12.5% thickness provides assurance that this condition is not a structural or pressure boundary issue.

The CAR states that more than 50 percent of the gasket seating area was damaged by corrosion, but it does not provide any information regarding the depth of the corrosion.

Issue:

The acceptance criteria listed in procedure EDP-ZZ-1121, Attachments 3 and 4 only apply to pipe minimum wall thickness and do not address flange thicknesses. The 12.5 percent manufacturing tolerance, stated in the CAR, typically only applies to pipe wall thickness, and the tolerance for flange thickness is typically specified in ANSI B16.5, “Pipe Flanges and Flanged Fittings” with a 0.0 “minus” value. ANSI B16.5 does not appear to give a “plus or minus” 12.5 percent tolerance for flange thickness, and without knowing the depth of the corrosion and the thickness of the flange, the structural integrity of the flange during the period of extended operation has not been demonstrated.

Request:

For structural integrity evaluations that will be performed during the period of extended operation, where flange thicknesses have been adversely affected due to corrosion or other aging mechanisms, provide the acceptance criteria that will be used to ensure that the component intended function(s) will be maintained consistent with all CLB design conditions, or provide the bases for applying the “standard Class 3 manufacturing tolerance of 12.5 percent” to flange thicknesses.

## Callaway Response

CAR 200703680 was generated for a pipe spool flange for an ESW valve which had corrosion damage. The degradation and pitting on the original flange face was fairly shallow such that the structural integrity of the flange was not adversely impacted to the point of flange failure. However, the 12.5% that was used in the response to CAR 200703680 applies to pipe wall thickness and does not apply to flange thickness. The pipe spool piece in question has been replaced with stainless steel, therefore the current configuration maintains the structural integrity of the system.

The Callaway Operational Quality Control Manual (OQCM) section M.3, Piping System Bolted Connections, gives guidance for flange faces with flaws on the flange face. It states "No transverse discontinuities longer than 50% of gasket seat area width (25% for serrated finish surface)." From this guidance it was concluded that small pits or defects on the flange face gasket surface are allowed as long as the defect does not extend beyond 50% of the gasket seat area width.

The current corrective action process would require a Callaway Action Request (CAR) be initiated if the flange face defect exceeds the QC criteria. The CAR would then go to Engineering for evaluation. This evaluation would determine if repair, replacement, or continued operation is the appropriate action. ANSI standard B16.5, which provides design criteria for pipe flanges and flanged fittings, may be used during the evaluation to determine if the flange is capable of performing its intended function.

## Corresponding Amendment Changes

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

## RAI B2.1.10-6

Background:

SRP-LR, Section A.1.2.3.10, “Operating Experience,” states that past corrective actions for existing AMPs should be considered, and that feedback from past failures should have resulted in appropriate program enhancements or new programs.

LRA Section B2.1.10, “Operating Experience” states that buried portions of the ESW supply piping were replaced with high-density polyethylene (HDPE) piping and that sections of aboveground or underground carbon steel piping that interface with the buried piping were replaced with stainless steel. It also stated that these modifications were performed as a result of corrective actions concerning pinhole leaks, pitting, and other localized degradation of the ESW piping system. Callaway’s AMP Evaluation Report, “Scope of Program,” program element states that the carbon steel ESW system buried piping that was not replaced with HDPE, will either be replaced or will continue to be inspected to monitor internal degradation. In addition, the staff noted in the License Renewal Component List for this AMP that a number of carbon steel components are still in service, and plans for future replacements with corrosion resistant materials were not provided.

During its review of operating experience, the staff noted the discussion in CAR 200703627 that correlated the discovery of ESW system leaks with engineered safety feature actuation system (ESFAS) testing. Based on the CAR, ESW components above elevation 2037 will naturally drain with the pump secured in the ESFAS procedures, and actions taken to date have not been effective in preventing ESW system hydraulic transients during ESFAS testing. In addition, the staff noted the discussion in CAR 200608086 which stated, “other than the one incident in 2005, the impact of through-wall leaks on the ultimate heat sink inventory, piping structural integrity and room flooding, have not been significant enough to adversely affect the ability of the system to perform its intended design safety function.”

Issue:

Based on the extent of degradation in the ESW, the staff lacks sufficient information to conclude that the open-cycle cooling water System program will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. Due to the pervasive nature of degradation in the system, it is unclear to the staff what enhancements were made to this AMP or whether new programs were created to address the consequences of past program weaknesses. Since additional leaks continue to be identified, it is unclear to the staff what specific corrective actions were taken to prevent recurrence of the identified problems. In addition, based on ESFAS testing, hydraulic transient loads may be an expected load during certain CLB events and therefore, should be included in the structural evaluations for component degradation.

Request:

a) For the event in 2005 where the ability of the system to perform its intended safety function was adversely affected, provide the corrective actions that were taken and the enhancements that were made to the program which give reasonable assurance that the ESW system’s intended functions will be maintained consistent with the CLB during the period of extended operation.

b) Provide a summary of the augmented inspections that are currently being performed, to identify loss of material before through-wall leakage occurs, including inspection method(s) and frequency, number and selection of locations, and acceptance criteria. If corrective actions include plans for replacing piping, provide those aspects that can be credited in license renewal to alleviate ongoing degradation concerns. If specific inspections have not been incorporated into current site procedures, or if planned piping replacements are being credited for license renewal, provide an enhancement and an associated commitment for this program.

c) Provide a summary of analyses conducted in the past 5 years for the ESW system that evaluated the structural integrity of areas where degradation has caused pipe wall thicknesses to be less than nominal values. Include data to demonstrate that the degradation is limited to independent, localized corrosion sites or state how structural integrity has been evaluated for the potential of multiple adjacent corrosion sites that could have a cumulative adverse impact. If only independent localized corrosion sites have been discovered to date, state the basis for why multiple adjacent corrosion sites will not occur during the period of extended operation. In addition, provide a summary of any associated evaluations that considered system interactions such as flooding, spraying water on equipment, and loss of flow. Also, confirm that hydraulic transient loads, which are evident during ESFAS testing, have been included in the structural integrity calculations, or provide justification why these CLB loads do not need to be included.

## Callaway Response

a) The event in 2005 referred to by CAR 200608086 concerned a pin hole leak found in the piping section between the 'B' train Essential Service Water (ESW) pump strainer and the pump discharge valve in March, 2005. A volumetric examination of the area with the leak was performed, and it was determined that a section of the pipe measuring 12 inches by 5 inches was below the required minimum wall thickness. ESW train 'B' was declared inoperable.

The cause was determined to be under-deposit corrosion caused by an oxygen concentration gradient at a barrier between the base metal surface and the bulk water. The initiating cause of the corrosion was not determined. As corrective action, the piping section was replaced to prevent a recurrence of the under-deposit corrosion.

The extent of condition review included performing volumetric exams of the corresponding pipe section of the 'A' train and of additional locations in the 'B' train that consisted of a horizontal piping run exposed to intermittent flow. These checks indicated there were no additional failures beyond the original failure. Based on the results of these additional inspections, it is believed that the initiating cause was unique to the location where the corrosion occurred, and is no longer present. Based on this, no program enhancements were required.

b) The criteria used to select ESW inspection locations include: operating condition (areas with stagnant/intermittent flow), pipe material, piping age, pipe configuration, results of previous inspections, recent/near term challenges with the system/piping, chemistry trend data (MIC sampling), industry operating experience and system engineering recommendations. The number of selected locations varies from outage to outage based on the previously mentioned sample criteria. The inspections methods include Ultrasonic Thickness (UT), Low Frequency Electromagnetic Technique (LFET) and opportunistic visual inspections. LFET is a form of electromagnetic testing and is used specifically for screening large areas of piping quickly. The LFET scanner is moved across the pipe and will detect changes in the wall thickness of the pipe as it moves across the surface. Thinned areas found during the LFET scan are followed up with UT measurements.

A plant procedure provides acceptance criteria for minimum wall thickness for general area inspections and for localized defects. Evaluations may be used to accept a wall thickness which is less than that provided by the procedure.

In 2007/2008, Callaway conducted a three phase project to inspect above-ground carbon steel ESW piping. The first phase started in Fall 2007 in which approximately 220 feet of high risk lines was inspected using LFET. The second phase of the inspections occurred in the Spring of 2008 and covered approximately 2000 feet of ESW piping. Due to the excellent results of the phase 1 and 2 inspections, the scope for phase 3 (Fall 2008) was reduced to roughly 300 feet. Since the completion of this project, ESW piping continues to be inspected each refueling outage. In the last two refueling outages, approximately 600 feet of piping was inspected with LFET, and 200 feet is planned for the next refueling (Spring, 2013).

Callaway has replaced a substantial amount of ESW piping. Over a period of several years starting in the mid-1990s, all the small bore (four inch and smaller) carbon steel pipe, nearly 3400 feet, was replaced with 316L stainless steel pipe. From 2008 to 2009, the buried portions of the ESW supply from the ESW pump house and return to the ultimate heat sink cooling tower were replaced with high-density polyethylene (HDPE) piping. During Refuel 15 (Spring, 2007), an extensive inspection campaign resulted in the replacement of 79 feet of 30-inch piping, several sections of 8-inch and 6-inch piping, the pump discharge spool and reducer for both the 'A' and 'B' trains, and the pump discharge cross-connect spool piece. There are currently no plans for additional replacements.

c) The following provides a summary of analyses which have been performed for the ESW system since 2007:

In March, 2007, a pinhole leak was discovered in a 30-inch section of the cross tie piping. The area around the leak was pitted. The probable cause was MIC. An evaluation was performed by Dominion Engineering for stresses and by Reedy Engineering for structural integrity of the line in the vicinity of the leak. The section of piping was replaced in Refuel 15 (Spring, 2007).

In March, 2007, an inspection identified localized defects in a section of 30-inch ESW train 'B' piping. None were through-wall. The probable cause was MIC and erosion due to turbulence from an upstream butterfly valve. Evaluations performed by Dominion Engineering demonstrated the piping was structurally sound. An operability determination was also performed. The section of piping was replaced in Refuel 15 (Spring, 2007).

In March, 2007, an inspection identified localized defects below acceptable minimum wall thickness in the 'A' train supply and return piping. None were through-wall. The probable cause was MIC. Evaluations performed by Dominion Engineering demonstrated the piping was structurally sound. A prompt operability determination was also performed. The sections of piping were replaced in Refuel 15 (Spring, 2007).

In March, 2007, a pinhole leak was discovered in the 'B' train ESW supply line. The area around the leak was pitted, with some below acceptable minimum wall thickness. The probable cause was MIC and flow turbulence upstream of a butterfly valve. An evaluation performed by Dominion Engineering demonstrated the piping was suitable for continued operation. The structural integrity was analyzed using the Through Wall Flaw Approach defined in Generic Letter 90-05, as discussed in RIS 2005-20. A prompt operability determination was also performed. The leak was only 10 drops per minute, so no action was taken until the section of piping was repaired in Refuel 15 (Spring, 2007).

In May, 2007, a pinhole leak was discovered in the ESW supply line in the control building. The area around the leak was pitted. The probable cause was MIC. Code Case N-513-1 was used to demonstrate the acceptability of the piping. A prompt operability determination was also performed. A temporary patch was used to stop the leak. The section of piping was repaired in the fall of 2007.

In August, 2008, a 0.01 gallon per minute through wall pinhole leak was discovered in the buried 'A' train ESW supply piping. The probable cause was MIC. Dominion Engineering provided an evaluation for structural integrity, and an operability determination was performed. The leak was repaired in September, 2008, and the piping was subsequently replaced with HDPE.

In October, 2008, a pinhole leak of eight drops per minute was discovered in the 'B' train ESW supply line. The probable cause was MIC. The structural integrity of the pipe was confirmed in a prompt operability determination. The section of piping was repaired in 2009.

In March 2009, pits were found on both the internal and external surface of a section of train 'B' piping in the control building. Several were below design minimum wall thickness. A Callaway calculation evaluated the pits and found them acceptable through the end of Cycle 18 (Fall, 2011). Weld overlays were performed in April, 2009, and the pipe was replaced in May, 2010.

Generally, the methodology for the above analyses either assumed uniform wall thickness based on the depth of the pits, or a finite-element analysis was performed which explicitly modeled the degradation which had been found. Both of these methods are appropriate for addressing sites where multiple pits exist.

The calculations described above address only the structural integrity of the piping. When an operability determination is performed, other considerations are addressed, including inventory of the ultimate heat sink, ESW flow balance, flooding, spray impingement on nearby components, ESW pump runout, and the aggregate impact of other conditions affecting the ESW system.

At Callaway, the ESW loads are normally supplied by the service water system. When a loss of off-site power event or Engineered Safety Features Actuation System (ESFAS) testing occurs, the service water pumps stop and the ESW pumps start. Stopping the ESW flow results in column separation at higher elevations in the ESW system, and a water hammer event occurs when the ESW pumps start. Numerous plant modifications and procedure changes have been made over the years to address this problem. The water hammer event has most commonly caused leaks in the containment coolers, room coolers, and various bolted joints. CAR 200811289 performed an evaluation of the design of the ESW system with respect to the water hammer events and concluded that the events will not prevent the ESW system or sub-components from performing their intended function.

Calculations of minimum wall thickness are not required to consider the transient pressure caused by a water hammer event. The Callaway pipe design standard establishes how design pressures are defined and allows pressure/temperature excursions in excess of design for short periods of time.

## Corresponding Amendment Changes

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

## RAI B2.1.20-1

Background:

LRA Section B2.1.20 states that there are 19 socket welds in the small-bore piping population. During the audit, the applicant indicated that a recent recount by the applicant showed that there are in fact 23 Class 1 small-bore socket welds.

Issue:

Based on the applicant's previous miscount as well as the staff's experience with reviews of other LRAs for similar PWR facilities, where the typical number of in-scope socket welds are roughly twice the number indicated by the applicant, the staff is concerned that an accurate population of in-scope socket welds may not be fully represented in the applicant's LRA.

Request:

Verify and confirm the number of in-scope Class 1 small-bore socket welds in the population of ASME Code Class 1 piping. Based on this review, amend LRA Sections A1.20 and B2.1.20, to indicate the correct population of in-scope socket welds.

## Callaway Response

Callaway confirms that there are 77 ASME Class 1 small-bore socket welds less than four inches nominal pipe size (NPS) and greater than or equal to one inch NPS in the scope of AMP B2.1.20, One-Time Inspection of ASME Code Class 1 Small-Bore Piping. LRA Sections A1.20 and B2.1.20 have been revised, as shown on LRA Amendment 7 in Enclosure 2, to identify 77 ASME Code Class 1 small-bore socket welds.

## Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table, "Amendment 7, LRA Changes from RAI Responses," for a description of LRA changes with this response.

# Amendment 7, LRA Changes from RAI Responses

## Enclosure 2 Summary Table

| Affected LRA Section | LRA Page |
|---|---|
| Section 2.3.1.1 | 2.3-2 |
| Table 2.3.1-1 | 2.3-6 |
| Table 3.1.2-1 | 3.1-84 |
| Section 3.3.2.1.10 | 3.3-14 |
| Table 3.3.2-10 | 3.3-138 |
| Table 3.3.2-11 | 3.3-153, 3.3-154 and 3.3-160 |
| Table 3.3.2-13 | 3.3-168 and 3.3-172 |
| Table 3.3.2-14 | 3.3-177 and 3.3-182 |
| Table 3.3.2-15 | 3.3-185 and 3.3-188 |
| Table 3.3.2-19 | 3.3-200 and 3.3-203 |
| Table 3.4.2-2 | 3.4-36 |
| Table 4.3-5 | 4.3-30 |
| Section A1.20 | A1-11 and A1-12 |
| Table A4-1, item 6 | A-37 |
| Section B2.1.10 | B-41, B-42, B-43, and B-44 |
| Section B2.1.20 | B-72, B-73, and B-74 |

**Callaway Plant**
**License Renewal Application**
**Amendment 7**

**Insert "upper support skirt" in System Description of Reactor Vessel and Internals. (Page 2.3-2)**

## 2.3.1.1 Reactor Vessel and Internals

### System Description

The purpose of the reactor vessel is to act as a reactor coolant system (RCS) pressure boundary, acting as a barrier against the release of radioactivity generated within the reactor. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and control rod drive mechanisms (CRDMs), direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding and provide guides for the incore instrumentation.

The reactor vessel is cylindrical and has a welded, hemispherical bottom head and a removable, flanged, hemispherical upper head. The vessel is nozzle supported. The vessel contains the core, core-supporting structures, control rods, and other parts directly associated with the core. The top head also has penetrations for the CRDMs and the head vent pipe. The O-ring leak monitoring tube penetrations are in the vessel flange. The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation.

The components of the reactor internals consist of the lower core support structure (including the entire core barrel and neutron shield pad assembly), the upper core support structure, and the incore instrumentation support structure, and the alignment/interface components.

The lower core support structure includes the baffle and former plates, core barrel assembly, neutron shield panel, lower core plates with manway cover, core support forging, core support columns, secondary core support with energy absorbers, and tie plates.

The upper core support structure includes the top support plate, upper support columns, upper support skirt, upper core plate, and control rod guide tubes. The upper core support structure is featured with head cooling spray nozzles that are holes machined in the top support plate flange.

The incore instrumentation support structure consists of an upper system to convey and support thermocouples penetrating the vessel upper head and a lower system to convey and support flux thimbles penetrating the bottom head. The flux thimble guide tubes extend from the bottom of the reactor vessel to a thimble seal table.

**Callaway Plant**
**License Renewal Application**
**Amendment 7**

**Add BBVI component type "RVI Upper Core Support - Upper Support Skirt". (Page 2.3-6)**

**Table 2.3.1-1 Reactor Vessel and Internals is revised as follows (new text shown underlined):**

*Table 2.3.1-1 Reactor Vessel and Internals*

| Component Type | Intended Function |
|---|---|
| <u>RVI Upper Core Support-Upper Support Skirt</u> | <u>Structural Support</u> |

**Callaway Plant**
**License Renewal Application**
**Amendment 7**

**Revision to Table 3.1.2-1 to add aging evaluation lines for "RVI Upper Core Support - Upper Support Skirt".**

**Table 3.1.2-1 (Page 3.1-84) is revised as follows (new text shown underlined):**

*Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| RVI Upper Core Support-Upper Support Skirt | SS | Stainless Steel | Reactor Coolant (Ext) | Loss of material | Water Chemistry (B2.1.2) | IV.B2.RP-24 | 3.1.1.087 | A |
| RVI Upper Core Support-Upper Support Skirt | SS | Stainless Steel | Reactor Coolant (Ext) | Cracking | Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.6) (Existing Program Components - No Expansion Components) | IV.B2.RP-346 | 3.1.1.053 | A |

**Callaway Plant**
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**Amendment 7**

**Revision to Section 3.3.2.1.10 to remove wall thinning as an aging effect for carbon steel piping and to remove Flow Accelerated Corrosion as an aging management program in the Chemical and Volume Control System.**

**Section 3.3.2.1.10 (Page 3.3-14) is revised as follows (deleted text shown in strikethrough):**

### 3.3.2.1.10 Chemical and Volume Control System

**Aging Effects Requiring Management**

The following chemical and volume control system aging effects require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer
- ~~Wall thinning~~

**Aging Management Programs**

The following aging management programs manage the aging effects for the chemical and volume control system component types:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.8)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.11)
- External Surfaces Monitoring of Mechanical Components (B2.1.21)
- ~~Flow-Accelerated Corrosion (B2.1.7)~~
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
- Lubricating Oil Analysis (B2.1.24)
- One-Time Inspection (B2.1.18)
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping (B2.1.20)
- Selective Leaching (B2.1.19)
- Water Chemistry (B2.1.2)

**Callaway Plant**
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**Removed wall thinning as an aging effect for carbon steel piping in the Chemical and Volume Control System with an environment of steam (int).**

**Table 3.3.2-10, Chemical and Volume Control System (Page 3.3-138) is revised as follows (deleted text shown in strikethrough):**

*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 |
|---|---|---|---|---|---|---|---|---|
| ~~Piping~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Steam (Int)~~ | ~~Wall thinning~~ | ~~Flow-Accelerated Corrosion (B2.1.7)~~ | ~~VIII.B1.S-15~~ | ~~3.4.1.005~~ | ~~A~~ |

**Callaway**
**License Renewal Application**
**Amendment 7**

**Revise to add aging effect of "Reduction of heat transfer" to heat exchanger components with a heat transfer function and an external environment of ventilation atmosphere within the scope of license renewal.**

**Table 3.3.2-11 (Pages 3.3-153, 3.3-154 and 3.3-160) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 3.3.2-11 Auxiliary Systems – Summary of Aging Management Evaluation –Control Building HVAC System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Control Building HVAC) | HT | Aluminum | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 5 |
| Heat Exchanger (Control Building HVAC) | HT | Aluminum | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F1.AP-142 | 3.3.1.092 | ~~B, 1~~ E, 6 |
| Heat Exchanger (Control Building HVAC) | HT, PB | Copper Alloy | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 5 |

*Table 3.3.2-11 Auxiliary Systems – Summary of Aging Management Evaluation –Control Building HVAC System*

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Control Building HVAC) | PB | Copper Alloy | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F1.AP-109 | 3.3.1.079 | E, ~~1~~ 6 |
| Heat Exchanger (Control Building HVAC) | HT | Copper Alloy | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F1.AP-109 | 3.3.1.079 | E, ~~1~~ 6 |

Notes for Table 3.3.2-11:

Standard Notes:

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

5. Reduction of heat transfer of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

6. Loss of material of the air-side of safety-related air-to-water heat exchangers is managed by Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

**Table 3.3.2-13 (Pages 3.3-168 and 3.3-172) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 3.3.2-13 Auxiliary Systems – Summary of Aging Management Evaluation –Auxiliary Building HVAC System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Aux Bldg HVAC) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 6 |
| Heat Exchanger (Aux Bldg HVAC) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F2.AP-99 | 3.3.1.094 | ~~D, 1~~ E, 7 |

Notes for Table 3.3.2-13:

Standard Notes:

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

6. Reduction of heat transfer of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

7. Loss of material of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

**Table 3.3.2-14 (Pages 3.3-177 and 3.3-182) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 3.3.2-14 Auxiliary Systems – Summary of Aging Management Evaluation –Fuel Building HVAC System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Fuel Bldg HVAC) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 4 |
| Heat Exchanger (Fuel Bldg HVAC) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F2.AP-99 | 3.3.1.094 | ~~D, 1~~ E, 5 |

Notes for Table 3.3.2-14:

Standard Notes:
H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

4. Reduction of heat transfer of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

5. Loss of material of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

**Table 3.3.2-15 (Pages 3.3-185 and 188) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 3.3.2-15 Auxiliary Systems – Summary of Aging Management Evaluation –Miscellaneous Buildings HVAC System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Aux Feedwater Room) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 3 |
| Heat Exchanger (Aux Feedwater Room) | HT, PB | Stainless Steel | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F2.AP-99 | 3.3.1.094 | ~~D, 1~~ E, 4 |

Notes for Table 3.3.2-15:

Standard Notes:

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

3. Reduction of heat transfer of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

4. Loss of material of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

**Table 3.3.2-19 (Pages 3.3-200 and 3.3-203) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 3.3.2-19 Auxiliary Systems – Summary of Aging Management Evaluation –Containment Cooling System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger (Containment Fan Cooling Coil) | HT, PB | Copper Alloy | Ventilation Atmosphere (Ext) | Reduction of heat transfer | Open-Cycle Cooling Water System (B2.1.10) | None | None | H, 1 |
| Heat Exchanger (Containment Fan Cooling Coil) | HT, PB | Copper Alloy | Ventilation Atmosphere (Ext) | Loss of material | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)~~ Open-Cycle Cooling Water System (B2.1.10) | VII.F3.AP-109 | 3.3.1.079 | E, ~~1~~ 2 |

Notes for Table 3.3.2-19:

Standard Notes:

H Aging effect not in NUREG-1801 for this component, material and environment combination.

Plant Specific Notes:

1. Reduction of heat transfer of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

2. Loss of material of the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System program (B2.1.10) consistent with Callaway commitments to GL 89-13.

**Callaway Plant**
**License Renewal Application**
**Amendment 7**

**Remove wall thinning as an aging effect for carbon steel silencers in the main steam supply system with an environment of Steam (Int). No new Plant Notes are added.**

**Table 3.4.2-2, Main Steam Supply System (Page 3.4-36) is revised as follows (deleted text shown in strikethrough):**

*Table 3.4.2-2 Steam and Power Conversion System – Summary of Aging Management Evaluation – Main Steam Supply System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| ~~Silencer~~ | ~~LBS, SIA~~ | ~~Carbon Steel~~ | ~~Steam (Int)~~ | ~~Wall thinning~~ | ~~Flow-Accelerated Corrosion (B2.1.7)~~ | ~~VIII.B1.S-15~~ | ~~3.4.1.005~~ | ~~A~~ |

**Remove Thermal Shield Flexures add Neutron Panel Bolts.**

**Table 4.3-5, Reactor Internals Design Basis Fatigue Analysis Results (Page 4.3-30) is revised as follows (new text underlined and deleted text is shown in strikethrough):**

*Table 4.3-5 Reactor Internals Design Basis Fatigue Analysis Results*

| Component | CUF |
|---|---|
| Lower Support Columns | 0.270 |
| Core Barrel Nozzle | 0.762 |
| Lower Core Plate Assembly Perforated Region | 0.0744 |
| Upper Core Plate | 0.183 |
| Lower Support Plate | 0.183 |
| Radial Key Weld | 0.001 |
| Baffle-Former Bolts | Qualified by test<br>CUF < 1 |
| Barrel-Former Bolts | Qualified by test<br>CUF < 1 |
| Guide Tubes | 0.102 |
| Upper Support Plate Assembly | 0.094 |
| Baffle Edge Bolts | Qualified by Test<br>CUF < 1 |
| Lower Core Barrel | 0.351 |
| Upper Core Barrel | 0.155 |
| Guide Cards | 0.083 |
| Guide Tube Lower Flange | 0.946 (bottom flange weld)<br>0.009 (bottom flange) |
| ~~Thermal Shield Flexures~~ Neutron Panel Bolts | 0.978 |
| Hold Down Spring | 0.004 |

# A1.20 ONE-TIME INSPECTION OF ASME CODE CLASS 1 SMALL-BORE PIPING

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of ASME Code Class 1 piping less than four inches nominal pipe size (NPS 4) and greater than or equal to NPS 1.

For ASME Code Class 1 small-bore piping, the Risk-informed (RI-ISI) ISI program requires volumetric examinations (by ultrasonic testing) on selected butt weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*. Ultrasonic examinations are conducted in accordance with ASME Section XI with acceptance criteria from paragraph IWB-3000 for butt welds.

The program will include a volumetric or opportunistic destructive examination of socket welds to identify potential cracking. Callaway has experienced one case of cracking, in 1995, of an ASME Code Class 1 small-bore piping butt weld resulting from cyclical loading which was mitigated with a design change to prevent recurrence. ~~Two~~ Eight small-bore Class 1 socket welds will be selected for examination, which represents 10 percent of the population. There are ~~19~~ 77 Class 1 small-bore socket welds in the population of ASME Code Class 1 piping less than NPS 4 and greater than or equal to NPS 1 at Callaway. Alternatively, an opportunistic destructive examination may be used in lieu of volumetric examinations. An opportunistic destructive examination may be performed when a weld is removed from service for reasons other than inspection.

Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. If a qualified volumetric examination procedure for socket welds endorsed by the industry or the NRC is available and incorporated into the ASME Section XI Code at the time of the small-bore inspections, then this will be used for the volumetric examinations. If no volumetric examination procedure for ASME Code Class 1 small-bore socket welds has been endorsed by the industry or the NRC and incorporated into ASME Section XI at the time Callaway performs inspections of small-bore piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

The program includes controls to implement an alternate plant-specific periodic inspection aging management program should evidence of ASME Class 1 small bore piping cracking caused by intergranular stress corrosion cracking or fatigue be confirmed by review of Callaway operating experience prior to the period of extended operation or by the examinations performed as part of this program.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is a new program and inspections will be completed and evaluated within six years prior to the period of extended operation.

In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval. Callaway will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the 10-year period prior to the period of extended operation (fourth interval).

*Table A4-1 License Renewal Commitments*

| Item # | Commitment | LRA Section | Implementation Schedule |
|---|---|---|---|
| 6 | Enhance the Open-Cycle Cooling Water System program procedures to:<br>• include polymeric material inspection requirements, parameters monitored, and acceptance criteria. Examination of polymeric materials by OCCW System program will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.<br>• inspect the essential service water strainers for coating degradation.<br>• include inspection and cleaning, if necessary, of the air-side of safety-related air-to-water heat exchangers cooled by essential service water | B2.1.10 | Prior to the period of extended operation |

## B2.1.10 Open-Cycle Cooling Water System

### Program Description

The Open-Cycle Cooling Water (OCCW) System program manages loss of material, reduction of heat transfer, cracking, blistering, change in color, and hardening and loss of strength for those components that are exposed to the raw water environment of the essential service water (ESW) system and heat exchangers and other components in other systems serviced by the essential service water system.

The activities for this program are consistent with the Callaway commitments to the requirements of NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components* and provide for management of aging effects in raw water cooling systems through tests, inspections and component cleaning. System and component testing, visual inspections, nondestructive examination (i.e., ultrasonic testing and eddy current testing), and biocide and chemical treatment are conducted to ensure that aging effects are managed such that system and component intended functions and integrity are maintained.

Periodic heat transfer testing or inspection and cleaning of heat exchangers with a heat transfer intended function is performed in accordance with Callaway commitments to NRC Generic Letter 89-13 to verify heat transfer capabilities.

Routine inspections and maintenance of the OCCW System program ensure that corrosion, erosion, sediment deposition and biofouling cannot degrade the performance of safety-related systems serviced by the essential service water system.

The guidelines of NRC Generic Letter 89-13 are utilized for the surveillance and control of biofouling. Procedures provide instructions and controls for biocide injection. Periodic inspections are performed for the presence of mollusks and biocide treatments are applied as necessary.

System walkdowns are performed periodically to assess the material condition of OCCW system piping and components. Compliance with the licensing basis is ensured by review of system design basis documents as well as periodic performance of self assessments.

Callaway uses internal coatings only on the component cooling water heat exchanger end bells, channels, and tubesheets; the control room air conditioner tubesheets; the class 1E electrical equipment air conditioner tubesheets; and the essential service water system strainers. This amount of coating surface area is relatively small and its aging has not been a concern for essential service water system performance.

Examination of polymeric materials by OCCW System program will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.23).

The external surfaces of the buried OCCW components are managed by the Buried and Underground Piping and Tanks program (B2.1.25). The aging management of closed-cycle cooling water systems is described in B2.1.11, Closed Treated Water Systems program, and is not included as part of this program.

**NUREG-1801 Consistency**

The Open-Cycle Cooling Water System program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI.M20, *Open-Cycle Cooling Water System*.

**Exceptions to NUREG-1801**

None

**Enhancements**

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

*Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)*

Procedures will be enhanced to include polymeric material inspection requirements, parameters monitored, and acceptance criteria. Examination of polymeric materials by OCCW System program will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.23).

Procedures will be enhanced to include inspection and cleaning, if necessary, of the air-side of safety-related air-to-water heat exchangers cooled by essential service water.

*Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)*

Procedures will be enhanced to inspect the essential service water strainers for coating degradation.

**Operating Experience**

The following discussion of operating experience provides objective evidence that the Open-Cycle Cooling Water System program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation:

1. In 2000, during routine maintenance, Asiatic clams were found in an RHR room cooler, blocking approximately 15 percent of the tubes. In subsequent inspections, clams were found in several service water and essential service water heat exchangers and room coolers. It was determined that the clams originated in the waste treatment clearwell, from which they were flushed into the suction of the service water pumps. The service water pumps distributed the clams to the heat exchangers and room coolers. As corrective action, procedures were strengthened to require more frequent inspections and provide for a more robust chemistry program to control the clams. Corrective action also included plant modifications, such as installing strainers on the discharge line of the service water pumps.

2. In 2001, through-wall corrosion had been observed in the RHR pump room cooler. The exact cause could not be determined but was believed to be from microbiologically influenced corrosion attack. The cooler was repaired.

3. Performance of the containment coolers degraded over time due to debris from the service water system, so that by 2001 there was very little margin available. The design of the original containment cooler coils did not allow them to be mechanically cleaned, and flushing was ineffective. The coils for containment coolers A and B were replaced in Refuel 11 (Spring 2001), and the coils for C and D were replaced in Refuel 12 (Fall 2002). The replacement coils have a removable cover plate which permits access to mechanically clean individual tubes.

4. In 2007, Callaway revised the program so that the component cooling water heat exchangers are the only heat exchangers that are performance tested. In order to maintain heat removal capability of the other NRC Generic Letter 89-13 heat exchangers, Callaway cleans and inspects heat exchangers at regular intervals, as well as performs flow and pressure measurements according to the essential service water flow balance procedure. The inspections check for micro-fouling, and include thermographies or ultrasonic examinations of internal surfaces. These maintenance activities supplement the commitment to thermal performance testing made in response to NRC Generic Letter 89-13. The primary and additional monitoring methods have been determined for each of the NRC Generic Letter 89-13 heat exchangers, in accordance with the guidance of EPRI Technical Report 1007248, *Alternative to Thermal Performance Testing and/or Tube-side Inspections of Air-to-Water Heat Exchangers*.

5. From 2008 to 2009, the buried portions of the ESW supply from the ESW pump house and return to the ultimate heat sink cooling tower were replaced with high-density

polyethylene (HDPE) piping. In addition, sections of above ground or underground carbon steel piping that interfaces with the buried piping was replaced with stainless steel piping. These modifications were performed as a result of the material condition of the ESW system. These modifications were performed as a result of corrective action documents that have been written concerning pinhole leaks, pitting, and other localized degradation of the ESW piping system.

6. In 2009, the replacement of the emergency diesel generator jacket water heat exchangers was evaluated due to loss of material in the tubes. The evaluation determined that a better material of construction and a better design would minimize aging effects due to raw water environment in the emergency diesel generators. The replacement jacket water heat exchangers and the emergency diesel generator lube oil coolers had tubes made of AL6XN stainless steel and were replaced in Refuel 17 (Spring 2010). The emergency diesel generator intercoolers were replaced in Refuel 18 (Fall 2011), and also have tubes fabricated from AL6XN stainless steel.

7. In 2009, room cooler flow rates had been observed to be low in the RHR pump room cooler and the containment spray pump room cooler. The low flow rates were determined to be from material that was dislodged during weld repairs from the outage prior to flow testing. The coolers were flushed to remove the debris, and flow rates were restored to their normal operating condition.

8. Prior to 2010, the coils for the following safety-related room coolers were replaced due to performance or aging issues: auxiliary building north penetration room cooler, auxiliary building south penetration room cooler, component cooling water pump room cooler train A, component cooling water pump room cooler train B, and spent fuel pool room cooler A. The material for the replacement coils is AL6XN stainless steel.

The above examples provide objective evidence that the existing Open-Cycle Cooling Water System program preventive, condition, and performance monitoring activities prevent or detect aging effects. Occurrences that would be identified under the Open-Cycle Cooling Water System program will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for re-evaluation, repair, or replacement is provided for locations where aging is found. There is confidence that the continued implementation of the Open-Cycle Cooling Water System program will effectively identify aging prior to loss of intended function.

**Conclusion**

The continued implementation of the Open-Cycle Cooling Water System program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

## B2.1.20 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

### Program Description

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of ASME Code Class 1 piping less than four inches nominal pipe size (NPS) and greater than or equal to NPS 1.

For ASME Code Class 1 small-bore piping, the Risk-informed (RI-ISI) ISI program requires volumetric examinations (by ultrasonic testing) on selected butt weld locations to detect cracking. Weld locations are selected based on the guidelines provided in EPRI TR-112657, *Revised Risk-Informed Inservice Inspection Evaluation Procedure.* There are 340 Class 1 small-bore butt welds less than NPS 4 and greater than or equal to NPS 1 at Callaway. At least 25 butt welds will be included in the examination population. Ultrasonic examinations are conducted in accordance with ASME Section XI with acceptance criteria from paragraph IWB-3000 for butt welds.

The program will include a volumetric or opportunistic destructive examination of socket welds to identify potential cracking. Callaway has experienced one case of cracking, in 1995, of an ASME Code Class 1 small-bore piping butt weld resulting from cyclical loading which was mitigated with a design change to prevent recurrence. ~~Two~~ Eight small-bore Class 1 socket welds will be selected for examination, which represents 10 percent of the population. There are ~~19~~ 77 Class 1 small-bore socket welds in the population of ASME Code Class 1 piping less than NPS 4 and greater than or equal to NPS 1 at Callaway. Alternatively, opportunistic destructive examinations may be used in lieu of a volumetric examination. An opportunistic destructive examination may be performed when a weld is removed from service for reasons other than inspection. When selecting socket welds for examination, consideration will be given to selecting welds which are susceptible to cracking resulting from stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. At least one socket weld selected for examination will have a risk ranking of "high", as determined by the RI-ISI program.

Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. If a qualified volumetric examination procedure for socket welds endorsed by the industry or the NRC is available and incorporated into the ASME Section XI Code at the time of the small-bore inspections, then this will be used for the volumetric examinations. If no volumetric examination procedure for ASME Code Class 1 small-bore socket welds has been endorsed by the industry or the NRC and incorporated into ASME Section XI at the time Callaway performs inspections of small-bore piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

The program includes controls to implement an alternate plant-specific periodic inspection aging management program should evidence of ASME Class 1 small bore piping cracking caused by intergranular stress corrosion cracking or fatigue be confirmed by review of Callaway operating experience prior to the period of extended operation or by the examinations performed as part of this program.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program inspections will be completed and evaluated within the six-year period prior to the period of extended operation.

In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval. Callaway will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the 10 year period prior to the period of extended operation (fourth interval).

**NUREG-1801 Consistency**

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is a new program that, when implemented, will be consistent with NUREG-1801, Section XI.M35, *One-Time Inspection of ASME Code Class 1 Small-Bore Piping.*

**Exceptions to NUREG-1801**

None

**Enhancements**

None

**Operating Experience**

The following discussion of operating experience provides objective evidence that the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation:

1 A review of plant-specific operating experience indicates that one event of cracking has been observed for an ASME Code Class 1 small-bore pipe butt weld less than NPS 4. In 1995, an ASME Class 1 butt weld on a two inch RCS Loop D crossover leg to chemical and volume control system excess letdown line developed a crack. The most probable cause was the combined effects of 1) high stresses resulting from interference with a flange/plate and 2) normal system vibration. The flange/plate was removed to prevent recurrence of this weld failure. A volumetric examination (UT) of the weld performed during Refuel 17 (Spring 2010) using the techniques described in MRP-146 identified no indications. There have been no additional failures since 1995.

Occurrences that would be identified under the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for re-evaluation, repair, or replacement is provided for locations where aging is found. There is confidence that the implementation of the One Time Inspection of ASME Code Class 1 Small Bore Piping program will effectively identify aging prior to loss of intended function.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

**Conclusion**

The implementation of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program will provide reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

# Updates to Previous RAI Responses

| **RAI** |
| --- |
| 3.3.1-1 |
| B2.1.14-2 |
| B2.1.25-2 |

## RAI 3.3.1-1

Background:

The LRA cites SRP-LR items 3.3.1-112 and 3.3.1-120 for steel and stainless steel piping, piping components, and other component types embedded in concrete.

SRP-LR item 3.3.1-112 addresses steel piping, piping components, and piping elements exposed to concrete for which there is no recommended aging effect requiring management (AERM) or AMP, “provided 1) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete.” SRP-LR item 3.3.1-120 addresses stainless steel piping, piping components, and piping elements exposed to concrete as well as other environments (e.g., air –indoor, uncontrolled, gas, dry air) for which there is no recommended AERM or AMP.

The “program description” of GALL Report AMP XI.M41 states, “[t]he terms ‘buried’ and ‘underground’ are fully defined in Chapter IX of the GALL Report.” Briefly, buried piping and tanks are in direct contact with soil or concrete (e.g., a wall penetration). The “scope of program” program element of GALL Report AMP XI.M41 states, “[t]his program is used to manage the effects of aging for buried and underground piping and tanks constructed of any material including metallic, polymeric, cementitious, and concrete materials.”

Issue:

There is an internal misalignment in the GALL Report in that the definition of buried piping and scope of AMP XI.M41 conflicts with items 3.3.1-112 and 3.3.1-120, which state that there is no AERM or recommended AMP for the concrete environment. Regardless of the misalignment, the staff lacks sufficient information to conclude that the in-scope steel and stainless steel piping and piping components embedded in concrete do not need to be age managed. For example, if

steel piping is embedded in concrete, is within a building or under a building but above the water table, the potential for water intrusion into the concrete is very low, and therefore, the conditional statements associated with SRP-LR item 3.3.1-112 represent a sufficient basis for why there are no aging effects for these items.

Request:

For in-scope steel and stainless steel piping and piping components embedded in concrete, state the basis for why there are no aging effects for these items, or provide any necessary corrections to the LRA to reflect the change.

## Callaway Response

Callaway has the following steel or stainless steel components within the scope of license renewal that are embedded in concrete:

- Floor and equipment drains which are located inside of buildings
- Metal dampers embedded in concrete
- Essential service water system piping that is embedded in concrete as it transitions between rooms in the ultimate heat sink cooling tower.
- Structural steel anchorages

These components are embedded in concrete and are within a building where the potential for water intrusion into the concrete is very low, and therefore the conditional statements associated with SRP-LR item 3.3.1-112 provide a sufficient basis of no aging effects. There has been no plant operating experience to show that metallic components embedded in concrete experience any aging effects.

Callaway has no steel or stainless steel piping or piping components within the scope of license renewal that transition directly from a buried environment to an embedded in concrete environment. Buried piping which enters buildings at Callaway passes through sleeved penetrations in the building walls which have elastomeric water seals to prevent moisture intrusion into the building.

## **Corresponding Amendment Changes**

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

## RAI B2.1.14-2

Background:

GALL Report AMP XI.M27, "Fire Water System," recommends that sprinklers be tested in accordance with applicable NFPA codes and standards. NFPA 25 states that any sprinklers that show signs of physical damage, corrosion, or loading shall be replaced. LRA Section B2.1.14, "Fire Water System," states in the first operating experience example of the "operating experience" program element, that during sprinkler head inspections in 2005, 10 sprinkler heads were found with corrosion or damage. The LRA also states that two sprinkler heads were replaced and the rest were cleaned. Review of Callaway Action Request (CAR) 200502420 during the audit identified that there were four sprinklers with damage, three with corrosion, and three with lint, but only two were documented as being replaced.

Issue:

It is unclear to the staff why only two of the sprinklers with identified damage, corrosion, or loading were replaced. This does not appear to be consistent with the guidance in NFPA 25, and therefore does not appear to be consistent with the recommendations in the GALL Report.

Request:

Explain why some of the corroded/damaged sprinklers were not replaced. Explain why this is consistent with the guidance in NFPA 25 and GALL Report AMP XI.M27.

## Callaway Response

The staff review of internal operating experience identified the following instances where the as-found condition of sprinkler system nozzles was degraded but they were not replaced. The subject nozzles were evaluated to be fully functional as part of the remedial actions documented in the Corrective Action Program. ~~Seven (7)~~ Six (6) of the subject nozzles required minor cleaning to remove lint/oil or removal of minor corrosion which was equivalent to a "tarnish." Diffusers on two (2) of the nozzles were bent and were straightened or replaced. The two nozzles with the bent diffusers are part of the Turbine Generator Bearing Water Spray System. The Turbine Generator Bearing Water Spray System was replaced in 2007 with a Pre-Action Sprinkler System.

As noted in the RAI (issue above), two (2) sprinklers were replaced due to loose brass rings and spinner damage.

## Corresponding Amendment Changes

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

## RAI B2.1.25-2

Background:

The “preventive actions” program element of the Buried and Underground Piping and Tanks program states that coatings for buried stainless steel piping are only required to protect from a chloride environment to prevent SCC. In addition, it states that the design temperature of the ultimate heat sink is 95°F and the maximum temperature of the refueling water storage tank is 120°F. The basis document further states that these temperatures are below the threshold temperature for SCC as stated in GALL Report Section IX.D.

GALL Report AMP XI.M41, Table 2a, Preventive Actions for Buried Piping and Tanks, footnote 3 states, “[c]oatings are provided based on environmental conditions (e.g., stainless steel in chloride containing environments). If coatings are not provided, a justification is provided in the LRA.”

GALL Report Section IX.D states:

> Temperature threshold of 140°F (60°C) for SCC in stainless steel: Stress corrosion cracking (SCC) occurs very rarely in austenitic stainless steels below 140°F (60°C). Although SCC has been observed in stagnant, oxygenated borated water systems at lower temperatures than this 140°F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. With a harsh enough environment (i.e., significant contamination), SCC can occur in austenitic stainless steel at ambient temperature. However, these conditions are considered event-driven, resulting from a breakdown of chemistry controls.

Issue:

The staff recognizes that GALL Report Section IX.D states a 140°F threshold for SCC in stainless steel components; however, in contrast to the treated water environments, the soil environment is not controlled to preclude the potential for significant levels of contaminants. Given that contaminants can accumulate in the soil due to normal environmental interactions, the 140°F threshold may not apply to buried piping. In addition, the GALL Report, item AP-137, states that stainless steel components exposed to soil are susceptible to loss of material due to pitting and crevice corrosion.

During the AMP audit, the applicant did not provide any documentation demonstrating that the soil in the vicinity of the buried stainless steel piping had sufficiently low levels of contaminants to preclude pitting and crevice corrosion, and SCC. If soil sample results are not available or they reveal contaminant levels that could result in pitting and crevice corrosion, and SCC, the staff believes that augmented inspections of buried piping beyond those recommended in Table 4a of GALL Report AMP XI.M41 could be utilized to demonstrate that the aging effects are not occurring.

Request:

Provide the results of soil sampling in the vicinity of in-scope buried uncoated stainless steel piping that demonstrate that loss of material due to pitting and crevice corrosion, and SCC will not occur due to exposure to contaminants in the soil. If this is not the case, state how these aging effects will be managed.

## Callaway Response

A recent soil survey was performed on four locations in the same excavation ditch and was analyzed on July 9, 2012. The excavation ditch contained two stainless steel pipes within the scope of license renewal. The soil samples were taken from a single excavation site. The excavation site was plant south in the radwaste yard. The excavation was 15'X12'X12'. Four soil samples were collected at random while hand digging was taking place.

The soil survey analysis results for all four locations indicate that the stainless steel piping is buried in a non-aggressive environment. Key analysis results that substantiate a non-aggressive environment are:

ph: 7.6 to 8.0 (slightly alkaline)
chlorides: less than 2.7 ppm
as-received resistivity above 10,000 ohm-cm
redox potential in the range of -44 to 17 mV

The low level of chloride content and slightly alkaline environment of the soil combined with an internal pipe operating environment less than 140 degrees Fahrenheit indicate sufficiently low levels of contaminants to preclude an aggressive environment that would promote pitting, crevice and stress corrosion cracking.

## Corresponding Amendment Changes

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