CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

REQUEST FOR ADDITIONAL INFORMATION (RAI) Set #3 RESPONSES

RAI B2.1.8-1

Background:

GALL Report AMP XI.M18, "Bolting Integrity," manages aging of closure bolting for pressure retaining components. The program includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc.

Between 1985 and 1987, Callaway installed seal cap enclosures on four swing check valves to mitigate gasket leakage from the bolted body-to-bonnet flange joint. The seal cap enclosures have since been removed, however it is not clear to the staff whether additional seal cap enclosures have been installed or if seal cap enclosures are still used at the site to mitigate leakage.

Issue:

The use of seal cap enclosures as mitigation for leakage may prevent the bolting within the enclosure from being managed for the loss of preload, cracking, and loss of material aging effects since it prevents direct inspection of the bolted joint.

Request:

a) Clarify whether there is any pressure-retaining bolting surrounded by seal cap enclosures at Callaway Plant Unit 1.

b) For all instances where pressure-retaining bolting is surrounded by seal cap enclosures:

   i. Describe the bolting alloy and the leaking water environment (i.e., reactor coolant, secondary water).

   ii. Describe how the bolting will be managed for loss of material, loss of preload, and cracking due to stress corrosion cracking (SCC), as appropriate, in the submerged environment. Provide technical justification for any cases where cracking due to SCC is not included as an applicable aging effect.

   iii. If the aging management approach in item (b) does not include direct inspection of the bolting, provide technical justification for how the aging effects will be effectively managed during the period of extended operation.

c) Describe how the use of seal cap enclosures is controlled such that aging is managed as described in b.ii.

Callaway Response

a) Callaway Plant had seal cap enclosures installed on two check valves in the normal charging line and two check valves in the alternate charging line. The charging line check valve seal cap enclosures were removed in 2002 and 2004. There are no additional documented seal cap enclosures installed at the Callaway Plant for valves within the scope of license renewal.

b) There are no documented seal cap enclosures installed at the Callaway Plant for valves within the scope of license renewal.

c) There are no documented seal cap enclosures installed at the Callaway Plant for valves within the scope of license renewal. Thus, management of aging of bolting within seal cap enclosures will not be required.

Corresponding Amendment Changes

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

RAI B2.1.9-1

NEI 97-06, Revision 3, “Steam Generator Program Guidelines,” was to be implemented by September 1, 2011. The Technical Specification (TS) for Steam Generator Maintenance Services (S-1032) was used for the Refuel 18 steam generator tube inspections (which commenced after October 15, 2011). This document (S-1032) references NEI 97-06, Revision 2 in Section 4.2.A.4. The staff requests the applicant to discuss whether NEI 97-06 Revision 2 or NEI 97-06 Revision 3 was used during the Refuel 18 inspections. If NEI 97-06 Revision 2 was used, the staff requests the applicant to provide the deviation supporting this exception to the industry guidelines.

Callaway Response

Prior to Refuel 18, the Technical Specification for Steam Generator Maintenance Services (S-1032) was approved prior to the implementation of NEI 97-06 Revision 3. S-1032 is a specification for a contractor to provide steam generator inspection services and is not used as a procedure to perform steam generator inspections. All implementation procedures for Steam Generator inspections conducted during Refuel 18 reference and were governed by NEI 97-06 Revision 3. Future revisions of the Technical Specification for Steam Generator Maintenance Services (S-1032) will reference NEI 97-06 Revision 3.

Corresponding Amendment Changes

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

RAI B2.1.9-2

The term active degradation is used in EDP-BB-01341, “Steam Generator Surveillance” (e.g., refer to Sections 4.4.1.4, 4.9.7.c, and 7.1). This term, as originally defined, was misleading and is no longer used in the Pressurized Water Reactor Steam Generator Examination Guidelines, which were issued in 2007. The staff requests the applicant to discuss its plans for removing this term from its procedures.

Callaway Response

EDP-BB-01341, Steam Generator Surveillance, procedure sections 4.4.1.a.4, 4.9.6.c.3, 4.9.7.c, 4.9.7.e.3, 4.10.2.a, and 7.1 have been revised to remove references to the term "active degradation" and reference the term “existing degradation”, "degradation", or "degradation mechanism" to be consistent with EPRI 1019038, Steam Generator Integrity Assessment Guidelines, and EPRI 1013706, Pressurized Water Reactor Steam Generator Examination Guidelines.

Corresponding Amendment Changes

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

RAI B2.1.9-3

Section 4.1.2.c.3 of EDP-BB-01341, “Steam Generator Surveillance” indicates that if implementation of a guideline change cannot be performed within three months of the due date that a deviation should be processed. This appears to permit implementing the guideline change three months after the due date. Please clarify where this three month “extension” is permitted by the industry guidelines (i.e., if the forwarding letter indicates the guideline change should be implemented by a specific date, it is not clear that a three month automatic extension is justified). If the three month “extension” is not permitted by industry guidance documents, the staff request[s] the applicant to discuss its plans to change its procedures.

Callaway Response

EDP-BB-01341, Steam Generator Surveillance, procedure section 4.1.2.c.3 has been revised to remove the three month extension for implementation of a guideline change and now states "IF implementation CANNOT be performed PROCESS a deviation".

Corresponding Amendment Changes

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

RAI B2.1.9-4

Section 4.5.1 of EDP-BB-01341, “Steam Generator Surveillance” deals with secondary side inspections; however, Section 4.5.1.a refers to primary side maintenance activities. This appears to be a typographical error. Please clarify.

Callaway Response

EDP-BB-01341, Steam Generator Surveillance, procedure section 4.5.1.a has been revised to correct a typographical error and reference the secondary side.

Corresponding Amendment Changes

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

RAI B2.1.9-5

Section 4.10.3 of EDP-BB-01341, "Steam Generator Surveillance" requires the condition monitoring report to be completed within 30 days following completion of the outage; however, Section 4.9.6.a.1 requires the condition monitoring report to be completed prior to Mode 4 after a steam generator inspection. The Electrical Power Research Institute (EPRI) Steam Generator Integrity Assessment Guidelines (Section 11.2.2) requires the condition monitoring assessment to be completed prior to Mode 4. The staff requests the applicant to discuss its plans to make its procedures consistent with the industry guidelines.

Callaway Response

EDP-BB-01341, Steam Generator Surveillance, procedure section 4.10.3.c has been revised to ensure the Condition Monitoring Report is completed prior to Mode 4.

Corresponding Amendment Changes

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

RAI B2.1.9-6

Section 4.8.5.e of EDP-BB-01341, “Steam Generator Surveillance” refers to “degradation of interest” rather than “existing and potential degradation” as discussed in the EPRI Steam Generator Integrity Assessment Guidelines (Section 6.2). The staff requests the applicant to discuss whether “degradation of interest” is defined in its procedures. If not, the staff requests the applicant to discuss its plans to modify its procedures to ensure they are consistent with the industry guidelines.

Callaway Response

EDP-BB-01341, Steam Generator Surveillance, procedure section 4.8.5.e has been revised to refer to existing and potential degradation mechanisms and now states "IDENTIFY the limiting structural integrity performance criteria and the appropriate loading conditions for existing and potential degradation mechanisms (i.e. 3 Delta P vs. 1.4 times accident pressure including primary vs. secondary loading)."

Corresponding Amendment Changes

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

RAI B2.1.9-7

AREVA NP Inc, Document No. 51-9172264-000, “Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21” does not appear to justify the length of the operating interval for secondary side degradation. Section 10.3 of the EPRI Steam Generator Integrity Assessment Guidelines indicates that the operational assessment shall include a justification for operating the planned interval between secondary side inspections as well as primary side inspections. Please discuss whether there is a justification for the planned operating interval that addresses degradation of secondary side internals.

Callaway Response

The first paragraph of Section 10 of document 51-9172264-00 identifies the forms of degradation detected in the Callaway Unit-1 replacement steam generators at the 1R18 outage. These mechanisms were AVB and TSP wear. There was no degradation associated with the secondary side findings (inner bundle or steam drum). The intent of the operational assessment was to address currently detected and/ or previously detected degradation mechanisms located on both the primary and secondary sides of the Steam Generators (SGs). Since the secondary side findings revealed no degradation, discussion was limited to the condition monitoring results located in Section 6.2 of the document.

Section 6.2 of document 51-9172264-00 identifies the Secondary side activities performed at 1R18. These activities included steam drum inspections in SGB and SGC, foreign object and PLP inspections in all four SGs, and sludge lancing in all four SGs. The steam drum inspections revealed no loose parts or loose hardware detected in the steam drum of either SG. The only anomaly noted was two buckles on one of the sectors associated with the loose part trapping screens. This condition was pre-existing and not new. The foreign object and PLP inspections revealed no PLPs or foreign object degradation detected in any SG based on eddy-current inspections. The FOSAR inspections (post-lancing) detected only a small piece of scale in the cold-leg of SGA. The sludge lancing results revealed that only minimal amounts of sludge were contained within each of the four SGs.

The findings at 1R18 echoed the findings at 1R15 (with exception of the single small piece of scale detected in the cold leg of SGA). Based on two consecutive outages of exceptional secondary side inspection results, any projected secondary side degradation is expected to be minimal and to not compromise tube integrity for the planned operating interval.

Corresponding Amendment Changes

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

RAI B2.1.9-8

Section 8.6 of the EPRI Steam Generator Integrity Assessment Guidelines indicates, in part, that (1) failure to meet condition monitoring requirements means that the projections of the previous operational assessment were not conservative and that necessary corrective actions shall be identified and (2) even if condition monitoring requirements are met, a comparison of condition monitoring results with the projections of the previous operational assessment shall be performed and that this comparison shall be completed prior to issuance of the final operational assessment since adjustment of input parameters may be required.

In AREVA NP Inc, Document No. 51-9172264-000, "Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21" there is a statement that the latter must be performed, but then the report went on to indicate that the assumptions and uncertainties included in the previous operational assessment are validated since none of the detected indications approach the condition monitoring limit and that additional discussions below provide further details. The staff could not locate these additional discussions. In addition, in reviewing the previous operational assessment, the staff could not locate any specific projections such that a comparison of the as-found and previously projected conditions could be compared. It is not clear that the intent of the EPRI requirement has been met. Please clarify. The staff notes that the operational assessment is supposed to be conservative. As a result, even if the actual detected conditions are near (including "slightly" below) the projections from the prior operational assessment, this could indicate a potential non-conservative assessment which may lead to issues in the future if not corrected.

Callaway Response

Additional Discussions of Structural Integrity and Leakage Integrity:

The additional discussions, although not specifically referenced, are located in Section 7.2 (Structural Results) and Section 7.3 (Leakage Results) of document 51-9172264-000.

> Section 7.2 discusses how structural integrity was met at 1R18. Also discussed is justification for use of the Axial Partial Through-wall Degradation < 135° model. Condition monitoring curves (Figures 7-1 and 7-2) illustrate structural integrity being met for AVB wear and TSP wear respectively. Even for the bounding case of flat wear profiles, notwithstanding the fact that most profiles had rounded corners, structural integrity was still satisfied. Note also that each indication's percent through-wall (%TW) was small enough such that condition monitoring could be treated as length independent, for all practical purposes.
>
> Section 7.3 discusses how leakage integrity was met at 1R18. Since wear indications leak and break at essentially the same differential pressure, leakage integrity at the lower faulted differential pressure of 3648 psid (resulting from a feedwater line break * 1.4) was satisfied since structural integrity, at the more limiting 3ΔP of 4200 psid, was also demonstrated.

Projections of Previous Operational Assessments:

Section 5.0 (Operational Assessment) of this report implicitly projects EOC18 %TWs by the addition of growth to the return to service %TW population. Both the growth rates and the calculated repair limits are defined in Table 5-1 of document 51-9048595-000. The repair limit corresponds to the largest BOC16 %TW that could sustain the generator specific %TW growth

and still satisfy EOC18 structural integrity. For example, using the values shown in Table 5-1 for (all SGs), the projected upper 95th percentile (at 50% confidence) growth rate is 8.5 %TW/ EFPY. The actual observed 95/50 growth rate at EOC18 (all SGs) was 5.5 %TW/ EFPY. Returning to service the maximum %TW detected at 1R15 (14 %TW) and applying the 8.5 %TW/ EFPY growth rate over three cycles (4.2 EFPY) projects the EOC18 maximum percent through-wall to be 50 %TW, without consideration for NDE uncertainty. The largest NDE %TW actually detected at EOC18 was 39 %TW.

In both cases, the implied projections of the 1R15 OA (growth rates and EOC %TW) were satisfied with adequate margin, at EOC18, as demonstrated by the condition monitoring results.

Corresponding Amendment Changes

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

RAI B2.1.11-1

Background:

The LRA states that representative samples of each combination of material and water treatment program are visually inspected every 10 years. LRA Section B2.1.11, “Closed Treated Water Systems,” states that the aging management program (AMP) uses four treatment programs for chemistry control, including molybdate control with tolyltriazole (TTA), ethylene glycol, nitrite control with TTA, and Diesel Coolant Additive and ethylene glycol.

During its audit of the applicant’s onsite documentation, the staff noted that the applicant’s program basis document and inspection procedure for the Closed Treated Water Systems program states that the boron thermal regeneration system (BTRS) chilled water system has a water chemistry environment of molybdate with TTA. In contrast, the applicant’s water chemistry monitoring procedure indicates that the BTRS chilled water system is in a nitrite/molybdate chemistry environment, as defined in EPRI Report TR-1007820, “Closed Cooling Water Chemistry Guideline, Revision 1.”

Issue:

It is unclear to the staff which water chemistry control approach is used in the BTRS chilled water system. The staff notes that the improper identification of the water chemistry of the BTRS chill water system may lead to an inadequate inspection sampling of unique combinations of materials and water treatment programs.

Request:

Clarify the water chemistry environment of the BTRS chilled water system and revise the LRA, program basis document, and inspection sampling plan, as necessary.

Callaway Response

The water chemistry treatment program for the Boron Thermal Regeneration System (BTRS) chilled water system is nitrite/molybdate with tolyltriazole. LRA Appendix B2.1.11 has been revised, as shown on LRA Amendment 5 in Enclosure 2 to identify that the water chemistry treatment program for the BTRS chilled water system is nitrite/molybdate with tolyltriazole. LRA Table 3.3.2-10 has been revised, as shown on LRA Amendment 5 in Enclosure 2 to indicate that the internal environment of the components in the BTRS chilled water system is closed cycle cooling water. The Closed Treated Water Systems program basis document and associated draft inspection sampling plan have been revised to identify the water chemistry treatment program for BTRS chilled water system as nitrite/molybdate with tolyltriazole. The Selective Leaching program basis document and associated draft procedure have been revised to indicate that the internal environment of the copper alloy (>15% zinc) is closed cycle cooling water.

Corresponding Amendment Changes

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

RAI B2.1.11-2

Background:

The “detection of aging effects” program element of GALL Report AMP XI.M21A, “Closed Treated Water Systems” states that a representative sample of piping and components is selected based on likelihood of corrosion or cracking and inspected at an interval not to exceed once in 10 years.

The enhancement to LRA Section B2.1.11 states that representative samples of each combination of material and water treatment program will be visually inspected at least every 10 years or opportunistically when consistent with sample requirements. During its audit of the applicant’s onsite documentation, the staff noted that the applicant’s program basis document states that, for each chemical environment (water treatment), a representative sample of component surfaces is disassembled and inspected every 10 years. The basis document also states that the sample size is 20 percent of the components, up to a maximum of 25 for each chemical environment. The document further states that at least two samples of each material are included in the representative sample for each chemical environment.

The applicant’s draft inspection procedure for the Closed Treated Water Systems program states that at least 10 percent of the components for each material-environment combination will be inspected, and that the maximum sample size for each material-environment combination is 10. However, another location in the same procedure states that if the number of inspection opportunities reaches five for any of the material-environment combinations, then the sampling for that material-environment combination is complete.

Issue:

a) The enhancement to the LRA, the LRA basis document, and draft implementing procedure for the inspections in the Closed Treated Water Systems program differ regarding the sampling methodology. Differences include the definition of the sampling population (each material-environment combination or each environment) and the percentage and number of inspections for each population (20 percent with a maximum of 25, 10 percent with a maximum of 10, or a maximum of 5 opportunistic inspections)

   It is unclear to the staff which sampling methodology will be used, and the underlying technical basis for the chosen methodology, for the inspections in the Closed Treated Water Systems program.

b) The LRA and program basis document do not state that inspection locations will be selected based on likelihood of corrosion or cracking. The staff believes that such an inspection methodology is important to ensure that aging can be detected prior to loss of intended function.

Request:

a) State what inspection sampling methodology will be used in the Closed Treated Water Systems program and provide technical justification for the methodology used. Revise the LRA, program basis document, and implementing procedures, as necessary.

b) State whether inspection locations will be selected based on likelihood of corrosion and cracking, or provide technical justification for not doing so.

Callaway Response

a) The Closed Treated Water Systems program basis document identifies a sample size of 20% of the components, up to a maximum of 25 components for each chemical environment with at least two samples of each material to be included in the representative sample for each chemical environment. Inspections will be conducted during each ten year period beginning ten years prior to the entry into the period of extended operation.

The sample requirements in the draft implementing procedure were incorrect. The sample requirements in the draft implementing procedure have been revised to agree with the program basis document.

b) The Closed Treated Water Systems program inspection locations will be selected based on the likelihood of corrosion and cracking. LRA Appendix B2.1.11 and Appendix A Table A4-1, Item 7 have been revised as shown on LRA Amendment 5 in Enclosure 2 to identify that the Closed Treated Water Systems program inspection locations will be selected based on the likelihood of corrosion and cracking.

Corresponding Amendment Changes

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

RAI 3.0.1-1

Background:

GALL Report Section IX.D states that stainless steels are susceptible to SCC when exposed to water environments with temperatures above 60°C (140°F).

LRA Table 3.0-1 states that its water environments encompass the GALL Report defined environments both above and below the SCC threshold. For example, the closed cycle cooling water environment in the LRA encompasses the GALL Report defined environments of closed cycle cooling water and closed cycle cooling water >60°C (>140°F). Also, the secondary water environment in the LRA encompasses the GALL Report defined environments of treated water and treated water >60°C (>140°F).

Issue:

It is unclear to the staff which components in the LRA may be exposed to water temperatures greater than the SCC threshold. Without this information, the staff cannot evaluate whether SCC is being properly managed.

Request:

Identify which in-scope components are exposed to water environments with temperatures greater than the SCC threshold (60°C, 140°F). For any identified items not currently evaluated in the LRA for SCC, add an AMR item to manage this aging effect.

Callaway Response

Stainless steel components exposed to water environments greater than 60°C (140°F) have an aging effect of cracking. The stainless steel components with a water environment and an aging effect of cracking are identified in LRA tables 3.X.2. The following is a list of systems which have stainless steel components exposed to a water environment greater than 60°C (140°F) and the LRA table showing the aging effect of cracking.

Reactor Vessel and Internals (BBVI)	LRA Table 3.1.2-1
Reactor Coolant System (BB)	LRA Table 3.1.2-2
Pressurizer (PZR)	LRA Table 3.1.2-3
Steam Generators (SGR)	LRA Table 3.1.2-4
High Pressure Coolant Injection System (EM)	LRA Table 3.2.2-5
Residual Heat Removal System (EJ)	LRA Table 3.2.2-6
Fuel Pool Cooling and Cleanup System (EC)	LRA Table 3.3.2-2
Nuclear Sampling System (SJ)	LRA Table 3.3.2-9
Chemical and Volume Control System (BG)	LRA Table 3.3.2-10
Standby Diesel Generator Engine System (KJ)	LRA Table 3.3.2-22
Liquid Radwaste System (HB)	LRA Table 3.3.2-24
Plant Heating System (GA)	LRA Table 3.3.2-28
Boron Recycle System (HE)	LRA Table 3.3.2-28
Main Feedwater System (AE)	LRA Table 3.4.2-3

LRA Table 3.3.2-22 has been revised to add AMR lines for the stainless steel components in the standby diesel generator engine system which are susceptible to stress corrosion cracking as shown on LRA Amendment 5 in Enclosure 2.

Corresponding Amendment Changes

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

RAI B2.1.13-1

Background:

GALL Report AMP XI.M26, "Fire Protection," is a fire barrier inspection program that includes aging management of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials. The LRA denotes items with an intended function of fire barrier using an "FB." However, there are AMR items in LRA Table 3.5.2-1 for hatch emergency airlock and hatch personnel airlock exposed to plant indoor air which have an intended function of fire barrier but are not being managed for aging using the Fire Protection program.

Issue:

It is not clear to the staff how components with a fire barrier function are being adequately managed for aging using alternative programs.

Request:

Explain how the items with a fire barrier function that are not being managed for aging using the Fire Protection program are being adequately managed for aging using alternative programs. The explanation should include a comparison of the types of inspections, frequency of inspections, and qualifications of personnel performing the inspections.

Callaway Response

Hatch Emergency Airlock:

FSAR figure 9.5.1-2, Sheet 2, identifies the containment emergency personnel hatch (hatch emergency airlock) as included as part of fire zone RB-2. The containment emergency personnel hatch is discussed in the FSAR, Appendix 9.5B SP – Fire Hazards Analysis, Page 9.5B-189 as a component that provides a means for evacuation. The containment emergency personnel hatch is designated as a fire barrier and is subject to surveillance requirements associated with the Fire Protection program (B2.1.13). As a result, LRA Table 3.5.2-1 has been revised by LRA Amendment 5 in Enclosure 2 to identify that the Fire Protection program (B2.1.13) will also be used to manage the aging of the containment emergency personnel hatch.

Hatch Personnel Airlock:

FSAR figure 9.5.1-2, Sheet 4, identifies the containment personnel hatch (hatch personnel airlock) is adjacent to and extends into the Auxiliary Building. As discussed in the FSAR, Appendix 9.5B SP – Fire Hazards Analysis, Page 9.5B-63, the containment personnel hatch provides a 3-hour-rated fire barrier between fire areas A-20 and RB-10. The containment personnel hatch is designated as a fire barrier and is subject to surveillance requirements associated with the Fire Protection program (B2.1.13). As a result, LRA Table 3.5.2-1 has been revised by LRA Amendment 5 in Enclosure 2 to identify that the Fire Protection program (B2.1.13) will also be used to manage the aging of the containment personnel hatch.

Corresponding Amendment Changes

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

RAI B2.1.13-2

Background:

The "detection of aging effects" program element of GALL Report AMP XI.M26, "Fire Protection," states that visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials are performed by fire protection qualified personnel. LRA Section B2.1.13 states that the Fire Protection program, following enhancement, will be consistent with GALL Report AMP XI.M26. During the audit, the staff noted that procedures QSP-ZZ-65045, "Fire Barrier Seal Visual Inspection," and QSP-ZZ-65046, "Fire Barrier Inspection," state that the personnel performing the inspections are Quality Control Inspectors. The staff also noted that procedure OSP-KC-00015, "Fire Door Inspections," does not state what qualifications are required for personnel who perform the inspections.

The Callaway FSAR-SP, Section 9.5.1.6, and FSAR-SA, Appendix 9.5A, Section A.1 both state that Section 9.5 of the FSAR-SA discusses training for maintaining the competence of the station fire fighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. However, the information regarding training of personnel who maintain and inspect fire protection equipment does not appear to be included in the FSAR-SP or FSAR-SA. RG 1.189, "Fire Protection for Nuclear Power Plants," states that personnel responsible for maintaining and testing fire protection systems should be qualified by training and experience for such work.

Issue:

Neither the FSAR nor the LRA discuss the training and qualifications required for personnel responsible for performing Fire Protection program inspections. It is not clear to the staff whether the personnel who perform inspections as part of the Fire Protection program are properly trained and qualified to perform the inspections, consistent with GALL Report XI.M26.

Request:

Explain the minimum training and qualifications required for personnel who perform Fire Protection program inspections. Explain how only personnel with the required training and experience are assigned to perform Fire Protection program inspections since a fire protection qualification is not used.

Callaway Response

The minimum training requirements for personnel performing inspections are outlined in the Operating Quality Assurance Manual (OQAM) Section 10. The OQAM qualification process is consistent with Regulatory Guide 1.58 – Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (ANSI N45.2.6-1978).

Per Section 10.7 of OQAM, Quality Control inspection personnel or other personnel who perform inspection activities shall be qualified within their respective areas of responsibility. The qualification of QC inspection personnel shall be defined in three levels of capability as described in ANSI N45.2.6. Other personnel performing inspection activities shall have appropriate experience, training, and retraining to assure competence in accordance with ANSI/ANS-3.1 (Selection and Training of Nuclear Power Plant Personnel) and applicable codes and standards.

An inspection personnel qualification program for QC personnel ensures inspection activities are being performed by personnel trained and qualified to a capability necessary for performance of the activity. Procedure QCP-ZZ-01000 (QC Inspector Qualification) describes the qualification process and defines the responsibilities of the QC personnel.

Non-QC level surveillance inspections such as Fire Door Inspections identified in OSP-KC-00015 are performed by operations personnel, who are qualified by a specific watchstation qualification program administered by Training and Operations Line Management.

Corresponding Amendment Changes

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

RAI B2.1.14-1

Background:

The GALL Report AMP XI.M27, "Fire Water System," recommends that sprinklers that have been in place for 50 years be replaced or a representative sample of sprinklers be field service tested at a recognized testing laboratory in accordance with National Fire Protection Association (NFPA) 25, "Inspection Testing and Maintenance of Water-Based Fire Protection Systems." LRA Section B2.1.14, "Fire Water System," states that sprinklers will be replaced prior to 50 years inservice or a representative sample of sprinklers will be tested, with testing repeated every 10 years.

Issue:

The Fire Water System program does not discuss what type of testing will be performed on the sprinklers if they are not replaced prior to reaching 50 years inservice and whether testing will be performed in accordance with NFPA 25. It is unclear to the staff whether sprinkler field service testing will be performed at a recognized testing laboratory in accordance with NFPA 25.

Request:

Clarify whether sprinkler field service testing will be performed at a recognized testing laboratory in accordance with NFPA 25. If sprinkler field service testing will not be performed at a recognized testing laboratory in accordance with NFPA 25, explain the testing that will be performed, including test methods and acceptance criteria, and how this testing satisfies the guidance in NFPA 25.

Callaway Response

LRA Appendix A1.14, LRA Appendix B2.1.14, and LRA Table A4-1, Item 10, were revised to be consistent with NFPA 25 and require that prior to 50 years in service, representative samples of sprinkler heads will be submitted for field-service testing by a recognized testing laboratory. Additional representative samples of sprinkler heads will be field-service tested at 10 year intervals following the initial field-service testing. LRA Appendix A1.14, LRA Appendix B2.1.14, and LRA Table A4-1 item 10 have been revised by LRA Amendment 5 in Enclosure 2 to identify sprinkler head testing requirements.

Corresponding Amendment Changes

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

Corresponding Amendment Changes

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

RAI B2.1.14-3

Background:

The “detection of aging effects” program element of GALL Report AMP XI.M27, “Fire Water System,” recommends that fire hoses be hydrostatically tested annually in accordance with NFPA codes and standards. LRA Section B2.1.14, “Fire Water System,” states an exception to GALL Report AMP XI.M27 to perform hydrostatic hose testing for hose stations that are more than five years old on a three year frequency. During the audit, the staff noted that hydrostatic testing has not been performed since 2007. The staff also noted that CAR 201110777 documents failure of a fire hose when it was charged during fire brigade training in 2011. The hose had last been tested in 2007.

Issue:

It is not clear to the staff why the existing frequency of three years is acceptable to ensure degradation of fire hose is identified prior to loss of intended function.

Request:

Provide justification for why the existing fire hose hydrostatic testing frequency is adequate to identify degradation of fire hose prior to loss of intended function.

Callaway Response

The Fire Water System program categorizes fire hoses as “fire brigade hose” and “interior fire hose (fire hose station).” Surveillance and testing frequencies for each type of fire hose are different and therefore discussed separately.

Interior Fire Hose for Fire Hose Stations:

The Fire Water System program requires hydrostatic testing of interior fire hose for fire hose stations five years from installation and every 3 years thereafter.

Fire Brigade Hose:

The hydrostatic testing frequency of fire brigade hose is being revised and will be performed annually. The Fire Water System program will be enhanced to include the annual hydrostatic testing frequency requirement for fire brigade hose. LRA Appendix B2.1.14 and LRA Appendix A4-1 item 10 have been revised, as shown on Amendment 5 in Enclosure 2 to include an enhancement for an annual hydrostatic test frequency for fire brigade hose.

Corresponding Amendment Changes

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

RAI B2.1.14-4

Background:

The “detection of aging effects” program element of GALL Report AMP XI.M27, “Fire Water System,” recommends that fire hydrants be flow tested annually in accordance with NFPA 25. LRA Section B2.1.14, “Fire Water System,” states an exception to GALL Report AMP XI.M27 to perform fire hydrant flow tests every three years. During the audit, the staff reviewed the results of the recent performances of the fire hydrant flow tests. The testing performed in 2011 indicated that approximately 25 percent of the hydrants tested failed to drain in the required time frame. The testing performed in 2007 indicated that approximately 20 percent of the hydrants tested failed to drain properly, and testing performed in 2005 indicated that approximately 50 percent of the hydrants tested failed to drain as required.

Issue:

It is not clear to the staff why the existing fire hydrant flow testing frequency of three years is acceptable to identify degradation prior to loss of intended function given that hydrant flow testing performed in 2005, 2007, and 2011 resulted in 20-50 percent of the hydrants failing to drain in the required time.

Request:

Provide justification for why the existing hydrant flow testing frequency is adequate to identify degradation of the fire hydrants prior to loss of intended function.

Callaway Response

The Fire Water System program will be enhanced to include annual hydrant flow testing consistent with NFPA 25 requirements and remove the element four exception for three-year hydrant flow testing. LRA Appendix B2.1.14 and Table A4-1 item 10 have been revised, as shown on Amendment 5 in Enclosure 2 to include an enhancement for an annual hydrant flow testing. LRA Appendix B2.1.14 has been revised, as shown on Amendment 5 in Enclosure 2, to delete the exception in element four for three-year hydrant flow testing.

Corresponding Amendment Changes

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

RAI B2.1.14-5

Background:

GALL Report AMP XI.M27, "Fire Water System," manages aging for components exposed to fire water to ensure degradation is detected prior to loss of intended function. GALL Report AMP XI.M27 includes system flow testing and pipe wall thickness evaluations to manage aging. LRA Section B2.1.14, "Fire Water System," states that flow testing is performed every three years and pipe wall thickness examinations or internal inspections will be performed prior to the period of extended operation and every 10 years.

In the "operating experience" program element, the LRA includes an operating experience example which states that there was a leak in the fire water system in 2005 identified by excessive jockey pump run times. CAR 200510105 clarifies that the leak was on buried piping on an isolable branch. The LRA includes another operating experience example in which a low cleanliness factor was identified during system flow testing in 2006. Chemical cleaning was performed on the fire water system to improve the cleanliness factor. However, after chemical cleaning, five leaks developed which were subsequently repaired. During the audit, the staff noted that microbiologically influenced corrosion (MIC) contributed to the low cleanliness factor and leakage; and that subsequent to the chemical cleaning, additional leaks have occurred. The staff also noted that system flow testing performed in 2011 identified a low cleanliness factor again and that compensatory measures were required to maintain system intended function.

Issue:

The fire water system degraded from a clean system in 2006 to a degraded system in 2011 in which compensatory measures were required to maintain system intended function. System flow testing performed on a three year frequency and pipe wall thickness evaluations performed on a 10 year frequency do not appear to be adequate to ensure aging is identified prior to loss of intended function throughout the period of extended operation. It is not clear to the staff how aging of the fire water system will be adequately managed during the period of extended operation such that loss of intended function of the fire water piping does not occur.

Request:

a) For the past 10 years, list each instance of internal or external degradation of the fire protection piping which resulted in either thru-wall or significant penetration of the pipe wall (e.g., approaching pipe minimum wall thickness). Include out-of-scope piping instances where the environment is similar to that of in-scope piping. Include the following:

   i. date discovered,
   ii. description of location of the degradation (e.g., internal, external, aboveground, buried),
   iii. probable cause, if known (e.g., MIC, coating degradation leading to general or pitting corrosion),
   iv. configuration of the degradation (e.g., plug type, planar), and
   v. extent of degradation, or results of extent of condition review, if conducted

b) Describe the results of general internal and external observations of the condition of the piping and coatings that have been conducted for the past 10 years.

c) Given the above, project the condition of the internal and external surfaces of the fire protection system in-scope piping through the end of the period of extended operation. For example, extent of MIC sites, condition of external coatings, general pipe wall thickness.

d) State the basis for why the configuration of the in-scope fire protection system will have sufficient structural integrity to meet all design loads throughout the period of extended operation. Include consideration of multiple flaws located in a configuration such that they cannot be considered as independent flaws.

e) State how the inspections of the fire water system will be augmented to ensure that the assumptions used in the response to “d” above, will be met throughout the period of extended operation.

Callaway Response

a) A plant Operating Experience (OE) search was performed for instances of Inner Diameter (ID) and Outer Diameter (OD) degradation of the fire protection piping which resulted in either through-wall or significant penetration of the pipe wall, as well as other relevant conditions, between the years 2001 and 2012. The results are summarized in Table 1-Leak History (*Refer to page 30 and 31 of this enclosure*).

b) As documented in Table 1-Leak History, internal aging, external aging, and non-aging effects were identified in Fire Protection System (FPS) piping. The primary internal aging effect is fouling due to corrosion products. External aging effects include coating degradation and loss of material due to pitting. Non-aging related effects include improper installation and other human performance issues.

<u>Internal Aging Effects</u>

There are no failures of the FPS since 2001 that are attributed to internal aging effects. Prior to chemical cleaning in 2006, the system was susceptible to fouling due to non microbial corrosion products and tuberculation generated within the system itself. This fouling impacted flow rates through the system piping, as evidenced in the failed 2004 Fire Main Flow Test. The buried portions of the main fire loop piping were chemically cleaned in August 2006 to remove accumulated corrosion products on the inside diameter. The chemical cleaning removed corrosion products from the interior pipe wall, revealing a number of leaks. These leaks were exclusively in piping that is not within the scope of license renewal, such as the fire protection piping routed to the Training Center which was subsequently replaced with High Density Polyethylene (HDPE) in 2007. Corrosion products that were freed during the chemical cleaning were observed to settle out in branch lines of the fire protection system that were normally stagnant. In the weeks following the chemical cleaning, instances of small diameter line clogging and valve leakby were documented and attributed to the settling of corrosion products.

To mitigate internal aging mechanisms that are normally anticipated within this relatively stagnant, raw water system, an anti-scalant (HEDP), a biopenetrant, and a biostat (BULAB 6002) are added to the Fire Water Storage Tanks on a weekly basis. These chemical additions are also performed yearly in conjunction with an annual fire main flush, which ensures that treatment reaches all possible areas of the FPS. Water treatment of the Fire Protection System was initiated in October of 1996. Prior to this date, the water was untreated.

An opportunistic internal visual inspection of FPS pipe in the turbine building was performed in June 2012 in seven different locations. These inspections identified no signs of microbial infestation in the system, indicating effective water treatment, and no wall loss was noted. MIC culture samples were also collected for microbial analysis and confirmatory testing is ongoing.

External Aging Effects

External aging effects, such as wall loss and pitting due to degraded coatings and poor cathodic protection, have attributed to leaks within the FPS. Highly localized damage was identified in areas of coating failure. In these occurrences, the degradation was exacerbated by ineffective cathodic protection in the location of the coating failure. A Close Interval Survey (CIS) was performed on the cathodic protection of the buried FPS in 2008. This survey concluded that FPS piping was not sufficiently protected. Implementation of the Buried and Underground Piping and Tanks Aging Management Program will include trending and monitoring of cathodic protection to ensure future effectiveness. (Callaway's response to RAI B2.1.25-3 includes revision to LRA Appendix A1.25 and LRA Appendix B2.1.25, as shown on LRA Amendment 5 in Enclosure 2, to discuss the cathodic protection system.)

Non Aging Related Failures

Non-aging related issues, such as human performance, were also attributed to failures. Two instances were identified where HDPE piping near the Training Center was improperly installed, which resulted in leaks. Additionally, human performance issues are a factor in the multiple failures of the Fire Main Flow Tests. In 2004, failure of the Fire Main Flow Test was attributed to accumulated corrosion products. As corrective action, the system was chemically cleaned in 2006 and subsequently met the acceptance criteria. The system again failed the Fire Main Flow Test in 2009. In response, the testing methodology and calculation of acceptance criteria were examined. It was determined that a combination of factors had not been properly calculated, including gauge elevation, rounding error, and rerouting of fire main piping. The calculation and flow test procedure were revised to account for these factors, and it was determined that the Fire Main Flow Test acceptance criteria had been met satisfactorily. The system failed the flow test a third time in 2011. The presence of corrosion products was not eliminated as a cause; however, portions of the supporting calculation were determined to be unnecessarily conservative. The calculation that predicted the pressure drop from the fire pumps to the sprinkler systems was revised to remove conservatism regarding how much additional flow was assumed to hose stations or yard hydrants coincident with sprinkler demand. By reducing the coincidental fire water flow to the licensing basis value, the pressure drop that must be overcome by the fire water pumps is reduced, increasing pump performance and system cleanliness margin. The calculation used to determine pipe cleanliness also was rewritten and incorporated changes such as taking credit for actual fire pump performance. The test procedure was updated to reflect the revised criteria. When the revised acceptance criteria were applied, the Fire Main Flow Test results were satisfactory. Cleanliness of the piping continues to be trended and monitored by engineering. Additionally, the frequency of the Fire Main Flow Test is being reassessed to determine if the current performance frequency is sufficient to proactively identify degrading flow conditions.

c) Given the operating experience described in the preceding sections, the internal and external aging effects of buried and above ground fire protection system piping are being adequately managed through existing trending, monitoring and inspection activities.

Degraded conditions that are identified as a result of these activities are entered into the Corrective Action Program so that appropriate corrective actions can be taken.

To project the condition of the internal and external surfaces of the in-scope fire protection piping through the end of the period of extended operation, focus on specific aging mechanisms such as microbial corrosion, coatings and pipe wall thickness must be addressed:

- To address the potential for microbial corrosion, opportunistic inspections are performed and MIC samples are obtained for evaluation. If active MIC colonies are discovered, then corrective action documents are generated to develop plans to inspect or mitigate the effects. To date, no MIC issues have been identified that impact the structural integrity of the FPS piping.

- The FPS buried piping is externally coated with coal tar enamel and wrapped with bonded asbestos felt and kraft paper. The coal tar enamel that is on the FPS can be expected to have a service life ranging from 15 to 50 years depending on soil environment. Plant operating experience reflects that some of the coating for buried fire protection system piping is nearing the end of its service life. The degraded coatings that were found were near the Training Center where installation processes, oversight and standards were not as strict as they would be within the power block. The second line of defense is the cathodic protection system, which is applied to prevent corrosion at holidays, damaged or degraded areas in the coating. Annual pipe-to-soil cathodic protection surveys are conducted to measure the level of protection provided by the system and bimonthly rectifier checks are performed to ensure rectifiers are operational. As part of the Buried and Underground Piping and Tanks program, as previously noted, trending and monitoring of cathodic protection will be included to ensure future effectiveness.

- A license renewal enhancement to the Fire Protection program will require a sampling plan to be utilized for non-destructive testing to determine general wall thickness. Locations are selected based on susceptible locations and information obtained from opportunistic inspections and chemistry sampling.

These activities and use of the Corrective Action Program will ensure that the fire protection system piping is adequately managed for aging throughout the period of extended operation such that loss of intended function does not occur.

d) Although operating experience has not demonstrated any failures due to internal aging mechanisms, Callaway has programs in place to monitor the degradation of internal surfaces of FPS piping. Per the Raw Water Systems Control Program Chemistry performs MIC culture samples when FPS piping is open for maintenance or is accessible. If active colonies are discovered, a CAR is written, and plans for inspection/mitigation are developed. Per the Raw Water Predictive Maintenance Program, Engineering performs inspections to ensure the structural integrity of the piping. During FPS maintenance in 2012, engineering performed opportunistic internal visual inspections in seven locations on FPS piping located in the Turbine Building and Chemistry performed MIC culture sampling. No adverse conditions were identified as a result of engineering and chemistry evaluations. An additional opportunistic inspection of the aboveground piping adjoining one of the diesel driven fire pumps is currently planned. The Raw Water Systems Control Program and excavation process notify chemistry and engineering personnel to perform these opportunistic inspections.

Callaway's current NEI 09-14 Buried Piping Program manages the degradation of external surfaces of FPS piping. The current program, augmented with the requirements in license renewal, will verify the structural integrity of underground FPS piping through periodic and opportunistic inspections. During FPS hydrant maintenance in 2011, engineering performed an opportunistic visual inspection of the external and internal surfaces of excavated piping. Visual inspection of FPS coatings identified no physical damage or breaks in the coating. The internal inspection noted no signs of microbial infestation.

These activities will ensure that the in-scope fire protection system piping will have sufficient structural integrity to meet all design loads throughout the period of extended operation.

e) The Fire Protection program will be enhanced to require a sampling plan to be utilized for non-destructive testing to determine general wall thickness. Locations are selected based on susceptible locations and information obtained from opportunistic inspections and chemistry sampling. The Buried and Underground Piping and Tanks program will include trending and monitoring of cathodic protection to ensure future effectiveness. These enhancements will ensure the integrity of the Fire Protection System through the end of the period of extended operation.

Corresponding Amendment Changes

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

Table 1 - Leak History

Date Discovered	Component	Internal/External	Above/ Buried	In/Out of Scope	Event	Apparent Cause	Configuration of Degradation	Extent of Degradation (EOC)	CARS
09/13/2004	Pipe	Unknown	Buried	Out of scope	Leak	Unknown - likely corrosion of abandoned in place piping or poor isolation	Unknown - Pipe was abandoned	Abandoned FPS piping outside of powerblock	200407150
10/29/2004	Pipe	Internal	Buried	In scope	Failure of flow test	Build up of deposits (not MIC)	Non-planar flaw	Main Fire Loop	200408232
12/13/2005	Pipe	Unknown	Buried	Out of scope	Leak	Likely failure of bell and spigot joint	N/A - joint failure	Original construction fire loop (not Main Fire Loop)	200510105
07/26/2006	Pipe	External	Buried	Out of scope	Leak	Coating Damage; ineffective cathodic protection	Non-planar flaw	FPS piping with coating	200605969
07/27/2006	Pipe	External	Buried	In scope	Leak	Coating Damage; ineffective cathodic protection	Non-planar flaw	FPS piping with coating	200606030
08/22/2006	Pipe	Internal	Above ground	Out of scope	No failure - blocked strainer observed	Corrosion products (hematite) from chemical cleaning clogged small diameter alarm test piping	N/A	FPS to Stores 1	200606874
8/23/2006	Pipe	Unknown	Buried	Out of scope	Leak	Unknown - likely coating damage. Pipe was abandoned in place and new HDPE pipe routed	Unknown - Pipe was abandoned	FPS to Training Center (non-powerblock)	200606913
09/18/2006	Pipe	Internal	N/A	In scope	No failure - valve leakby observed	Settling of corrosion products (hematite) from chemical cleaning in normally stagnant piping	N/A	FPS piping branches from Main Fire Loop	200607707
09/19/2006	Pipe	External	Buried	In scope	No failure - Pitting observed	Coating Damage; previously ineffective cathodic protection	Non-planar flaw	FPS piping with coating	200607749

Table 1 - Leak History (cont'd)

Date Discovered	Component	Internal/External	Above/ Buried	In/Out of Scope	Event	Apparent Cause	Configuration of Degradation	Extent of Degradation (EOC)	CARS
08/02/2007	Pipe	Unknown	Buried	Out of scope	Leak	Unknown - likely coating damage. Pipe was abandoned in place and new HDPE pipe routed	Unknown - Pipe was abandoned	FPS to Training Center (non-powerblock)	200707175
12/10/2007	Pipe	Unknown	Buried	In scope	Leak	Unknown - this branch from Main Fire Loop to Auxiliary Building subsequently isolated	Unknown - Pipe was isolated	Main Fire Loop	200711546
03/12/2008	Pipe	N/A	Buried	Out of scope	Leak	Improper installation	N/A - poor fusion	Buried HDPE FPS piping	200801913
11/18/2009	Pipe	N/A	Buried	In scope	Failure of flow test	Inaccurate calculation	N/A	Main Fire Loop	200909578
04/11/2011	Pipe	N/A	Buried	In Scope	Failure of flow test	Inaccurate calculation	N/A	Main Fire Loop	201102974
10/03/2011	Pipe	N/A	Buried	Out of scope	Leak	Improper installation	N/A - poor fusion	Buried HDPE FPS piping	201107928

RAI B2.1.15-1

Background:

The "preventive actions" program element of the Aboveground Metallic Tanks program states that there are no sealants or caulking applied at the external interface between the bottoms of the condensate storage tank (CST) and refueling water storage tank (RWST) and their concrete foundations. The GALL Report AMP recommends that sealant or caulking be applied at the external surface of the interface joint to minimize the amount of water penetrating the interface, which could lead to corrosion of the tank bottom.

Issue:

The above statements are not consistent, and the applicant did not identify this as an exception and provide a justification for not meeting the recommendation. Given that this preventive measure is not met, it is not clear to the staff why the number of tank bottom volumetric inspections to be conducted (i.e., one within five years of entering the period of extended operation and whenever tank is drained) is adequate to ensure that the tank's intended function(s) will be met during the period of extended operation.

Request:

State the basis for why the proposed inspection schedule of CST and RWST tank bottom is sufficient to ensure that the tanks will meet their intended function(s) during the period of extended operation.

Callaway Response

The tank foundations for the condensate storage tank (CST) and refueling water storage tank (RWST) are designed utilizing a radial slope. The high point of the foundation is located at the tank centerline allowing collected liquid to flow down and away from the base of the tanks. Caulking and/or sealant at the external interface of the tank bottoms and their foundations would impede this design by preventing water from flowing outward, trapping water between the foundations. To ensure the tank bottoms' thickness is maintained within specifications, the tank bottoms will be volumetrically inspected once within the five years of entering the period of extended operation and whenever the tanks are drained.

The design of the CST and RWST foundations combined with the inspection frequency will provide reasonable assurance that degradation is detected and corrective action taken prior to the loss of intended function.

Corresponding Amendment Changes

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

RAI B.2.1.15-2

Background:

The “preventive actions” program element of the Aboveground Metallic Tanks program states:

- the stainless steel CST does not have a protective coating; the insulation materials have a documented evaluation demonstrating that there are not any harmful substances which could leach onto the tank surface; and, the insulation has a protective aluminum jacket with overlapping seams. In contrast to this statement, LRA Table 3.4.2-6, Insulation, plant-specific note 3, in pertinent part, states, “[t]he dome of the stainless steel tank is prepped with a low halogen (<200 ppm) primer prior to the application of the foam urethane.”
- the stainless steel RWST does not have a protective coating, and the insulation has a protective aluminum jacket with overlapping seams,

During the staff’s walkdown of the structure that partially encloses the CST, water stains were observed on the side of the tank where insulation is not installed.

The GALL Report AMP recommends that, “[i]n accordance with industry practice, tanks may be coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure.”

Issue:

The staff has the following concerns/questions:

- The staff lacks sufficient information related to the potential for chemical compounds in the cooling tower water or soil (which could become airborne), if present, to migrate to the tank’s external surface and cause cracking, pitting, or crevice corrosion of the stainless steel surface.
- The applicant has not provided information related to whether the insulation on the RWST contains harmful substances that could leach onto the tank surface and cause corrosion.
- Given the inconsistency between the program and LRA Table 3.4.2-6 in regard to protective coatings on the CST, the staff questions if coatings are applied on the entire or portions of the CST and RWST external surfaces. In addition, if the coatings are credited for purposes of license renewal, whether holiday testing was conducted during initial application of the coating and whether the coatings will be inspected during the period of extended operation.
- It is not clear that insulation jacketing will prevent water intrusion into the tank insulation and then onto the tank surface.

Request:

a) State whether there is or could be the potential for chemical compounds in the cooling tower water, soil, or other sources to migrate to the CST or RWST insulation jacketing or tank external surfaces.

b) State whether the RWST insulation contains any harmful substances which could leach onto the tank surface. If so, state the basis for why the currently proposed inspections are capable of detecting cracking, pitting, or crevice corrosion on the external surfaces of the tank.

c) State whether and what portions of the CST is coated and, if applied and not the same as documented in LRA Table 3.4.2-6, Insulation, plant-specific note 3, state the coating composition.

d) If the tank external surface coating has been credited for purposes of license renewal (e.g., limit the potential for corrosion of external surfaces, allow less inspections of external surfaces of the tank), state whether holiday testing was conducted during initial application of the coating and state the basis for why no coating inspections are proposed as part of the program unless opportunistically inspected during insulation removal. If the tank external surface coating has not been credited for purposes of license renewal, state why the proposed inspections are adequate in light of coatings not being available as a preventive measure.

e) Given the evidence of water stains on the side of the CST where insulation is not installed, state the basis for why it can be concluded that the CST and RWST insulation jacketing will prevent water intrusion into the tank insulation and then onto the tank surface.

f) If the cooling tower water is not currently treated, or is currently treated with biocides or other chemicals which do not contain harmful chemical compounds, and the basis for any of the above questions is that harmful compounds cannot reach the external surfaces of the CST and RWST:

   i. revise LRA Section A1.15 to state that chemical treatments of cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tank, and

   ii. propose a schedule for periodic site soil samples that will demonstrate that harmful compounds are not accumulating on the soil surface.

Callaway Response

a) There has been no operating experience indicating negative effects of chemical compounds in the cooling tower water, soil, or other sources on the surfaces of the CST or RWST. The range of cooling water chemicals includes biocides, bleach, coagulant aids, cationic polymers, bromine, HEDP (hydoxyethylidine diphosphonic acid), pyrophosphate, sodium tolytriazole, biopenetrant, and sulfuric acid.

b) The RWST is insulated with calcium silicate insulation that is covered with an aluminum jacket. FSAR-SP Table 6.1-6 describes how the recommendations of Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel, are met for the Callaway plant. Callaway insulation specifications comply with Regulatory Guide 1.36 requirements to protect stainless steel components against stress corrosion cracking that could be caused by the leaching of contaminants such as chloride and fluoride from insulation. Only insulation materials yielding low leachable chloride and low fluoride concentrations, and silicate to inhibit external stress corrosion cracking of austenitic stainless steel are used on austenitic stainless steel reactor plant components.

c) The dome exterior of the CST is coated with a low halogen (<200 ppm) primer. The next layer of the CST dome is urethane foam insulation. The urethane foam insulation cover layer of the CST dome is an acrylic rubber sealant coating providing protection from UV radiation. The application of the acrylic rubber sealant and urethane foam insulation is consistent with Plant-Specific Note 3 of Table 3.4.2-6.

   The vertical tank exterior wall is not coated but is insulated with foamglass insulation, which is covered by aluminum jacketing with overlapping seams. The tank exterior sides are insulated with foam glass from the ground elevation to the interface at the dome.

d) The urethane foam insulation that is installed on the dome of the CST is coated with an acrylic rubber sealant, as described in response part c). The CST dome external metallic surface coating is a primer as described in response part c). The CST dome external metallic surface primer does not have an intended function and is not within the scope of license renewal. The CST dome external metallic surface primer is not credited as a preventative measure. The CST acrylic rubber sealant is credited as preventative measure for the CST urethane foam insulation and CST metallic surface. The Aboveground Metallic Tanks program (B2.1.15) manages cracking, blistering, and change in color of the acrylic/urethane insulation on the CST.

e) The water stains on the CST were due to leakage from the old CST pipehouse roof. In 2011 the roof covering the CST pipehouse was replaced in order to provide a better seal between the CST pipehouse and CST tank insulation thus sheltering and protecting the uninsulated portion of the CST.

   The Structures Monitoring program (B2.1.31) manages aging of the CST pipehouse (and associated roof) to maintain its intended function of sheltering and protecting the uninsulated portion of the CST and components within the CST pipehouse.

f) Aging of tank external surfaces due to cooling tower water and soil contaminates:

   i. LRA Appendix A1.15 has been revised, as shown on Amendment 5 in Enclosure 2 to state that the chemical treatments of cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks.

   ii. Within five years of entering the period of extended operation, a one-time soil surface sample near the CST and RWST will be performed. The soil surface sample will be evaluated to ensure that chlorides or other aggressive cooling tower water treatment chemicals are not creating an aggressive environment that would degrade the CST, RWST, or their insulation jacketing.

      LRA Appendix A1.15 and LRA Appendix B2.1.15 have been revised, as shown in LRA Amendment 5, to perform the one-time soil sample.

Corresponding Amendment Changes

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

RAI B2.1.15-3

Background:

The “detection of aging effects” program element of the Aboveground Metallic Tanks program states that visual inspections of the exterior surfaces of the CST and RWST are conducted when the surface is accessible. It also states that for inaccessible exterior tank surfaces, the program will sample wall thickness to ensure that the tank bottom and tank wall sections with insulated outer surfaces are not losing material or cracking. It further states that thickness measurements will be conducted once within five years of entering the period of extended operation and whenever the tank is drained, and at least one measurement per square yard of tank surface will be performed. GALL Report AMP XI.M29, Aboveground Metallic Tanks, recommends that external surfaces of the tank be inspected on a refueling outage interval.

Issue:

The staff questions whether obtaining one thickness data point per square yard of tank surface is sufficient to detect pitting, crevice corrosion, and cracking. Alternatively, if the quantity of inspection points is not changed, the staff questions whether the inspection frequency is sufficient. The staff also questions how a tank wall thickness measurement will also be capable of detecting cracking. The staff further questions what percent of opportunistically removed insulation would be deemed sufficient to not conduct the internal volumetric exams.

Request:

a) State how obtaining one thickness data point per square yard of tank surface is sufficient to detect pitting, crevice corrosion, and cracking once within five years of entering the period of extended operation and whenever the tank is drained, given that the GALL Report AMP XI.M29 is based on inspections of 100 percent of the external surface of a tank on a refueling outage interval.

b) State what wall thickness measurement technique will be used that is capable of detecting wall thickness and cracks.

c) State what percentage of opportunistically removed insulation would be deemed sufficient to not conduct the internal volumetric exams, including whether removal of insulation in one quadrant of the tank would be considered adequate for the entire tank’s circumference.

Callaway Response

a) Instead of inspecting the internal surface of the tank walls, only the external surface of the tank wall will be inspected. The inspection of the tank wall external surface prior to entering the period of extended operation will include locations where the insulation will be removed to demonstrate that the insulating materials are effective in preventing moisture intrusion to the tank surface. External wall surface inspection will require insulation to be removed on 25 locations on the tank external walls to allow inspection for loss of material and cracking. At least ten of the 25 locations will be near the base of the tank wall. Each location will measure approximately one square foot in area.

The tank bottom internal surface will be examined by measuring thickness along 12-inch wide bands of the bottom. The tank thickness measurements will be performed once within the five years of entering the period of extended operation and whenever the tank is drained.

b) Cracking will be detected using a surface examination technique from the tank external surface after insulation has been removed. If cracking is detected, the corrective action program will be used to document and evaluate the aging.

c) Removal of the insulation at a minimum of 25 locations, each exposing approximately one square foot of tank surface will be sufficient to demonstrate the effectiveness of the insulation as an aging management preventative measure. The inspection population will include at least ten locations located near the base of the tank wall around the perimeter where exposure to an aggressive outdoor air environment is most likely to occur.

Corresponding Amendment Changes

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

RAI B2.1.15-4

Background:

The “operating experience” program element of the Aboveground Metallic Tanks program, LRA Section B2.1.15, and the staff’s independent review of CARs and work orders demonstrate that multiple inspections of the internal surfaces of the Fire Water Storage Tanks (FWST), spanning 2007 through 2011, have revealed blistering and delamination of coatings. Work orders documented that these defects were not all repaired prior to returning the tanks to service. The work orders document that the acceptance of the as-found defects that were not repaired was based on internal cathodic protection of the tank preventing corrosion of exposed metal surfaces.

Issue:

Neither the LRA AMP nor FSAR Supplement state that the cathodic protection system is credited as a preventive measure to account for the plant-specific operating experience. In addition, the staff lacks sufficient information to conclude that the delaminating coatings would not block downstream components either based on current levels of delamination or those that could occur in the period of extended operation.

Request:

a) State the basis for why blistering and delamination of coatings will not occur during the period of extended operation despite the current trend of plant-specific operating experience. Alternatively, revise the program and LRA Section A1.15, FSAR Supplement to credit the FWST internal cathodic protection system as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks.

b) State the basis for why delamination of coatings will not prevent downstream in-scope components from being able to perform their intended function(s) during the period of extended operation, including consideration of the size of delaminations that could occur during the period of extended operation.

Callaway Response

a) Blistering and delamination will be corrected prior to the period of extended operation through the application of a new coating. This new coating will be applied prior to the period of extended operation. Additionally, the FWST internal cathodic protection system has been credited as a preventative measure to prevent corrosion on exposed bare metal as-left surfaces of the FWST.

   LRA Appendix A1.15 has been revised, as shown on Amendment 5 in Enclosure 2 to credit the FWST internal cathodic protection system as a preventative measure to prevent corrosion on exposed bare metal as-left surfaces of the FWST. LRA Appendix A1.14, Appendix B2.1.14 and LRA Table A4-1 item 10 have been revised, as shown on Amendment 5 in Enclosure 2 to require recoating of the FWSTs.

b) Minor delaminations have been observed on the FWSTs. The FWSTs are cleaned and inspected on an alternating refueling outage frequency and will be recoated prior to the period of extended operation to remove the coating delaminations and prevent them from becoming an impact on the intended function(s) of downstream components. In addition, the outlet of each FWST is identical and consists of a 14 inch pipe that

extends 3 feet inside the tank and ends in a 90 degree radius elbow turned downward ending 6 inches above the bottom of the tank. In the event of delamination, this geometry would preclude any large pieces of coating from entering the outlet of the tank and affecting downstream equipment.

LRA Appendix B2.1.14 and LRA Table A4-1 item 10 have been revised, as shown on Amendment 5 in Enclosure 2 to require recoating of the FWSTs.

Corresponding Amendment Changes

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

RAI B2.1.16-1

Background:

Element 2, "preventive actions," of the GALL Report AMP XI.M30, "Fuel Oil Chemistry," states that periodic cleaning of a tank allows the removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Although periodic draining of water is incorporated into the applicant's Fuel Oil Chemistry Program, it appears that the applicant takes an exception to the GALL Report as the program does not state that the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank will be cleaned periodically as recommended by the GALL Report.

AMP XI.M30, element 4, "detection of aging effects," recommends that at least once during the 10-year period prior to the period of extended operation, each diesel fuel tank is drained and cleaned, the internal surfaces are visually inspected (if physically possible) and volumetrically inspected if evidence of degradation is observed during visual inspection, or if visual inspection is not available. The LRA states an enhancement to perform volumetric examinations on the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank within the 10-year period prior to the period of extended operation and at least once every 10 years after entering the period of extended operation.

Issue:

Periodic cleaning of a tank is an effective measure to mitigate corrosion. The staff recognizes that performing a periodic volumetric examination could identify if corrosion is occurring in the fuel oil tank.

Request:

State how the volumetric examination, which will be conducted every 10 years, will be sufficient to ensure that the intended function of the tanks will be maintained in lieu of not performing periodic tank cleanings that will mitigate any corrosion that may occur. Alternatively describe the actions that the plant will perform to prevent or mitigate corrosion of the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank and the basis for how these actions will be effective.

Callaway Response

The diesel fire pump fuel oil day tanks are aboveground tanks each with a capacity of 250 gallons. These tanks have no access to the internal surface other than a six inch diameter pipe and several piping connections of two inches or less in diameter. The security diesel generator fuel oil day tank is also an aboveground tank with a capacity of 250 gallons. The security diesel generator fuel oil day tank has no access to the internal surface other than the one-inch diameter holes for engine suction and return, vent, overflow, and inspection. Due to the limited access of their design, draining, cleaning and visual inspection of the internal surface of the security diesel generator fuel oil day tank and diesel fire pump fuel oil day tanks is not physically possible.

Although the internal surface of these tanks cannot be cleaned, other measures are taken to mitigate corrosion. Water is periodically removed from the bottom of these tanks. Minimizing the exposure to water of tank interior surfaces reduces the likelihood of corrosion, and eliminates the environment for microbiological organisms. The tanks will be

periodically sampled to determine water and sediment, particulate, and microbial activity concentrations. If periodic tests indicate the presence of biological activity, a biocide is added to the tanks. New fuel oil receipt sampling will also be performed for water and sediment prior to introduction of the new fuel oil into the tanks.

Although volumetric examinations will not mitigate corrosion, they identify loss of material associated with corrosion. If loss of material is found during an examination, it will be addressed by the corrective action program.

Corresponding Amendment Changes

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

RAI B2.1.16-2

Background:

The applicant provided the following operational experience:

> During Refuel 17 (Spring 2010), as part of the 10-year cleaning and inspection of the emergency fuel oil system storage tank TJE01A, the condition of the internal coating was inspected and determined to be in acceptable condition. No debris, sludge, or bare metal areas were identified during the inspection. The coal tar epoxy coating was in good condition; however, coating blisters were identified in various places. An engineering evaluation determined the identified blistering was acceptable since all instances were less than nickel size. No issue with the coatings has been documented in any of the previous inspections. The procedure requiring the condition of each tank coating to be documented was enhanced to require inclusion of pictures of the internal coating condition and additional details regarding tank internal coating cleanliness, coating color, coating uniformity, and general tank condition.

Issue:

Given that the engineering evaluation described in the operating experience did not state the potential corrosion rate if the blisters were to open up, it is not clear to the staff that the tank would be capable of performing its intended function(s) should further degradation of the coatings occur between inspections.

Request:

State the corrosion rate and minimum design wall thickness of the fuel oil system storage tank should one of the blisters open up, exposing the fuel oil in the tank to the bare metal material of the tank. Additionally, provide an evaluation of the adequacy of the 10 year inspection interval based on the evaluation of the corrosion rate.

Callaway Response

Using the NACE Standard RP0502-2002 default corrosion rate of 16mpy over the 10 year interval, as a bounding scenario, only 0.16 inches of wall thickness would be lost. Using a minimum plate thickness of .875 inches, this would result in a final thickness of 0.715 inches which is significantly greater than the minimum requirements of 0.1159 inches for the shell and 0.2771 inches for the head.

There has been no plant operating experience regarding water found in the emergency diesel fuel oil storage tank. This record of good chemistry control, plus the preventive measure of adding a biocide to the fuel oil, ensures that even if there was a failure of the internal coating, the environment needed for corrosion to occur would not exist. If the monthly fuel oil sampling results start to indicate a trend of water or corrosion products found in the oil, additional corrective actions would be evaluated.

Corresponding Amendment Changes

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

RAI B2.1.19-1

Background:

In Section B2.1.19 of Appendix B to the LRA, the applicant took an exception to GALL Report AMP XI.M33 for buried gray cast iron components, stating that these components do not need to be inspected for selective leaching if the components are within the scope of the fire protection system, have been installed in accordance with NFPA 24, and the activity of the jockey pump is monitored on an interval not to exceed one month. Additionally, the applicant stated that the exception is consistent with the fire protection aging management requirements of GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

Issue:

GALL Report AMP XI.M41 specifically states that the program does not address selective leaching, and that GALL Report AMP XI.M33 is applied in addition to this (AMP XI.M41) program. The internal and external environments both can lead to selective leaching in gray cast iron components, and potentially challenge the structural integrity of the component (e.g., piping). Selective leaching cannot be detected by flow monitoring or operation of a jockey pump. A hardness test or alternative mechanical examination is needed in order to confirm the absence or presence of selective leaching unless preventive measures such as cathodic protection are in place (for external surfaces).

Request:

Explain how buried gray cast iron components in the fire protection systems will be managed for loss of material due to selective leaching.

Callaway Response

The exception for the Selective Leaching program (B2.1.19) has been revised to inspect buried gray cast iron fire protection valves opportunistically. All buried gray cast iron components are valves in the fire protection system. In addition, the exception also requires that when any buried gray cast iron fire protection valves are removed from the fire protection system, then specimens from at least one of them will be sent to a laboratory for metallurgical testing to determine the extent, if any, of selective leaching. A minimum of two metallurgical tests will be performed within the five years prior to entering the period of extended operation.

In conjunction with opportunistic inspections and metallurgical evaluations of buried gray cast iron fire protection valves, monthly trending of jockey pump operation provides an additional indication of the system pressure boundary function. In addition buried component protective coatings provide an additional preventative measure against selective leaching aging.

LRA Appendix A1.19 and LRA Appendix B2.1.19 have been revised, as shown on Amendment 5 in Enclosure 2 to include the revised exception for the Selective Leaching program (B2.1.19).

Corresponding Amendment Changes

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

RAI B2.1.25-1

Background:

The “scope of program” program element of the Buried and Underground Piping and Tanks program states that the emergency diesel engine fuel oil storage and transfer system consists of buried piping and tanks with a safety-related function and contains hazardous materials. Based on a review of drawing LR-CW-JE-M-22-JE01, the emergency diesel engine fuel oil storage and transfer system also appears to include in-scope underground piping. However, LRA Table 3.3.2-21, “Auxiliary Systems – Summary of Aging Management Evaluation – Emergency Diesel Engine Fuel Oil Storage and Transfer System,” does not include any aging management review (AMR) items associated with underground piping.

Issue:

There appears to be an inconsistency between the license renewal drawing and the program description in regard to the existence of in-scope underground emergency diesel engine fuel oil storage and transfer system piping.

Request:

Clarify whether there is underground piping in the emergency diesel engine fuel oil storage and transfer system that is within the scope of license renewal. If there is underground piping within the scope of license renewal, describe how the piping will be managed for aging. Also, provide any necessary corrections to the LRA to reflect the change.

Callaway Response

License renewal boundary drawing LR-CW-JE-M-22-JE01 correctly shows underground carbon steel piping within the scope of license renewal for the criteria in 10 CFR 50.54 (a)(1). Therefore, LRA Table 3.3.2-21 has been revised to identify that aging of steel piping in an underground environment will be managed by AMP XI.M41 "Buried and Underground Piping and Tanks" (B2.1.25). LRA Appendix B2.1.25 has been revised to include the underground steel piping of the Emergency Diesel Engine Fuel Oil Storage and Transfer System as a component requiring aging management.

LRA Table 3.3.2-21 and Appendix B Section B2.1.25 have been revised, as shown on LRA Amendment 5 in Enclosure 2 to show the underground steel piping as a component requiring aging management by AMP XI.M41 "Buried and Underground Piping and Tanks" (B2.1.25).

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table "LRA Changes from RAI Responses”, for a description of LRA changes with 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 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

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.

RAI B2.1.25-3

Background:

The “preventive actions” program element of the Buried and Underground Piping and Tanks program states that the preventive actions of the program will be consistent with the GALL Report; however, during its audit the staff identified five CARs spanning 2006 through 2010 citing weakness in cathodic protection system performance. In addition, a Close-Interval Survey (CIS) and Direct Current Voltage Gradient (DCVG) Survey - Buried Fire Water Protection Piping, dated May 2008, stated that 23 percent of the fire protection system, representing 2,658 feet of piping, was inadequately protected. GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks,” recommends that a cathodic protection be installed, monitored, annually tested, and potential differences and current measurements be trended to identify changes in the effectiveness of the system.

Issue:

Paragraph 54.21 (d) of 10 CFR states, “[t]he FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging…” The staff believes that cathodic protection system performance is a key preventive measure for managing the aging effects of buried piping. Given that plant-specific operating experience demonstrates a long period of degraded performance of the cathodic protection system, further details on cathodic protection system availability and effectiveness should be included in the FSAR supplement summary description.

Request:

Revise the LRA Section A1.25 discussion of cathodic protection to include a discussion that the cathodic protection system meets NACE SP0169 or NACE RP0285, is monitored for effectiveness at least once a year, and potential difference and current measurements are trended to identify changes in the effectiveness of the systems and/or coatings.

Callaway Response

LRA Section A1.25 has been revised to state the following:

> The cathodic protection system is operated consistent with the guidance of NACE SP0169-2007 for piping and NACE RP0285-2002 for tanks. Trending of the cathodic protection system is performed to identify changes in the effectiveness of the system and to ensure that the rectifiers are available to protect buried components. An annual cathodic protection survey is performed consistent with NACE SP0169-2007.

LRA Appendix A1.25 and LRA Appendix B2.1.25 have been revised, as shown on LRA Amendment 5 in Enclosure 2 to discuss the cathodic protection system.

Corresponding Amendment Changes

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

RAI B2.1.25-4

Background:

The "detection of aging effects" program element of the Buried and Underground Piping and Tanks program states that the fire water jockey pump performance will be monitored in lieu of conducting excavated direct visual examinations of in-scope buried fire water system piping. The GALL Report AMP recommends a similar provision.

Issue:

The staff reviewed several CARs and noted that there have been numerous leaks in the fire water system piping. Thus, it is not clear to the staff that there is adequate sensitivity for monitoring buried fire water piping with the fire water jockey pump (i.e., cumulative time when the fire jockey pump is not running is sufficiently long to show a change in performance should a leak occur).

Request:

For the past five years, provide a summary of trend results for the fire water jockey pump that demonstrate that there is sufficient sensitivity to detect leaks in in-scope buried piping. If the trend results are not capable of demonstrating this, state the basis for why monitoring fire water jockey pump performance is sufficient to ensure that the fire water system will meet its intended function during the period of extended operation.

Callaway Response

Based on a review of the last 5 years of cycle time data, the Jockey Pump has not run constantly unless a large leak has occurred. Typically, trending shows that the jockey pump cycles on and off periodically to make up for minor leakage in the system (3 gpm leakage with approximately 15 minutes in between runs). Operation of the pump is monitored daily in the Control Room, and an alarm is received when run time becomes excessive (200 seconds). In addition, systems engineering performs monthly trending of the jockey pump as part of the Plant Health and Performance Monitoring Program. The jockey pump has been used successfully as a troubleshooting tool to locate leakage and quantify leaks. This is done by isolating portions of the system and checking run times on the jockey pump. With the combination of daily and monthly monitoring of the jockey pump run times, site staff has found the jockey pump has sufficient sensitivity to detect in-scope piping leaks.

Corresponding Amendment Changes

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

RAI B2.1.25-5

Background:

A CIS and DCVG Survey Buried Fire Water Protection Piping, dated May 7, 2008, recommended that for locations not meeting -850 mV criterion, the station should determine whether the alternative 100 mV potential shift criterion would demonstrate acceptable cathodic protection. In addition, it recommended that locations more negative than -1200 mV be addressed to ensure that coating disbondment is not occurring.

The “acceptance criteria” program element of AMP XI.M41 states that, “[c]riteria for soil-to-pipe potential are listed in NACE RP0285-2002 and SP0169-2007.” NACE SP0169-2007 Section 6.2.2.2.2 states, “[i]n some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient.” NACE SP0169-2007 Section 6.2.2.3.3 states, “[t]he use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating.”

Issue:

When dissimilar metals are present in the environment (e.g., steel in relation to the copper grounding grid) the 100 mV criterion is only acceptable if it can be demonstrated that the most noble metal will be adequately protected. If the applicant will utilize the 100 mV criterion on in-scope components during the PEO, it must provide the basis for protecting the most noble metal. In addition, in order to verify consistency with the GALL Report AMP XI.M41, the staff must understand the applicant’s approach to locations more negative than -1200mV.

Request:

Starting 10 years prior to and extending through the period of extended operation:

a) State whether the 100 mV polarization will be used as acceptance criterion. If the 100 mV polarization will be used in this time period, state the basis for how the most noble buried in-scope material will be adequately protected.

b) State whether as-left survey findings will be allowed to be more negative than -1200 mV, and if they will, state the basis for why protective coating disbondment will not occur.

Callaway Response

a) The Buried and Underground Piping and Tanks program will use the 100 mV polarization as an acceptance criterion based on protecting the most noble metal in a dissimilar metal environment consistent with NACE RP0169-2007 Section 6.2 criteria. Protection of the most noble buried in-scope material will consist of evaluating the buried metallic piping and tanks that are electrically tied together. Using published industry galvanic series charts, the most anodic material will be identified and then raised 100 mV greater than the published number in relation to the copper-copper sulfate half-cell. Instances where protection cannot be demonstrated with this method will be entered into the Corrective Action Program. The EPRI sponsored Cathodic Protection User’s Group will be used to provide operating experience associated with the 100 mV criteria.

b) While -1200 mV over-polarization, as defined in NACE SP0169-2007 (Section 6.2.3.2) and Peabody's Control of Pipeline Corrosion book second edition 2001 (page 62), only applies to aluminum piping, Callaway will consider this parameter as an upper bounding value. Any reading more negative than -1200 mV (instant off parameter only) will be investigated and corrective actions initiated as deemed appropriate.

Corresponding Amendment Changes

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

RAI B2.1.25-6

Background:

The “operating experience” program element of the Buried and Underground Piping and Tanks program, LRA Section B2.1.25, states that from 2008 to 2009, portions of the emergency service water (ESW) system were replaced with high density polyethylene (HDPE) piping due to material conditions of the system including pinhole leaks, pitting, and other localized degradation of the pressure boundary. LRA Table 3.3.2-4 states that there are steel piping, strainer and valve components in the ESW system exposed to raw water (internal) and a buried environment that have not been replaced. The Buried and Underground Piping and Tanks Inspection Program, Appendix A, Attachment 1, states that four inspections will be performed on steel ESW piping in each 10-year period starting 10 years prior to the period of extended operation.

Issue:

Given that these steel components are in the same environment as the replaced piping, it is possible that the degradation of the steel piping will occur at the same rate (on a unit length basis) as experienced in the past for the entire system. Also, given inconsistent site-wide performance of the cathodic protection system, the staff lacks sufficient information to determine that four inspections in each 10-year period will ensure that the intended function(s) of the portions of the ESW that have not been replaced with HDPE piping will be met during the period of extended operation.

Request:

State the basis for why four inspections in each 10-year period, starting 10 years prior to the period of extended operation, of buried steel piping in the ESW system is sufficient to ensure that the intended function(s) of the portions of the ESW will be met throughout the period of extended operation.

Callaway Response

NUREG-1801, Element 2 "Preventive Actions" requires coatings, proper backfill and cathodic protection for buried carbon steel piping. NUREG-1801 requires that for buried carbon steel piping in which coatings and backfill are in accordance with the requirements of NACE SP0169-2007, but for which cathodic protection has not been operated consistent with table 4a "Inspections of Buried Pipe" in AMP XI.M41, four inspections will be conducted within ten years of entering the period of extended operation (AMP XI.M41 Table 4a preventative category E).

The buried carbon steel piping in the essential service water system has been coated in accordance with NACE SP0169-2007. The backfill used for buried carbon steel piping in the essential service water system is consistent with ASTM D448-08 and is considered acceptable. Previously, the cathodic protection system had not been operated and maintained consistent with NACE guidelines. Therefore, performing four inspections on the buried steel essential service water piping during the 10 years prior to entering the period of extended operation is consistent with the requirements stated in NUREG-1801 in AMP XI.M41. However, within 10 years of entering the period of extended operation, if the cathodic protection system is upgraded to be operated and maintained consistent with

NACE SP0169-2007, Callaway will conduct one inspection in each ten year period, starting ten years prior to the period of extended operation.

After the cathodic protection system is upgraded to be operated and maintained consistent with NACE SP0169-2007, if plant operating experience indicates further degradation of the buried carbon steel pipe in the essential service water system, the number of inspections will be increased consistent with AMP XI.M41 element 4.f, adverse conditions.

Corresponding Amendment Changes

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

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 and ESW pumphouse.

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 4.7.8-1

Background:

LRA Section 4.7.8 dispositions the TLAA for the replacement of Class 3 piping with HDPE piping as in conformance with 10 CFR 54.21(c)(1)(i), meaning that, "[t]he analyses remain valid for the period of extended operation." Calculations 2007-13241 (Revision 1), Minimum Wall Thickness for ESW Buried HDPE Piping (ML082630799), and 2007-1670 (Revision 0), Buried HDPE Piping Stress Analysis (ML082630800), utilize a 40 year normal service life and include 30-day duration of peak post-accident conditions. LRA Section 4.7.8 states that the replacement of the buried ESW piping with HDPE material began in 2008. The staff further noted that the design analysis for 40 years surpasses the end of the period of extended operation for the applicant's site, October 2044.

Issue:

Based on a review of the UFSAR, the staff noted that other transient scenarios less severe than the postulated 30-day transient (e.g., inadvertent opening of a pressurizer safety or relief valve, minor steam system piping failure) could result in operating parameters which are higher than those for the 40-year life parameters and for which multiple frequencies could occur in the plant's expected life (i.e., 60 years). These other potential transients are not reflected in the calculations.

Request:

State why other transient scenarios less severe than the postulated 30-day transient are not included in the HDPE calculations and provide the basis for why they do not impact the 40-year life of the piping.

Callaway Response

The current requirement is that the essential service water (ESW) piping be analyzed for 40 years of normal operation after which it should be able to operate 30 days at post-accident conditions. The design scenario is accounted for in the calculation of the minimum wall thickness [ADAMS Accession No ML082630799]. Transient scenarios less severe than the postulated 30 day transient were not included in the HDPE calculations because they were not required by ASME Code Case N-755 or Relief Request I3R-10. ASME Code Case N-755 provides conditions under which polyethylene material may be used for ASME Section III, Division I, Class 3, buried piping systems. Relief Request I3R-10 granted approval to implement ASME Code Case N-755 at Callaway with alterations [ADAMS Accession No. ML081580011]. The omission of these transients from the HDPE calculations does not impact the 40-year life of the piping because the heat loads transferred to the ESW piping during the events are within those considered under normal operating conditions or there is sufficient margin in the HDPE calculations to accommodate those transients of lesser severity.

The heat loads for ESW system for normal, post-accident, and shutdown conditions are presented in FSAR SP Table 9.2-2 through FSAR SP Table 9.2-4. The two most substantial heat loads on the ESW system are the component cooling water (CCW) system and the containment coolers. FSAR SP Table 9.2-2 through FSAR SP Table 9.2-4 identify that the heat load for the CCW system is determined by the residual heat removal (RHR) system during shutdown and accident conditions. The conditions under which the RHR

system is placed in service are controlled by the technical specifications and associated procedures. This ensures the ESW system is maintained within the design. Therefore the only transients that could potentially result in the ESW return piping exceeding its design temperature of 105°F, and thus being classified as post-accident conditions, are those transients that result in energy being transferred to the containment environment. A review of FSAR Chapter 15 identified the following Condition II and III transients that could result in a release of energy to the containment environment.

- Inadvertent Opening of a Steam Generator Relief or Safety Valve (Condition II, FSAR Chapter 15.1.4)
- Inadvertent Opening of a Pressurizer Safety or Relief Valve (Condition II, FSAR Chapter 15.6.1)
- Break In Instrument Line or Other Lines from Reactor Coolant Pressure Boundary that Penetrate Containment (Condition II, FSAR Chapter 15.6.2)
- Loss-of-coolant accidents resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary (small break) (Condition III, FSAR 15.6.5)
- Steam system piping failure (Condition III, FSAR 15.1.5)

The Condition II transients will not result in the ESW return piping exceeding its normal design temperature of 105°F. The vent paths for the Condition II transients do not discharge to the containment atmosphere and would not increase the containment temperature. Therefore, an increase to the ESW return piping temperature would not be expected. Even if conditions resulted in a release to the containment atmosphere, e.g. blown pressurizer relief tank rupture disk, the accident requires that the Reactor Coolant System (RCS) be at normal operating pressure (NOP). With the RCS at NOP, the RHR system would not be aligned to the RCS. Since the RHR system accounts for most of the heat load on the ESW system; there would be sufficient heat removal capacity to prevent the ESW return piping from exceeding its normal design temperature of 105°F.

Condition III transients occur very infrequently during the life of the plant but may result in the ESW water increasing to greater than the normal design temperature of 105°F. The design basis assumes 5 small LOCA events and 5 small steam line break events. The ESW return piping temperature during these Condition III transients would be much closer to the normal design temperature versus the post-accident design temperature of 175°F. The Large Break LOCA event itself only results in an ESW temperature of 140°F and the mass and energy released during a small break event is a fraction of the release during a design basis event. The peak post-LOCA ESW temperature will only be short-lived and the long-term post-LOCA discharge temperature will be significantly lower. Given that the maximum ESW temperature and the duration at the maximum temperature were analyzed at a much greater value than those actually expected; the current analysis is sufficient to account for the Condition III transients.

There is also inherent conservatism in the HPDE design during normal operation. The normal operating conditions of the HDPE calculation cover both the normal and shutdown conditions. Of the two conditions, shutdown puts much more heat load on the ESW system and thus will result in higher temperatures. While the design accounts for 40 years at shutdown conditions, it will only be experienced for a fraction of the time. In addition, the design shutdown conditions are only experienced for a short period of time, with the peak

CCW temperature occurring after ~1 day after shutdown and then falling rapidly due to the decrease in decay heat.

Corresponding Amendment Changes

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

RAI 2.4.7-1

Callaway LRA Section 2.4.7, “In-Scope Tank Foundations and Structures” lists only the Category I safety-related RWST and valvehouse, the safety-related CST and the FWST as the tanks in scope of license renewal for that specific section. In regards to the structural foundations and supports of other safety-related tanks that are not specifically called out in the LRA, such as the component cooling water surge tank and the chemical and volume control system tank, it is not clear if the tank supports are analyzed under the specific LRA section that describes the structure that houses the tank, or as a separate commodity, such as LRA Section 2.4.7.

Please provide a brief description of the general methodology used to categorize the tanks within the LRA.

Callaway Response

LRA Section 2.4.7, In-Scope Tank Foundations and Structures, addresses the evaluation of the foundations and other structures associated with the refueling water storage tank, the condensate storage tank, and the fire water storage tanks. The foundations and associated structures for other in-scope tanks are evaluated as part of the buildings in which these tanks are located. For example, the component cooling water surge tanks are founded on a concrete slab within the auxiliary building. This slab is evaluated under component type “Concrete Elements” in LRA Table 2.4-3. Supports that connect in-scope tanks to their foundations are evaluated as commodities in LRA Section 2.4.12, Supports. These supports are included in LRA Table 2.4-12 as component types “Supports Mech Equip Class 1”, “Supports Mech Equip Class 2 and 3”, or “Supports Mech Equip Non ASME”, depending on the code class of the particular tank. Foundations and supports for all in-scope tanks are within the scope of license renewal and subject to aging management review. Tanks are evaluated in their associated mechanical systems.

Corresponding Amendment Changes

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

Amendment 5, LRA Changes from RAI Responses

Enclosure 2 Summary Table

Affected LRA Section/Table	LRA Page
Table 3.3.2-10	3.3-125, 126, 136, 140, 141, 142, 144, and 145
Table 3.3.2-21	3.3-217
Table 3.3.2-22	3.3-226 and 3.3-237
Table 3.5.2-1	3.5-59 and 3.5-60
Section A1.14	A-8
Section A1.15	A-8
Section A1.19	A-10
Section A1.25	A-13
Table A4-1 item 7	A-37
Table A4-1 item 10	A-38
Table A4-1 item 11	A-39
Section B2.1.11	B-45 to B- 47
Section B2.1.14	B-53 to B-56
Section B2.1.15	B-57 to B-59
Section B2.1.19	B-69 to B-71
Section B2.1.25	B-87 to B-90

Changed the internal environment of several components from demineralized water to closed cycle cooling water. Added a line for a stainless steel valve with an internal environment of closed cycle cooling water. Added a new line item for the internal surface of a tank exposed to condensation. No new Plant Notes are added.

Table 3.3.2-10, Chemical and Volume Control System, (Page 3.3-125, 126, 136, 140, 141, 142, 144, and 145) is revised as follows (deleted text shown in strikethrough and new text underlined):

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Flow Element	LBS	Carbon Steel	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.D1.SP-74~~ VII.C2.AP-202	~~3.4.1.013~~ 3.3.1.045	A
Heat Exchanger (CVCS BTRS Letdown Chiller)	LBS	Carbon Steel	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.E.SP-77~~ VII.C2.AP-189	~~3.4.1.015~~ 3.3.1.046	A
Heat Exchanger (CVCS BTRS Letdown Chiller)	LBS	Stainless Steel	~~Demineralized Water (Ext)~~ Closed Cycle Cooling Water (Ext)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.E.SP-80~~ VII.C2.A-52	~~3.4.1.016~~ 3.3.1.049	A

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Lube Oil Cooler)	LBS	Copper Alloy	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.A.SP-101~~ VII.E1.AP-203	~~3.4.1.016~~ 3.3.1.046	A
Pump	LBS	Carbon Steel	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.D1.SP-74~~ VII.C2.AP-202	~~3.4.1.013~~ 3.3.1.045	~~A~~ C
Solenoid Valve	LBS	Copper Alloy (> 15% Zinc)	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	Selective Leaching (B2.1.19)	~~VII.C2.AP-32~~ VII.C2.AP-43	3.3.1.072	B
Solenoid Valve	LBS	Copper Alloy (> 15% Zinc)	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.A.SP-101~~ VII.C2.AP-199	~~3.4.1.016~~ 3.3.1.046	A

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Strainer	LBS	Copper Alloy	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.A.SP-101~~ VII.C2.AP-199	~~3.4.1.016~~ 3.3.1.046	A
Tank	LBS	Carbon Steel	~~Demineralized Water (Int)~~ Closed Cycle Cooling Water (Int)	Loss of material	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)~~ Closed Treated Water Systems (B2.1.11)	~~VIII.D1.SP-74~~ VII.C2.AP-202	~~3.4.1.013~~ 3.3.1.045	~~C~~ A
Tank	LBS	Carbon Steel	Condensation (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)	VII.E5.AP-280	3.3.1.095	B
Valve	PB, LBS	Carbon Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed Treated Water Systems (B2.1.11)	VII.H2.AP-202	3.3.1.045	A
Valve	LBS	Stainless Steel	Closed Cycle Cooling Water (Int)	Loss of material	Closed Treated Water Systems (B2.1.11)	VII.C2.A-52	3.3.1.049	A

Table 3.3.2-21 was revised to include "Underground" external environment for piping components in the diesel fuel oil storage tank access vaults within the scope of license renewal to resolve RAI B2.1.25-1.

Table 3.3.2-21 (page 3.3-217) is revised as follows (new text underlined):

Table 3.3.2-21 Auxiliary Systems – Summary of Aging Management Evaluation – Emergency Diesel Engine Fuel Oil Storage and Transfer System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping	LBS, PB, SIA	Carbon Steel	Underground (Ext)	Loss of material	Buried and Underground Piping and Tanks (B2.1.25)	VII.I.AP-284	3.3.1.109a	B

Added cracking as an aging effect for stainless steel valves and heat exchanger components with an environment of closed cycle cooling water. No new Plant Notes are added.

Table 3.3.2-22, Standby Diesel Generator Engine System (Page 3.3-226 and 3.3-237) is revised as follows (deleted text shown in strikethrough and new text underlined):

Table 3.3.2-22 Auxiliary Systems – Summary of Aging Management Evaluation – Standby Diesel Generator Engine System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (DG Jacket Water)	HT, PB	Stainless Steel	Closed Cycle Cooling Water (Ext)	Cracking	Closed Treated Water Systems (B2.1.11)	VII.C2.A-186	3.3.1.043	C
Valve	PB	Stainless Steel	Closed Cycle Cooling Water (Int)	Cracking	Closed Treated Water Systems (B2.1.11)	VII.C2.A-186	3.3.1.043	A

Revise to include additional GALL lines for the Emergency Airlock and Personnel Airlock to assign the Fire Protection AMP for managing the aging effect of loss of material.

Table 3.5.2-1, Reactor Building, (pages 3.5-59 and 3.5-60) is revised as follows (new text shown underlined):

Table 3.5.2-1 Containments, Structures, and Component Supports – Summary of Aging Management Evaluation - Reactor Building (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Hatch Emergency Airlock	FB, SH, SLD, SPB, SS	Carbon Steel	Plant Indoor Air (Structural) (Ext)	Loss of material	Fire Protection (B2.1.13)	VII.G.A-21	3.3.1.059	A
Hatch Personnel Airlock	FB, SH, SLD, SPB, SS	Carbon Steel	Plant Indoor Air (Structural) (Ext)	Loss of material	Fire Protection (B2.1.13)	VII.G.A-21	3.3.1.059	A

A1.14 FIRE WATER SYSTEM

The Fire Water System program manages loss of material for water-based fire protection systems. Consistent with National Fire Protection Association (NFPA) commitments, the program consists of periodic full-flow flush tests and system performance tests to prevent corrosion from biofouling in the fire protection system. The fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

The Fire Water System program conducts flow tests through each open head spray/sprinkler nozzle to verify water flow is unobstructed. Prior to 50 years in service, the Fire Water System program requires sprinkler heads to be replaced or have representative samples submitted for field-service testing by a recognized testing laboratory in accordance with NFPA 25. The program field-service tests additional representative samples every 10 years thereafter during the period of extended operation to ensure signs of aging are detected in a timely manner.

Non-intrusive wall thickness evaluations are performed on fire water piping to identify loss of material. As an alternative, visual internal inspections are used when the internal surface of the piping is exposed during plant maintenance. These inspections evaluate (a) wall thickness to ensure against catastrophic failure and (b) the inner diameter of the piping as it applies to the design flow of the fire protection system.

A1.15 ABOVEGROUND METALLIC TANKS

The Aboveground Metallic Tanks program manages loss of material and cracking on the external surfaces of aboveground metallic tanks within the scope of license renewal that are supported on concrete or soil. The program also manages cracking, blistering, and change in color of the acrylic/urethane insulation on the condensate storage tank (CST). The program applies to the ~~condensate storage tank~~ CST, refueling water storage tank (RWST), and the two fire water storage tanks (FWSTs).

For the carbon steel fire water storage tanks, the program relies on application of paint, coating, or tank bottom edge grout as corrosion preventive measures. In addition, cathodic protection is used as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks.

This program performs visual inspections to monitor for aging of the tank external surface paint or damage of the insulation covering. Removal of the tank insulation ~~is on an opportunistic basis to~~ permits a sampling ~~inspection~~ of the tank external surfaces to be inspected for aging. ~~Insulated tank exterior surfaces that have not been opportunistically inspected will be examined with thickness measurements from the internal surface, to determine the tank wall thickness.~~

Thickness measurements are taken from inside the emptied tanks to determine the thickness of the tank bottom~~, or insulated tank exterior surfaces that have not had an opportunistic inspection~~. The thickness measurements ensure significant loss of material is not occurring, so that the intended function of each tank is maintained during the period of extended operation.

The chemical treatments of cooling tower water do not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks. Within five years of entering the period of extended operation, a one-time soil surface sample near the CST and RWST will be performed. The soil surface sample will be evaluated to ensure that chlorides or other aggressive cooling tower water treatment chemicals are not creating an aggressive environment that would degrade the CST, RWST, or their insulation jacketing.

The Aboveground Metallic Tanks program is a new program that will be implemented within five years of entering ~~prior to~~ the period of extended operation.

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

A1.19 SELECTIVE LEACHING

The Selective Leaching program manages loss of material due to selective leaching for gray cast iron and copper alloy with greater than 15 percent zinc components that are exposed to treated water, raw water, waste water, or groundwater environments and require aging management. The material of copper alloy greater than eight percent aluminum (aluminum-bronze) was not used in systems that require aging management at Callaway.

The Selective Leaching program includes a one-time visual inspection and other mechanical inspection techniques of selected components that may be susceptible to selective leaching. If these inspections detect selective leaching, then a follow-up evaluation is performed. The evaluation may require confirmation of selective leaching through a metallurgical evaluation. This is to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended functions for the period of extended operation. Buried gray cast iron fire protection valves will be inspected opportunistically. In addition, when any buried gray cast iron valves are removed from the fire protection system, then specimens from at least one of them will be sent to a laboratory for metallurgical testing to determine the extent, if any, of selective leaching of the valve. A minimum of two metallurgical tests will be performed within the five years prior to entering the period of extended operation.

The Selective Leaching program is a new program and inspections will be completed within the five-year period prior to the period of extended operation.

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

A1.25 BURIED AND UNDERGROUND PIPING AND TANKS

The Buried and Underground Piping and Tanks program manages loss of material, cracking, blistering, and change of color of the external surfaces of buried and underground piping and tanks. The program augments other programs that manage the aging of internal surfaces of buried and underground piping and tanks. The materials managed by this program include steel, stainless steel and high-density polyethylene. The program manages aging through preventive, mitigative, and inspection activities. .

Preventive and mitigative actions include selection of component materials, external coatings for corrosion control, backfill quality control and the application of cathodic protection. The cathodic protection system is operated consistent with the guidance of NACE SP0169-2007 for piping, and NACE RP 0285-2002 for tanks. Trending of the cathodic protection system is performed to identify changes in the effectiveness of the system and to ensure that the rectifiers are available to protect buried components. An annual cathodic protection survey is performed consistent with NACE SP0169-2007.

Inspection activities include ~~electrochemical verification of the effectiveness of cathodic protection,~~ non-destructive evaluation of pipe or tank wall thickness, and visual inspection of the exterior, as permitted by opportunistic or directed excavations.

The Buried and Underground Piping and Tanks program is a new program that will be implemented within the 10-year period prior to entering the period of extended operation.

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

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
7	Enhance the Closed Treated Water Systems Program procedures to: • include visual inspections of the surfaces of components with a closed treated water systems water environment. Representative samples of each combination of material and water treatment program will be visually inspected at least every ten years or opportunistically when consistent with sample requirements. <u>Sample locations will be selected based on the likelihood of corrosion and cracking.</u> Inspections will be conducted and evaluated consistent with ASME Code inspections, industry standards, or a plant-specific inspection procedure by personnel qualified to detect aging. If adverse conditions are found, additional examinations will be performed. This periodic inspection will determine the extent of cracking, loss of material and fouling, and serves as a leading indicator of the condition of the interior of piping components otherwise inaccessible for visual inspection.	B2.1.11	Prior to the period of extended operation

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
10	Enhance the Fire Water System program procedures to: • include non-intrusive pipe wall thickness examinations on fire water piping. As an alternative to wall thickness examinations, internal inspections will be performed on accessible exposed portions of fire water piping during plant maintenance activities. Pipe wall thickness examinations and/or internal inspections will be performed prior to the period of extended operation and at 10-year frequencies throughout the period of extended operation. • replace sprinkler heads prior to 50 years in service or have a recognized testing laboratory field-service test a representative sample in accordance with NFPA 25 and test additional samples every 10 years thereafter to ensure signs of aging are detected in a timely manner. • review and evaluate trends in flow parameters recorded during the NFPA 25 fire water flow tests. • perform annual hydrant flow testing in accordance with NFPA 25 • perform annual hydrostatic testing of fire brigade hose • recoat internal surface of fire water storage tanks	B2.1.14	Prior to the period of extended operation

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
11	Implement the Aboveground Metallic Tanks program as described in LRA Section B2.1.15	B2.1.15	Within five years of entering ~~Prior to~~ the period of extended operation

B2.1.11 Closed Treated Water Systems

Program Description

The Closed Treated Water Systems program manages loss of material, cracking, and reduction of heat transfer for components within the scope of license renewal in closed-cycle treated water cooling systems.

The Closed Treated Water Systems program is a preventive program that is consistent with the guidelines of EPRI 1007820, *Closed Cooling Water Chemistry Guideline*. The program relies on water treatment, including the use of corrosion inhibitors to modify the chemistry of the water and chemical testing to ensure that water chemistry is maintained within acceptable guidelines. The program uses ~~four~~ the following treatment programs for chemistry control: nitrite/molybdate control with tolyltriazole (boron thermal regeneration system), molybdate control with tolyltriazole (~~closed treated water systems~~ component cooling water system and central chilled water system), ethylene glycol (plant heatingsystem), nitrite control with tolyltriazole (emergency diesel generator jacket water), or Diesel Coolant Additive (DCA) and ethylene glycol (fire protection diesel jacket water). The adequacy of chemistry control is confirmed by routine sampling and monitoring, which is performed at least quarterly.

The program also conducts periodic inspections to determine the presence or extent of corrosion, fouling, and/or cracking. Representative samples of each combination of material and water treatment program are visually inspected at least every 10 years or opportunistically when consistent with sample requirements. Sample locations will be selected based on the likelihood of corrosion and cracking. Inspections are conducted and evaluated consistent with ASME Code inspections, industry standards, or a plant-specific inspection procedure by personnel qualified to detect aging. If adverse conditions are found, additional examinations will be performed and appropriate corrective action taken.

NUREG-1801 Consistency

The Closed Treated Water Systems program is an existing program that, following enhancement, will be consistent with NUREG-1801 Section XI.M21A, *Closed Treated Water Systems*.

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), Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)

Procedures will be enhanced to include visual inspections of the surfaces of components with a closed treated water systems water environment. Representative samples of each combination of material and water treatment program will be visually inspected at least every 10 years or opportunistically when consistent with sample requirements. Sample locations will be selected based on the likelihood of corrosion and cracking. Inspections will be conducted and evaluated consistent with ASME Code inspections, industry standards, or a plant-specific inspection procedure by personnel qualified to detect aging. If adverse conditions are found, additional examinations will be performed. This periodic inspection will determine the extent of cracking, loss of material and fouling, and serves as a leading indicator of the condition of the interior of piping components otherwise inaccessible for visual inspection.

Operating Experience

The following discussion of operating experience provides objective evidence that the Closed Treated Water Systems program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation.

1. Based on a review of 10 years of operating experience, no instances were identified where aging effects arising from closed-cycle cooling water have led to the loss of the intended function of any of the heat exchangers served by the systems within the scope of this program.

2. In 2002, cracks were found by ultrasonic examination conducted in the outlet nozzle area of the letdown heat exchanger. These cracks were approximately 50 percent through wall and ½ in. in length from under the weld. The cracks were in the base metal of the heat exchanger shell. These inspections were conducted as a result of cracks found by Wolf Creek during inspections of their letdown heat exchanger nozzle. The apparent cause was stress corrosion cracking. The Callaway extent of condition was two cracks in the shell material where the CCW outlet nozzle is connected. A section of the letdown heat exchanger shell and the CCW outlet nozzle was replaced with identical material (SA-106, Grade B) as a permanent repair. No additional cracking was found by follow-up inspections.

3. In 2008, pitting was discovered in the carbon steel piping of the emergency diesel generator jacket water closed cycle cooling system. This pitting was minor, and did not affect the gasket sealing surface. The pitting was reduced by polishing and it was determined that the pitting would not affect the intended function of the piping.

The operating experience of the Closed Treated Water Systems program did not show any adverse trend in performance. Occurrences that would be identified under the Closed Treated Water Systems 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 continued implementation of the Closed Treated Water Systems program will effectively identify aging prior to loss of intended function.

Conclusion

The continued implementation of the Closed Treated Water Systems program, following enhancement, provides 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.

B2.1.14 Fire Water System

Program Description

The Fire Water System program manages loss of material for water-based fire protection systems consisting of aboveground, buried and underground piping, fittings, valves, fire pump casings, sprinklers, nozzles, hydrants, hose stations, standpipes and water storage tanks. Periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests in accordance with National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended function. The fire protection system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated.

The Fire Water System program performs a flow test of the system at least once every three years in accordance with plant procedures meeting the requirements of NFPA 25, including a yard fire loop flush and a flush of associated hydrants. A visual inspection and flow test of yard fire hydrants is performed annually in accordance with NFPA 25.

The Fire Water System program conducts flow tests through each open head spray/sprinkler nozzle in accordance with NFPA 25, to verify water flow is unobstructed. Prior to 50 years in service, the Fire Water System program requires sprinkler heads to be replaced or have representative samples submitted for field-service testing by a recognized testing laboratory in accordance with NFPA 25. The program field-service tests additional representative samples every 10 years thereafter during the period of extended operation to ensure signs of aging are detected in a timely manner.

Pipe wall thickness examinations are performed on fire water piping using non-intrusive techniques. As an alternative to wall thickness examinations, internal inspections are performed on accessible exposed portions of fire water piping during plant maintenance activities. The inspections evaluate wall thickness measurements to ensure against catastrophic failure and the inner diameter of the piping as it applies to the design flow of the fire protection system. If a representative number of inspections have not been completed prior to the period of extended operation, Callaway will determine what additional inspections or examinations are required. The representative sample will be selected, based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or periodic flushes. If material and environment conditions for above grade and below grade piping are similar, the results of the inspections of the internal surfaces of the above grade fire water piping can be extrapolated to evaluate the condition of the internal surfaces of the below grade fire water piping. If not, additional inspection activities will be performed to ensure that the intended function of below grade fire water piping will be maintained consistent with the current licensing basis. Pipe wall thickness examinations and/or internal inspections will be performed prior to the period of extended operation and at 10-year frequencies throughout the period of extended operation.

Functional tests are periodically performed on fire detectors to ensure that they are operable

The fire water storage tank external surfaces are inspected and volumetric examinations of the tank bottom are performed as described in the Aboveground Metallic Tanks program (B2.1.15). External surfaces of buried fire main piping are evaluated as described in the Buried and Underground Piping and Tanks program (B2.1.25).

NUREG-1801 Consistency

The Fire Water System program is an existing program that, following enhancement, will be consistent, with exception to NUREG-1801, Section XI.M27, *Fire Water System*.

Exceptions to NUREG-1801

Program Element Affected:

Detection of Aging Effects (Element 4)

NUREG-1801 requires inspection of fire protection systems in accordance with the guidance of NFPA-25. Callaway performs power block hose station gasket inspections at least once every 18 months. The inspection interval is in accordance with the approved fire protection program, as described in FSAR Table 9.5.1-2 - SP, Section 5.4, rather than annually as specified by NFPA-25.

NUREG-1801 requires annual testing of fire hydrant hose. Callaway hydrostatically tests fire hoses at fire interior hose stations five years from installation and every three years thereafter. The testing interval is in accordance with the approved fire protection program, as described in FSAR Table 9.5.1-2 - SP, Section 5.6.

Enhancements

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

Preventive Actions (Element 2)

The Fire Water Storage Tanks internal surfaces will be recoated prior to the period of extended operation.

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

The Fire Water System program will be enhanced to include non-intrusive pipe wall thickness examinations on fire water piping. As an alternative to wall thickness examinations, internal inspections will be performed on accessible exposed portions of fire water piping during plant maintenance activities. Pipe wall thickness examinations and/or internal inspections will be

performed prior to the period of extended operation and at 10-year frequencies throughout the period of extended operation.

Detection of Aging Effects (Element 4)

The Fire Water System program will be enhanced to include annual hydrostatic testing of fire brigade hose.

The Fire Water System program will be enhanced such that prior to 50 years in service, sprinkler heads will be replaced or representative samples will be submitted for field-service testing by a recognized testing laboratory in accordance with NFPA 25. The program will field-service test additional representative samples every 10 years thereafter to ensure signs of aging are detected in a timely manner.

Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

The Fire Water System program will be enhanced to include annual hydrant flow testing in accordance with NFPA 25.

Monitoring and Trending (Element 5)

The Fire Water System program will be enhanced to review and evaluate trends in flow parameters recorded during the NFPA 25 fire water flow tests.

Operating Experience

The following discussion of operating experience provides objective evidence that the Fire 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 2005, during a surveillance test, 10 sprinkler heads had signs of corrosion or mechanical damage. Two of the sprinkler heads were replaced, and the other eight were cleaned. There have been no additional issues with the sprinkler heads since then.

2. In 2005, an alarm was triggered for fire protection loop jockey pump excessive run time and an investigation was initiated to identify the leak. The location of the leak was determined and promptly isolated from the main fire water loop. The isolation of the leak did not affect any required suppression systems. The leak was promptly repaired and the fire water piping was returned to service.

3. In 2006, a low C-factor lead to the fire water system being chemically cleaned, resulting in removal of approximately 8900 pounds of corrosion products. The cleaning was successful in keeping the system C-factor above 91.5 as required by plant procedure. During the chemical cleaning, five leaks developed, all of which were repaired. Since that time, two additional leaks have occurred. One was due to a cracked valve, and the cause of the other is still under investigation.

4. In 2008, during microbiological sampling of the fire water system, elevated levels of microbiologically influenced corrosion (MIC) were detected in stagnant portions of fire water pipe supplying fire water to hose stations. As a result, a new preventive maintenance task has been created to flush hose stations with a biocide.

5. In 2011, C-factor testing was performed on the main fire loop piping to check for restrictions due to corrosion and or biofouling. The testing results did not meet the acceptance criteria, indicating excessive pressure drop leading to reduced fire water flow. The testing results were called into question so with more accurate digital crystal gauges, the system was reevaluated and the results improved by 6% to 89.5, still less than the required acceptance criteria of 91.5. A functionality determination concluded that provided compensatory measures were taken, the reduced cleanliness could be fully offset so the required fire water flow rate could be achieved and maintained. As a corrective action, the acceptance criteria in Calculation KC-005 Addendum 2 have been modified, and the test procedure updated accordingly. These revisions provide significant margin and consider the cleanliness trends, ensuring the fire water system is capable of performing its intended function.

The above examples provide objective evidence that the existing Fire Water System program includes activities that are capable of detecting aging effects, evaluating system leakage, and initiating corrective actions. Occurrences that would be identified under the Fire 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 Fire Water System program will effectively identify aging prior to loss of intended function.

Conclusion

The continued implementation of the Fire Water System program, following enhancement, provides 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.

B2.1.15 Aboveground Metallic Tanks

Program Description

The Aboveground Metallic Tanks program manages cracking and loss of material on the external surfaces of outdoor, aboveground metallic tanks within the scope of license renewal that are supported on concrete or soil. The program also manages cracking, blistering, and change in color of the acrylic/urethane insulation on the condensate storage tank (CST). The program applies to the CST, refueling water storage tank (RWST), and the two fire water storage tanks (FWSTs). Tanks inside plant structures and protected from the outdoor environment are managed by the External Surfaces Monitoring of Mechanical Components program (B2.1.21).

The Aboveground Metallic Tanks program is a condition monitoring program that performs periodic inspections to monitor for aging effects on the external surfaces of the tank. For the carbon steel FWSTs, the program relies on the application of paint, coatings, or tank bottom edge grout as corrosion preventive measures. In addition, cathodic protection is used on the carbon steel FWSTs as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks. For the stainless steel CST and RWST, jacketed insulation with overlapping seams that prevent moisture intrusion or spray-on polyurethane foam insulation that adheres to tank surfaces are used as a corrosion preventive measure. There are no sealants or caulkings applied at the external interfaces between the FWST, CST, and RWST and their concrete or soil foundations.

This program performs visual inspections to monitor for aging of the tank external surface paint or damage of the insulation covering. Removal of the tank insulation ~~is on an opportunistic basis, to~~ permits a sampling ~~inspection~~ of the tank external surfaces to be inspected for aging. Insulation is removed for inspection of the tank surface if insulation damage is detected that would permit water ingress to the tank metallic surface. Painted exterior tank metallic surfaces are inspected for signs of degradation such as flaking, cracking, and peeling, to manage loss of material of the metallic surfaces.

~~Insulated tank exterior surfaces that have not been opportunistically inspected will be examined with ultrasonic test (UT) thickness measurements from the internal surface, to determine the tank wall thickness. Tank wall thickness measurements for insulated tank exterior surfaces that have not had an opportunistic inspection will be performed on a sampling basis when the tank is drained and within five years of entering the period of extended operation.~~

The chemical treatments of cooling tower water do not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks. Within five years of entering the period of extended operation, a one-time soil surface sample near the CST and RWST will be performed. The soil surface sample will be evaluated to ensure that chlorides or other aggressive cooling tower water treatment chemicals are not creating an aggressive environment that would degrade the CST, RWST, or their insulation jacketing.

This program also performs UT thickness measurements of the bottom of the tank from the internal surface, to determine the thickness of the tank bottom. With exception of the FWSTs, tank bottom UT thickness measurements will be performed when the tank is drained and within five years of entering the period of extended operation. Tank bottom UT thickness measurements of each FWST will be performed at least once every 10 years.

The Aboveground Metallic Tanks program is a new program that will be implemented within five years of entering ~~prior to~~ the period of extended operation.

NUREG-1801 Consistency

The Aboveground Metallic Tanks program is new program that, when implemented, will be consistent with exception to NUREG-1801, Section XI.M29, *Aboveground Metallic Tanks*.

Exceptions to NUREG-1801

Program Element Affected

Detection of Aging Effects (Element 4)

NUREG-1801 requires UT thickness measurements of the tank bottoms whenever the tank is drained and at least once within five years of entering the period of extended operation. UT thickness measurements of the bottom of each FWST from the internal surface, to determine the thickness of the tank bottom will be performed at least once every ten years. Currently the internal surface of each FWST tank bottom will be visually inspected on an alternating refueling outage frequency. UT thickness measurements may be performed sooner if required by further evaluation of the tank bottom visual inspection results. Ten year periodic UT thickness measurements, supplemented when appropriate based on internal visual examinations, will be effective in managing loss of material of the tank bottoms.

Enhancements

None

Operating Experience

The following discussion of operating experience provides objective evidence that the Aboveground Metallic Tanks 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 2007, an inspection of the train B fire water storage tank, performed in accordance with the Callaway fire water storage tank inspection procedure, identified small amounts of corrosion and mineral deposits, generally at the weld seams. An evaluation determined another application of the tank coating would be planned. In 2009, an inspection of the train B fire water storage tank identified several areas of blistering in the coating, mainly near the welds, and calcium deposits. No major delaminations were identified, and the anodes were in good shape. Minor corrosion was identified on bare metal surfaces, with no pitting. An evaluation determined that the tank internal surfaces were satisfactory.

In 2011, an inspection of the train B fire water storage tank was performed. Little to no damage or degradation was found to the internal metallic surface of the tank. There was some surface roughness/pitting when compared to clean bare metal. General blistering and some local delamination of the coating was found. The blistering on the wall and most of the floor is intact, while there was heavy blistering near the welds with smaller blistering on general plate areas. Since the fire water storage tanks are cathodically protected and most of the blisters were intact, the substrate is not expected to degrade significantly by the next inspection or re-coating, and no repair to the exposed metal is necessary.

2. In 2008, an inspection of the train A fire water storage tank identified minor blistering and limestone deposits. No corrosion was found on the tank internal surface, and the tank cathodic protection was found in satisfactory condition. The internal surface of the tank was determined to be in satisfactory condition. In 2010, an inspection of the train A fire water tank identified discontinuities and delaminations of the coating. The weld at the floor to wall interface had the most pitting, and weld locations contained heavy blistering. The adjustments on the rectifier of the cathodic protection system were found to be adequate. An evaluation determined that, since the cathodic protection system was determined to be effective, through voltage and current measurements, the substrate would not degrade excessively before the next planned inspection.

The above examples provide objective evidence that the new Aboveground Metallic Tanks program will be capable of detecting the aging effects associated with this program. Occurrences that would be identified under the Aboveground Metallic Tanks program will be evaluated to ensure there is no significant impact to the 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 Aboveground Metallic Tanks 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 Aboveground Metallic Tanks 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.

B2.1.19 Selective Leaching

Program Description

The Selective Leaching program manages loss of material due to selective leaching for gray cast iron and copper alloy with greater than 15 percent zinc components exposed to treated water, raw water, waste water, or groundwater that are within the scope of license renewal. There are no copper alloy components with greater than eight percent aluminum within the scope of license renewal at Callaway. Components susceptible to selective leaching are in the fire protection system, chemical and volume control system, service water system, compressed air system, essential service water system, plant heating system, fuel building HVAC system, auxiliary building HVAC, containment purge system or oily waste system.

A one-time inspection of a selected representative sample of components that are most susceptible to selective leaching will be performed. A sample of 20 percent of the population, up to a maximum of 25 component inspections, is established for each material and environment combination~~.~~ with the exception of buried gray cast iron fire protection components. Buried gray cast iron fire protection valves will be inspected opportunistically. In addition, when any buried gray cast iron valves are removed from the fire protection system, then specimens from at least one of them will be sent to a laboratory for metallurgical testing to determine the extent, if any, of selective leaching of the valve. A minimum of two metallurgical tests will be performed within the five years prior to entering the period of extended operation.

Visual and mechanical methods are used to determine whether loss of material due to selective leaching is occurring. Identification of selective leaching may be accomplished by attempting to scrape or chip through the surface being inspected. If these inspections detect dezincification or graphitization, which are the types of selective leaching expected to occur in copper alloy and gray cast iron, a follow-up evaluation will be performed. The evaluation may require confirmation of selective leaching through a metallurgical evaluation (which may include microstructure examination). The sample size for each material and environment combination may be expanded, based upon the results of the evaluation and confirmatory testing. If indications of selective leaching are confirmed, follow-up examinations will be performed. Deficiencies are corrected through replacement, to ensure that systems will continue to perform their intended function for the period of extended operation.

The Selective Leaching program is a new program and visual inspections and associated evaluations will be implemented within the 5-year period prior to the period of extended operation.

NUREG-1801 Consistency

The Selective Leaching program is a new program that, when implemented, will be consistent, with exception to NUREG-1801, Section XI.M33, *Selective Leaching*.

Exceptions to NUREG-1801

Program Elements Affected:

Detection of Aging Effects (Element 4)

NUREG 1801, Section XI.M33 requires visual inspection and hardness measurement of materials susceptible to selective leaching. Buried gray cast iron fire protection valves will be inspected opportunistically. In addition, when any buried gray cast iron valves are removed from the fire protection system, then specimens from at least one of them will be sent to a laboratory for metallurgical testing to determine the extent, if any, of selective leaching of the valve. A minimum of two metallurgical tests will be performed within the five years prior to entering the period of extended operation.

Enhancements

None

Operating Experience

The following discussion of operating experience provides objective evidence that the Selective Leaching program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation:

1. The Selective Leaching program is a new program for Callaway. Industry operating experience that forms the basis for this program is included in the operating experience element of the corresponding NUREG-1801 aging management program. Plant-specific operating experience was reviewed to ensure that the operating experience discussed in the corresponding NUREG-1801 aging management program is bounding, i.e., that there is no unique plant-specific operating experience in addition to that described in NUREG-1801. The Callaway Corrective Action Program was searched to determine if selective leaching has been identified for components with the applicable material and environment combinations. In addition, there are no copper alloy components with greater than eight percent aluminum within the scope of license renewal at Callaway.

No occurrences of selective leaching were found in a search of Callaway historical information. Occurrences that would be identified under the Selective Leaching 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 Selective Leaching 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 Selective Leaching 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.

B2.1.25 Buried and Underground Piping and Tanks

Program Description

The Buried and Underground Piping and Tanks program manages loss of material, cracking, blistering, and changes in color of external surfaces of buried and underground piping and tanks. The program augments other programs that manage the aging of internal surfaces of buried and underground piping and tanks. The materials managed by this program include steel, stainless steel and high-density polyethylene. The program manages aging through preventive, mitigative, and inspection activities.

Preventive and mitigative actions include the selection of component materials, external coatings for corrosion control, backfill quality control, and the application of cathodic protection. The cathodic protection system is operated consistent with the guidance of NACE SP0169-2007 for piping and NACE RP 0285-2002 for tanks. Trending of the cathodic protection system is performed to identify changes in the effectiveness of the system and to ensure that the rectifiers are available to protect buried components. An annual cathodic protection survey is performed consistent with NACE SP0169-2007.

Inspection activities may include ~~electrochemical verification of the effectiveness of cathodic protection~~, nondestructive evaluation of pipe and tank wall thicknesses, and visual inspections of pipe and tank exterior surfaces, as permitted by opportunistic or directed excavations. The fire protection system jockey pump is monitored to identify changes in jockey pump activity.

Direct visual inspections will be performed on buried steel, stainless steel, and high density polyethylene piping and carbon steel tanks. Inspection locations will be selected based on susceptibility to degradation and consequences of failure. A minimum of 10 feet of pipe of each material type must be inspected. The inspection will consist of a 100 percent visual inspection of the exposed pipe. If adverse indications are detected, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, further increases in inspection sample size would be based on an analysis of extent of cause and extent of condition. Visual inspections will be supplemented with surface or volumetric nondestructive testing (NDT) if significant indications are observed, to determine local area wall thickness.

Direct visual inspections will be performed on underground steel, stainless steel and high density polyethylene piping, tank access covers and valves to detect external corrosion. Inspection locations will be selected based on susceptibility to degradation and consequences of failure.

Inspections will begin during the 10-year period prior to entering the period of extended operation. Upon entering the period of extended operation, inspections will occur every 10 years.

The internal surfaces of buried and underground piping and tanks are managed through other programs. Internal surfaces may be managed by the Open-Cycle Cooling Water System (B2.1.10), Closed Treated Water Systems (B2.1.11), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23), Fuel Oil Chemistry (B2.1.16), Fire Water System (B2.1.14) or Water Chemistry (B2.1.2) programs. The Selective Leaching program (B2.1.19) works in conjunction with this program to manage buried or underground components subject to selective leaching.

NUREG-1801 Consistency

The Buried and Underground Piping and Tanks program is a new program that, when implemented, will be consistent with exception to NUREG-1801, Section XI.M41, *Buried and Underground Piping and Tanks*.

Exceptions to NUREG-1801

<u>Program Elements Affected:</u>

Preventive Actions (Element 2)

NUREG-1801, Section XI.M41, Table 2a, Note 6 states that for polymeric piping, backfill is acceptable if the inspections conducted by this program do not reveal evidence of mechanical damage to buried pipe coatings due to backfill. However the high-density polyethylene (HDPE) piping at Callaway is not coated, nor does NUREG-1801 Section XI.M41 Table 2a require HDPE piping to be coated. The HDPE piping at Callaway is backfilled with controlled low strength materials (flowable fill) that uses fine aggregate consistent with ASTM C33. NUREG-1801, Section XI.M41, Table 2a, Note 6 states that the use of flowable fill meets the backfill objectives of SP0169-2007.

Detection of Aging Effects (Element 4)

NUREG-1801, Section XI.M41.4.c.iv states that underground pipe shall be inspected by a volumetric technique such as UT to detect internal corrosion. As mentioned in the NUREG-1801 program description, other aging management programs are used to manage the internal surface of buried components. Therefore, ultrasonic testing of underground piping to detect internal corrosion is not included in this program.

NUREG-1801, Section XI.M41.4.f.iv states that if adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as necessary. If adverse indications are found in the expanded sample at Callaway, further increases in inspection sample size would be based on an analysis of extent of cause and extent of condition.

Enhancements

None

Operating Experience

The following discussion of operating experience provides objective evidence that the Buried and Underground Piping and Tanks 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 the winter of 2005, an alarm was triggered for fire protection loop jockey pump excessive run time and an investigation was initiated. The location of the leak was determined and promptly isolated from the main fire water loop. The isolation of the leak did not affect any required suppression systems. The leak was promptly repaired and the fire water piping was returned to service.
2. Prior to Refuel 15 (Spring 2007), Close Interval Surveys (CIS) were performed on various tanks and associated piping systems to identify cathodic protection effectiveness. The CIS testing measures cathodic protection levels along the pipeline at approximately 2.5 foot intervals. These surveys were performed on the following structures and components within the scope of license renewal: emergency fuel oil storage tanks, fire water storage tank bottoms, ESW system piping, and condensate storage tank piping. The results indicated that emergency fuel oil storage tanks, condensate storage tank piping, and one quadrant of the fire water storage tank, were not meeting the 850mV polarization potential criterion of the National Association of Corrosion Engineers (NACE). Corrective actions were taken to correct these deficiencies by adjusting the cathodic protection where possible. In some instances the cathodic protection system could not be adjusted to correct a condition. Cathodic protection system refurbishment and modifications are planned in areas where the system does not meet the NACE criteria.
3. From 2008 to 2009, the underground portions of the ESW supply from the ESW pump house and return to the ultimate heat sink cooling tower were replaced with 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.
4. In the summer of 2011, the annual cathodic protection survey was performed. Several locations in the fire water system had a negative potential below the NACE criteria of 850 mV. Modification and refurbishment of the cathodic protection system will address areas of low negative potential identified during the annual survey and the CIS described above.

5. Due to industry operating experience with buried condensate system piping, Callaway reviewed cathodic protection records related to the buried carbon steel piping for the condensate storage tank to determine if the external corrosion control provided for this piping was adequate. The review of the cathodic protection for this line found that the negative potential was below the NACE criteria. The cathodic protection system will be refurbished/modified in areas where it does not meet the NACE criteria. The buried portion of the condensate storage tank suction line will be inspected prior to the period of extended operation.

Inspection and preventive measures that will be implemented by the Buried and Underground Piping and Tanks program will be effective in managing aging of underground and buried components. Occurrences that would be identified under the Buried and Underground Piping and Tanks 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 Buried and Underground Piping and Tanks 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 Buried and Underground Piping and Tanks 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.