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PG&E Letter DCL-15-121

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to NRC Letter dated September 24, 2015, Request for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application – Set 38

Dear Commissioners and Staff:

By Pacific Gas and Electric Company (PG&E) Letter DCL-09-079, "License Renewal Application," dated November 23, 2009, PG&E submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for the renewal of Facility Operating Licenses DPR-80 and DPR-82, for Diablo Canyon Power Plant (DCPP) Units 1 and 2, respectively. The application included the License Renewal Application (LRA) and LRA Appendix E, "Applicant's Environmental Report – Operating License Renewal Stage."

By letter dated September 24, 2015, the NRC staff requested additional information needed to continue their review of the DCPP LRA.

Enclosure 1 contains PG&E's responses to the requests for additional information (RAIs). Enclosure 3 contains the affected LRA Amendment 50 pages resulting from the RAI responses with the changes shown as electronic markups (deletions crossed out and insertions italicized).

Enclosure 2 contains an update to the Buried Piping and Tanks Program licensing basis to address Draft LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations."

PG&E makes new regulatory commitments and changes to existing commitments (as defined by NEI 99-04) in this letter. New and revised commitments are contained in the changes to LRA Table A4-1 in Enclosure 3. A new regulatory commitment is provided in Enclosure 4.

If you have any questions regarding this response, please contact Mr. Terence L. Grebel, License Renewal Project Manager, at (805) 458-0534.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 21, 2015.

Sincerely,

Barry S. Allen
*Vice President – Nuclear Services*

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Enclosures
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**PG&E Response to NRC Letter dated September 24, 2015, Request for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application – Set 38 (TAC Nos. ME2896 and ME2897)**

*RAI 3.0.3.2.6-1*

*Background:*

*The annual update letter dated December 22, 2014, Enclosure 1, Attachment 7C, Exception 2, states an exception to conducting tests in accordance with NFPA 25 Section 6.3.1 "Flow Tests". The proposed alternative testing includes: (a) testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 every 5 years; (b) conducting a functional test on all of the in-scope hose stations every 3 years; and (c) opening a flushing connection or drain line at the end of branch lines in sprinkler piping during flow alarm testing in the auxiliary building and intake structure every 18 months. The proposed functional test includes "the absence of any indication of obstruction or other undue restriction of water flow," whereas testing for NFPA Section 6.3.1 verifies that "the water supply still provides the design pressure at the required flow" in the hydraulically most remote hose connection of each zone.*

*Issue:*

*It is not clear to the staff that the alternatives consisting of conducting a functional test on all of the in-scope hose stations every 3 years and opening a flushing connection or drain valve at the end of branch lines in sprinkler piping in the auxiliary building and intake structure include recording sufficient quantitative data to identify degraded performance or trends in the fire water system. In addition, there is no mention of opening drain connections for standpipe and sprinkler systems in the turbine building and radwaste storage facility. It is also not clear that testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 will provide assurance comparable to performing the test for each zone of the entire fire water system.*

*Request:*

*State the basis for why: (a) the alternative testing conducted in lieu of NFPA 25 Section 6.3.1 provides sufficient quantifiable data that is capable of being trended to detect degradation in the fire water system; and (b) testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 is sufficiently representative of the entire fire water system.*

PG&E Response to RAI 3.0.3.2.6-1

PG&E amends the response in Enclosure 1, Attachment 7C of PG&E Letter DCL-14-103, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 48 and LRA Appendix E, Applicant's

Environmental Report – Operating License Renewal Stage, Amendment 1," dated December 22, 2014, as follows. As described in PG&E Letter DCL-14-103, PG&E has an integrated fire water system that is not divided into zones. The system is a combined standpipe and sprinkler system where the results of flushing of the sprinkler branch lines is also indicative of the condition of the automatic standpipe system. Thus, instead of flow testing each "zone of the automatic standpipe system," PG&E will perform at least one NFPA (National Fire Protection Association) 25, Section 6.3.1 flow test in every major structure at the hydraulically most remote fire water hose stations (for a total of 13 flow tests). Instead of performing the flow tests of NFPA-25, Sections 6.3.1.5 and 13.2.5 annually, PG&E will perform the flow tests every 18 months.

Additional information regarding the fire water system and associated tests to be performed are discussed below:

(1) The 13 hydraulically most remote flow tests conducted in accordance with NFPA-25, Section 6.3.1 every 5 years will record and trend the static and residual pressure and flow rate. Pressure and flow rate trends will indicate whether the system is experiencing degradation such that it is capable of providing the design pressure at the required flow to the most hydraulically remote hose station locations. The hose station functional testing (conducted at least every three years) qualitatively verifies that the water supply is available and there is no indication of obstruction or other undue restriction of water flow. This functional testing applies to 86 in-scope hose stations throughout the turbine building, auxiliary building, containment buildings, and intake structure. The testing of branch lines at the end of sprinkler piping during flow alarm testing every 18 months demonstrates that the small bore sprinkler lines are free-flowing with no flow blockage. A combination of this quantitative and qualitative testing demonstrates the system is capable of providing fire water at design flow and pressure to all hose station locations, and that all hose station locations are functional and unobstructed.

(2) Although PG&E has an integrated fire water system that is not divided into zones, to determine how many flow tests should be conducted, each structure with in-scope hose stations was evaluated.

    (a) The turbine building is divided into two sections (Unit 1 and Unit 2) with four elevations per unit. PG&E will test a total of eight hydraulically remote hose stations in the turbine building to represent one hose station per elevation for each unit.

    (b) The auxiliary building (including the fuel handling buildings [FHBs]) is divided into two sections (Unit 1 and Unit 2). Flow in the radiologically-controlled areas increases the amount of liquid radwaste. To minimize the amount of liquid radwaste and sufficiently represent the fire water loop, PG&E will test a total of two hydraulically-remote hose stations in the auxiliary building to represent one hose station for each unit.

(c) The containment buildings are supplied from the auxiliary building and turbine building fire water loops. PG&E will test a total of two hydraulically-remote hose stations in the containment buildings to represent one hose station for each unit.

(d) PG&E will test a total of one hydraulically-remote hose station in the common intake structure.

The testing of 13 fire hose stations in accordance with NFPA 25 Section 6.3.1 is sufficiently representative of the entire fire water system because it is represents at least one hose station per major structure.

The above descriptions are summarized in the table below:

| DCPP Building | Components | Applicable NFPA Section(s) |
|---|---|---|
| Turbine building (TB) | • hose stations<br>• sprinkler systems<br>• four lead-ins | • Section 6.3.1 – PG&E proposes a combination of tests<br>o test eight hydraulically-remote hose stations in the TB (four per unit) every five years (record pressure/flow rate)<br>o functional test in-scope hose stations at least every 3 years (qualitative – verifies no obstructions)<br>o sprinkler branch line flushing every 18 months (qualitative – verifies no obstructions)<br>• Section 13.2.5 – PG&E takes exception to annual frequency (propose every 18 months)<br>o test all four system risers per Section 13.2.5 where the supply enters the TB (record pressure/flow rate) |
| Auxiliary building (AB) (including FHB) | • hose stations<br>• sprinkler systems<br>• two lead-ins | • Section 6.3.1 – PG&E proposes a combination of tests<br>o test two hydraulically remote hose stations in the AB (one per unit) every five years (record pressure/flow rate)<br>o functional test in-scope hose stations at least every 3 years (qualitative – verifies no obstructions)<br>o sprinkler branch line flushing every 18 months (qualitative – verifies no obstructions)<br>• Section 13.2.5 – PG&E takes exception to annual frequency and instead proposes every 18 months.<br>o test both system risers per Section 13.2.5 where the supply enters the AB (record pressure/flow rate) |

| DCPP Building | Components | Applicable NFPA Section(s) |
|---|---|---|
| Containment | • hose stations<br>• sprinkler systems<br>• supplied from AB | • Section 6.3.1 – PG&E proposes a combination of tests<br>o test one hydraulically remote hose station in each containment (total of two) every five years (record pressure/flow rate)<br>o functional test in-scope hose stations at least every 3 years (qualitative – verifies no obstructions)<br>o sprinkler branch line flushing every 18 months (qualitative – verifies no obstructions)<br>• Section 13.2.5 – PG&E takes exception to annual frequency and instead proposes every 18 months.<br>o test the system risers per Section 13.2.5 where the supply enters the AB and TB (record pressure/flow rate) |
| Radwaste building | • sprinkler system<br>• one lead-in<br>• no hose stations | • Section 13.2.5 – PG&E takes exception to annual frequency and instead proposes every 18 months.<br>o test the system riser per Section 13.2.5 where the supply enters radwaste building (record pressure/flow rate) |
| Intake structure | • hose stations<br>• sprinkler systems<br>• supplied by branch line off yard loop | • Section 6.3.1 – PG&E proposes a combination of tests<br>o test one hydraulically-remote hose station in the intake structure every five years (record pressure/flow rate)<br>o functional test in-scope hose stations at least every 3 years (qualitative – verifies no obstructions)<br>o sprinkler branch line flushing every 18 months (qualitative – verifies no obstructions)<br>• Section 13.2.5 – PG&E takes exception to annual frequency and instead proposes every 18 months.<br>o test the fire water supply for the intake structure at the fire hydrant outside the intake structure (record pressure/flow rate) |

*RAI 3.0.3.2.6-2*

*Background:*

*Annual update letter, dated December 22, 2014, Attachment 7C, Exception 5 for the Fire Water System program states that steel tanks will be inspected in accordance with NFPA-25, Section 9.2.6. However, it takes an exception to Section 9.2.6.4 by stating that any degradation will be entered into the corrective action program and an engineering evaluation will be performed to determine whether further actions are required. The update letter also states that the follow-up actions will be in accordance with either NFPA-25, Section 9.2.7 or Section 4.6.*

*NFPA-25, Section 9.2.6.4 states that tanks exhibiting signs of pitting, corrosion, or coating failure shall be tested in accordance with Section 9.2.7. NFPA-25, Section 9.2.7 states, "Where a drained interior inspection of a steel tank is required by 9.2.6.4, the following tests shall be conducted," then specifies six specific tests. NFPA-25, Section 4.6, "Performance-Based Programs," states that it provides an alternative means to comply with Section 4.5.2, "Frequency of Tests." It continues by stating that since its inception, NFPA-25 has included a provision allowing an alternative method of performing inspection, testing and maintenance, "but this provision does not detail exactly how such an alternative method should be implemented."*

*Issue:*

*It is unclear to the staff what criteria will be used to invoke the six tests specified in NFPA-25, Section 9.2.7 when degradation is exhibited on the interior of steel tanks, in accordance with Section 9.2.6.4. In addition, since Section 4.6 does not provide details on alternative inspection methods, it is unclear to the staff what alternative tests are being proposed to be conducted in lieu of those specified in Section 9.2.7.*

*Request:*

*State the basis and justify why entering degradation of the interior surface of steel tanks into the corrective action program will be sufficient to manage the effects of aging during the PEO when NFPA-25 states that testing shall be completed when degradation is noted.*

PG&E Response to RAI 3.0.3.2.6-2

As stated in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C, Exception 5, PG&E takes an exception to NFPA-25, Section 9.2.6.4 and proposes instead that any degradation found during inspections will be entered into the corrective action program (CAP) and an engineering evaluation will be performed to determine whether further actions are required. During fire water storage tank (FWST) inspections, degradation (holidays, corrosion, nodules, etc.) is documented via camera, nodule measurements and corrosion depth are recorded, and degradation findings are documented and trended in the CAP. Using the inspection documentation and recorded data, engineering evaluations will be conducted using the CAP to determine if augmented inspections are necessary or inspection intervals need to be changed (increased in frequency) to monitor degradation. If adverse wall thickness trends are identified during routine inspections such that minimum wall thickness is projected to be reached prior to the next schedule inspection (currently every 5 years), then the tank will be drained down, the 6 tests specified in NFPA-25, Section 9.2.7 will be performed, corroded base metal will be restored, and degraded coatings will be repaired.

Diablo Canyon Power Plant (DCPP) FWST operating experience and associated corrective actions provide further assurance that entering internal tank degradation into the CAP will be sufficient to manage the effects of aging. Following a 2006 periodic

internal inspection of the FWST, the resulting engineering evaluation, completed through the CAP, concluded that the corrosion internal to the fire water tank was a significant long-term aging issue. The FWST was drained down, all degradation was located and characterized, the bottom wall thickness was measured, and the tank was weld repaired and recoated. The FWST coating and base metal functioned adequately for more than 30 years prior to requiring refurbishment. In 2008, the original fire water source was replaced with high quality reverse osmosis water with chemistry controls (including pH controls to limit corrosion potential). Based on this operating experience and a chemistry-controlled water source, newly applied coatings and weld repairs are expected to maintain the intended functions by using a combination of the current CAP, the criteria for changing inspection frequency, and when necessary, performing the 6 tests in NFPA-25, Section 9.2.7 through the period of extended operation.

*RAI 3.0.3.2.6-3*

*Background:*

*Annual update letter dated December 22, 2014, Attachment 7C, Exception 6 for the Fire Water System program, states that inspection frequencies may be adjusted based on testing and inspection results, in accordance with NFPA-25, Section 4.6.*

*Issue:*

*Although NFPA-25, Section 4.6, "Performance-Based Programs," allows adjustments to inspection frequencies, as noted in Section A.4.6, a performance-based program requires that a maximum allowable failure rate be established and approved by the authority having jurisdiction in advance of implementation. In addition, a formal process for reviewing failure rates and making adjustments to test frequencies must be documented and have concurrence from the authority having jurisdiction prior to any changes to the test program. Furthermore, adjusted frequencies must be technically defensible and supported by evidence of reliability, and data collection and retention must be established so that data used to alter frequencies are representative, statistically valid, and evaluated against firm criteria. Without the details relating to the proposed maximum allowable failure rate and the formal process for reviewing and making adjustments, the staff has insufficient information to evaluate this exception.*

*Request:*

*Provide details, as discussed in NFPA-25, Section 4.6, "Performance-Based Programs," for all aspects related to adjusting inspection or test frequencies based on past data. Alternatively, propose exceptions to specific inspection frequencies and provide the bases to justify the change to these frequencies.*

PG&E Response to RAI 3.0.3.2.6-3

PG&E will enhance the Fire Water System Program (B2.1.13) to revise plant procedures to document the process for using performance-based monitoring (testing, maintenance, inspection, consequence of system maloperation). Prior to making any changes to inspection/test frequencies, PG&E will establish a maximum allowable failure rate, and proceduralize a process for reviewing failure rates and making adjustments to inspection/test intervals. The process will be technically defensible to Nuclear Electric Insurance Limited (NEIL), the authority having jurisdiction, and supported by evidence of higher or lower reliability. Test/inspection results data utilized for establishing reliability metrics will be statistically valid, evaluated against firm criteria, and retained for reference. Concurrence of NEIL will be obtained on the process used to determine test/inspection frequencies, and the maximum allowable failure rate, in advance of any alternations to the test/inspection program. The procedure will contain a formalized method of increasing or decreasing the frequency of testing/inspection when systems exhibit either a higher than expected failure rate or an increase in reliability as a result of a decrease in failures, or both. The justification for changing the interval will be documented using the CAP, and referenced in the revision history for the implementing inspection/testing procedure.

The inspections/testing intervals of the Fire Water System Program will be determined by a performance based approach as allowed in NFPA-25, Section 4.6, "Performance-Based Programs." The minimum inspection/testing interval (the interval approved in the DCPP Fire Water System Program) may be extended when acceptable performance is established. Acceptable performance is defined as "as found" inspections/testing where the number of instances the acceptance criteria is not met does not exceed the maximum allowable failure rate approved in advance by NEIL. NEIL has provided the period of time over which the previous results should be reviewed to establish the failure rate. The period of time is dependent on the revised interval of testing/inspection. The NEIL recommendations are documented in Section 11.2.1.1 of Electric Power Research Institute (EPRI) 1006756, July 2003, Implementation Guidelines for a Performance-Based Surveillance Program. Those intervals are shown in the table below.

| Minimum Recent Data Collection Period for Expanding Test/Inspection Intervals | |
|---|---|
| **Test/Inspection Frequency** | **Required Data** |
| Up to quarterly | 2 years of most recent data |
| Quarterly up to annual | 3 years of most recent data |
| Annual up to fuel cycle | 5 years of most recent data |
| Fuel cycle or longer | Extension currently not permitted |

When an equipment failure occurs, it is entered into the CAP, trended, and an engineering evaluation is performed. Resulting corrective actions are taken based on the cause of the problem. Test results would be evaluated upon completion of each test scoped in the program to ensure compliance with the established performance based criteria. If the maximum allowable failure rate is exceeded during the required data interval, the inspection/test interval will be adjusted in accordance with NEIL approved method for increasing inspection/test frequency. Once cause determination and corrective actions have been completed, acceptable performance may be re-established.

*RAI 3.0.3.2.6-4*

*Background:*

*The annual update letter dated December 22, 2014, revises LRA Section A1.13. The revised LRA Section A1.13 does not address whether the fire water system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.*

*SRP-LR Table 3-0-1, as modified by LR-ISG-2012-02 states that the water-based 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.*

*Issue:*

*LRA Section A1.13 is not consistent with SRP-LR Table 3-0-1, as modified by LR-ISG-2012-02 and a basis was not provided.*

*Request:*

*State the basis for not including a statement that the fire water system will be normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated in the licensing basis for the period of extended operation.*

PG&E Response to RAI 3.0.3.2.6-4

License Renewal Application (LRA), Section A1.13 is amended as shown in Enclosure 3 to include a discussion of maintaining required operating pressure consistent with the recommendations in SRP-LR Table 3.0.1, as modified by LR-ISG-2012-02.

*RAI 3.1.2.2.3.1-1*

*Background:*

*By letter dated December 23, 2013 (PG&E Letter DCL-13-119), the applicant submitted its 10 CFR 54.21(b) annual update to its LRA. In this annual update, the applicant deleted a paragraph of LRA further evaluation Section 3.1.2.2.3.1, "Loss of Fracture Toughness due to Neutron Irradiation Embrittlement TLAA." This paragraph discussed the applicant's pressurized thermal shock implementation for the Unit 1 reactor vessel. The applicant has also submitted annual updates to its LRA by letters dated December 20, 2011 (PG&E Letter DCL-12-124), and December 21, 2011 (PG&E Letter DCL-11-136).*

*Issue:*

*The staff is unclear why the applicant deleted this paragraph of the LRA further evaluation Section 3.1.2.2.3.1. In its annual updates to the LRA, the applicant has provided updated time limited aging analyses (TLAAs) associated with its neutron fluence pressurized thermal shock and upper shelf energy analyses for Units 1 and 2.*

*Request:*

*Justify why this paragraph in LRA Section 3.1.2.2.3.1 was deleted from the LRA. Otherwise, clarify how further evaluation of loss of fracture toughness due to neutron embrittlement, is addressed regarding the updated Pressurized Thermal Shock and Upper Shelf Energy TLAAs for Diablo Canyon Units 1 and 2.*

PG&E Response to RAI 3.1.2.2.3.1-1

The subject paragraph in LRA, Section 3.1.2.2.3.1 was deleted to reflect the updated pressurized thermal shock analyses results that were submitted in PG&E Letter DCL-11-136, "10 CFR 54.21(b) Annual Update to the DCPP License Renewal Application and License Renewal Application Amendment Number 45," dated December 21, 2011. As discussed in PG&E Letter DCL-11-136, Enclosure 2 (amended LRA, Section 4.2.2), using the updated pressurized thermal shock analyses results, $RT_{PTS}$ for Unit 1 was projected to the end of the period of extended operation and remains within acceptable values. Thus, PG&E no longer requires implementation of 10 CFR 50.61a for the period of extended operation.

PG&E amends LRA, Section 3.1.2.2.3.1, as shown in Enclosure 3 to show that the remaining language is applicable to both Units 1 and 2. The Enclosure also identifies the information that was retained but not shown in PG&E Letter DCL-13-119, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application and License Renewal Application Amendment Number 47," dated December 23, 2013.

*RAI 3.4.2.3.1-1*

*Background:*

*As amended by letter dated February 25, 2015, LRA Table 3.4.2-1 states that internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid will be managed for loss of coating integrity by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H.LRA Table 3.4.2-1 does not describe the sulfuric acid environment or state the material of the coating/lining.*

*GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."*

*Issue:*

*GALL Report AMP XI.M42 does not identify sulfuric acid or any other acidic/caustic chemical environments as within the scope of the program. The periodicity of inspections stated in Table 4a of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water, raw water). The staff lacks sufficient information to evaluate the applicant's claim that internally coated/lined carbon steel exposed to sulfuric acid can be managed through its Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given that information on the coating material and environment was not provided.*

*Request:*

1. *Describe the operational environment of internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid in the Turbine Steam Supply System, identifying at a minimum: temperature, sulfuric acid concentration, and flow rate.*

2. *Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid in the Turbine Steam Supply System.*

3. *Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function will be maintained.*

PG&E Response to RAI 3.4.2.3.1-1

The internally-lined carbon steel piping, valves, and tanks in the turbine steam supply system that could be exposed to sulfuric acid are part of the steam generator blowdown (SGBD) treatment demineralizer system. This system was designed to prevent contamination of the secondary system following a steam generator tube rupture or significant steam generator tube leak event. Thus, this system is not in service during normal plant operation. Were the system to be placed in operation, the sulfuric acid would most likely be in concentrations of between 4 to 96 percent, flowing up to 24.5 gpm, at ambient temperature while the demineralizers process secondary water at approximately 110°F for the period of time the SGBD demineralizers are in service. The linings used in the system are polypropylene, ethylene, fluorinated ethylene propylene, and semi-hard rubber. Because sulfuric acid would only be added if the system were to be placed in service in response to isolated events for limited periods of time, long-term aging effects of the coatings/liners are not expected.

The components associated with the SGBD treatment demineralizer system are no longer in service. They were assumed to contain fluid because they have not been formally abandoned in place. Because the components are not in service, the system normally contains demineralized water. Thus, the long-term internal environment is demineralized water, not sulfuric acid.

PG&E evaluated the six criteria listed in LR-ISG-2013-01, Appendix C, "Aging Management Program XI.M42 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks, Element 4," for inspection alternatives for the SGBD treatment demineralizer system and determined that all six criteria are met. Therefore, PG&E is revising the licensing basis in Enclosure 1 of PG&E Letter DCL-15-027, "Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 49 and LRA Appendix E, 'Applicant's Environmental Report – Operating License Renewal Stage,' Amendment 2," dated February 25, 2015, to manage aging of the SGBD treatment demineralizer system piping, piping components, and tanks using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22) and External Surfaces Monitoring program (B2.1.20) to ensure the intended function is maintained.

As shown in Enclosure 3, PG&E revises LRA Section A.1.42, Table A4-1, item 74, Section B2.1.42, and Table 3.4.2-1 to: (1) change the environment for lined components in the SGBD demineralizer system temporarily exposed to sulfuric acid from sulfuric acid to demineralized water; (2) manage loss of material of carbon steel piping, piping components, and tanks with liners exposed to demineralized water using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22); (3) remove the lines for piping, valves, and tanks with a material of carbon steel and an environment of sulfuric acid; and (4) revise a plant-specific note that is assigned to carbon steel piping, valves, and tanks with internal lining and an internal environment of demineralized water in the SGBD treatment demineralizer system to clarify that the components may temporarily be exposed to sulfuric acid, sodium

hydroxide, or secondary water at 110°F, but is exposed to demineralized water for the long-term and managed for loss of material using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22).

*RAI 3.4.2.3.1-2*

*Background:*

*As amended by letter dated February 25, 2015, LRA Table 3.4.2-1 states that loss of coating integrity for internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide will be managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H. LRA Table 3.4.2-1 does not describe the sodium hydroxide environment or state the material of the coating/lining.*

*GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."*

*Issue:*

*GALL Report AMP XI.M42 does not identify sodium hydroxide or any other acidic/caustic chemical environments as within the scope of the program. The periodicity of inspections stated in Table 4a, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water, raw water). The staff lacks sufficient information to evaluate the claim that loss of coating integrity for internally coated/lined carbon steel exposed to sodium hydroxide can be managed through the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given that information on the coating material and environment was not provided.*

*Request:*

1. *Describe the operational environment of internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide in the turbine steam supply system, identifying at a minimum: temperature and sodium hydroxide concentration.*

2. *Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide in the turbine steam supply system.*

3. *Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function of the internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide will be maintained.*

PG&E Response to RAI 3.4.2.3.1-2

The internally lined carbon steel piping, valves, and tanks in the turbine steam supply system that could be exposed to sodium hydroxide are part of the SGBD treatment demineralizer system. This system was designed to prevent contamination of the secondary system following a steam generator tube rupture or significant steam generator tube leak event. Thus, this system is not in service during normal plant operation. Were the system to be placed in service, the sodium hydroxide would most likely be in concentrations of up to 50 percent or 4 percent depending on the part of the system. The temperature of the 50 percent solution of sodium hydroxide would be controlled at 75°F to prevent solidification of the solution and the 4 percent solution would be close to ambient as it is a mixture of makeup water (demineralized/ treated water) and the 50 percent sodium hydroxide solution. While in operation, the demineralizers will process secondary water at approximately 110°F. If the system were to be placed in service, the 4 percent sodium hydroxide solution would only be present in the system for a maximum of 45 minutes twice a week and the 50 percent sodium hydroxide solution may be present in the system for the period of time the SGBD demineralizers are in service. The linings used in the system are polypropylene, ethylene, fluorinated ethylene propylene, and semi-hard rubber.

As described in the License Renewal Safety Evaluation Report, Section 3.3.2.3.5, dated June 2, 2011, the components associated with the SGBD treatment demineralizer system are no longer in service. They were assumed to contain fluid because they have not been formally abandoned in place. Because the components are not in service, the system normally contains demineralized water. Thus, the long-term internal environment is demineralized water, not sodium hydroxide. Because sodium hydroxide would only be added if the system were to be placed in service in response to isolated events for limited periods of time, the long-term internal environment is demineralized water, not sodium hydroxide, and long-term aging effects of the coatings/liners are not expected.

PG&E evaluated the six criteria listed in LR-ISG-2013-01, Appendix C, "Aging Management Program XI.M42 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks, Element 4," for inspection alternatives for the SGBD treatment demineralizer system and determined that all six criteria are met. Therefore, PG&E is revising the licensing basis in PG&E Letter DCL-15-027, Enclosure 1, to manage aging of the SGBD treatment demineralizer system piping, piping components, and tanks with internal lining with the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22) and External Surfaces Monitoring Program (B2.1.20) to ensure the intended function is maintained.

As shown in Enclosure 3, PG&E revises LRA Section A.1.42, Table A4-1, item 74, Section B2.1.42, and Table 3.4.2-1 to: (1) change the environment for lined components in the SGBD treatment demineralizer system temporarily exposed to sodium hydroxide from sodium hydroxide to demineralized water; (2) manage loss of material of carbon steel piping, piping components, and tanks with liners exposed to demineralized water using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22); (3) remove the lines for piping, valves, and tanks with a material of carbon steel and an environment of sodium hydroxide; and (4) revise a plant-specific note that is assigned to carbon steel piping, valves, and tanks with internal lining and an internal environment of demineralized water in the SGBD treatment demineralizer system to clarify that they may be temporarily exposed to sulfuric acid, sodium hydroxide, or secondary water at 110°F but is exposed to demineralized water for the long-term and managed for loss of material using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22).

*RAI 3.4.2.3.1-3*

*Background:*

*As amended by letter dated February 25, 2015, LRA Tables 3.4.2-1 and 3.4.2-4 state that loss of coating integrity for internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water will be managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H. LRA Table 3.0-1, "Mechanical Environments," defines secondary water as the following GALL Report environments: steam, treated water, treated water >60 °C, secondary feedwater/steam, and secondary feedwater.*

*GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."*

*Issue:*

*GALL Report AMP XI.M42 does not identify steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater, or any other high temperature environments as within the scope of the program. The periodicity of inspections stated in Table 4a of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water). The staff lacks sufficient information to evaluate the claim that loss of coating integrity for internally coated/lined carbon steel exposed to steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater or any other high temperature environments can be managed through the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given*

*that information on the coating material and GALL Report environment was not provided.*

*Request:*

1. *Identify the GALL Report environments for internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems. Complete the additional requests below for each GALL Report environment not listed in the AMP XI.M42 "scope of program" program element (e.g., steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater).*

2. *Identify the temperature of internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems for each GALL Report environment not listed in AMP XI.M42.*

3. *Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems for each GALL Report environment not listed in AMP XI.M42.*

4. *Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function of the internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water will be maintained for each GALL Report environment not listed in AMP XI.M42.*

PG&E Response to RAI 3.4.2.3.1-3

The internally-lined carbon steel piping, valves, and tanks in the turbine steam supply system that could be exposed to secondary water are part of the SGBD treatment demineralizer system. This system was designed to prevent contamination of the secondary system following a steam generator tube rupture or significant steam generator tube leak event. Thus, this system is not in service during normal plant operation. Were the system to be placed in service, the DCPP Final Safety Analysis Report (FSAR) Update, Revision 22, indicates that before entering the SGBD demineralizers, the temperature of the blowdown (secondary water) is reduced to approximately 110°F (43°C). The secondary water would only be present in the SGBD treatment demineralizer system during the period of time the system was in service. The linings used in the system are polypropylene, ethylene, fluorinated ethylene propylene, and semi-hard rubber.

The components associated with the SGBD treatment demineralizer system are no longer in service. They were assumed to contain fluid because they have not been formally abandoned in place. Because the components are not in service, the system

normally contains demineralized water. Thus, the long-term internal environment is demineralized water, not secondary water. The system would only be subjected to secondary water if the system were used in the event of a steam generator tube leak. Because secondary water would only be added if the system were to be placed in service in response to isolated events for limited periods of time, the long-term internal environment is demineralized water, not secondary water, and long-term aging effects of the coatings/liners are not expected.

PG&E evaluated the six criteria listed in LR-ISG-2013-01, Appendix C, Aging Management Program XI.M42 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks, Element 4, for inspection alternatives for the SGBD treatment demineralizer system and determined that all six criteria are met. Therefore, PG&E is revising the licensing basis in PG&E Letter DCL-15-027, Enclosure 1, to manage aging of the SGBD treatment demineralizer system piping, piping components, and tanks with internal lining with the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22) and External Surfaces Monitoring Program (B2.1.20) to ensure the intended function is maintained.

As shown in Enclosure 3, PG&E revises LRA Section A.1.42, Table A4-1, item 74, Section B2.1.42, and Table 3.4.2-1 to: (1) change the environment for lined components in the SGBD treatment demineralizer system temporarily exposed to secondary water from secondary water to demineralized water; (2) manage loss of material of carbon steel piping, piping components, and tanks with liners exposed to demineralized water using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22); and (3) revise a plant-specific note that is assigned to carbon steel piping, valves, and tanks with internal lining and an internal environment of demineralized water in the SGBD treatment demineralizer system that they may be temporarily exposed to sulfuric acid, sodium hydroxide, or secondary water at 110°F but is exposed to demineralized water for the long-term and managed for loss of material with using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program (B2.1.22).

*RAI 4.2.1-1*

*Background:*

*Attachment 2 of the applicant's 2011 annual update (December 21, 2011) indicates that a neutron fluence assessment of the beltline and extended beltline regions through the period of extended operation was performed by Westinghouse in WCAP-17299-NP, "Fast Neutron Fluence Update for Diablo Canyon Unit 1 and Unit 2 Pressure Vessels," Revision 0, February 2011.*

*In the following reference, the applicant indicated that its methods used to develop the calculated reactor vessel fluence are consistent with the NRC-approved methodology described in WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure*

*Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," Revision 2, January 1996.*

- *WCAP-15985, Revision 0, "Analysis of Capsule V from Pacific Gas and Electric Company Diablo Canyon Unit 1 Reactor Vessel Radiation Surveillance Program," January 2003 (ADAMS Accession No. ML031400342)*

*Issue:*

*The applicant did not clearly address whether the neutron fluence methodology used in WCAP-17299-NP, Revision 0 and the 2011 annual update is consistent with the methodology described in WCAP-14040-NP-A, Revision 2.*

*Request:*

*Clarify whether the neutron fluence calculational methodology used in WCAP-17299-NP, Revision 0 and the applicant's 2011 annual update is consistent with the methodology described in WCAP-14040-NP-A, Revision 2. If not, provide additional information to demonstrate that the applicant's fluence methodology adheres to Regulatory Guide 1.190.*

PG&E Response to RAI 4.2.1-1

The neutron fluence calculation methodology used in WCAP-17299-NP, Revision 0 and PG&E's 2011 annual update is consistent with the methodology described in WCAP-14040-NP-A, Revision 4. WCAP-14040-NP-A, Revision 4 fluence methodology adheres to NRC-approved Regulatory Guide (RG) 1.190.

*RAI 4.2.3-1*

*Background:*

*In Pacific Gas and Electric Company (PG&E) Letter DCL-11-136 (Dec. 21, 2011), the applicant provided an update of the upper shelf energy (USE) analysis for ferritic components in the reactor pressure vessels (RPVs) of Diablo Canyon, Units 1 and 2. The applicant stated that, in accordance with Regulatory Guide (RG) 1.99, Revision 2, the USE data from Unit 1 surveillance Capsule V were determined not to be credible and were, therefore, not included in the USE projections for Unit 1 RPV components represented in the Diablo Canyon RPV surveillance program for Unit 1. Instead, the applicant stated that the USE values were projected to 54 effective full power years (EFPY) of operation using USE analysis methods and criteria that are given in Position 1.2 of RG 1.99, Revision 2.*

*Issue:*

*Page No. 1.99-2 in RG 1.99, Revision 2, establishes the following regulatory discussion regarding the application of Charpy-impact data for neutron fluence-dependent RPV adjusted reference temperature calculations and USE analyses:*

> *When there are two or more sets of surveillance data from one reactor, the scatter of $\Delta RT_{NDT}$ values about a best-fit line drawn as described in Regulatory Position 2.1 normally should be less than 28 °F for welds and 17 °F for base metal. Even if the fluence range is large (two or more orders of magnitude), the scatter should not exceed twice those values. Even if the data fail this criterion for use in . . . [$\Delta RT_{NDT}$] . . . shift calculations, they may be credible for determining decrease in upper-shelf energy if the upper shelf can be clearly determined, following the definition given in ASTM E185-82.*

*The staff seeks further justification why all capsule data (i.e., those from the Capsule S, Y, and V Charpy-impact tests of materials representing Weld Heat 27204 in the Unit 1 RPV material surveillance program) have not been applied to the 54 EFPY USE analyses for RPV weld components in Unit 1 fabricated from the same weld heat.*

*Request:*

*Justify why all capsule data (i.e., those from the Capsule S, Y, and V Charpy-impact test specimens for Weld Heat 27204 in the Unit 1 reactor vessel material surveillance program as reported and analyzed in WCAP-15958, Rev. 0) have not been used as the basis for calculating the 54 EFPY USE values for Unit 1 RPV weld components fabricated from the same weld heat (i.e., for the USE calculations of intermediate shell axial welds 2-442 A, B and C, and lower shell axial welds 3-442, A, B, and C).*

PG&E Response to RAI 4.2.3-1

PG&E amends LRA, Section 4.2.3, as shown in Enclosure 3, to state that in accordance with RG 1.99, Revision 2, the $C_V$ USE data from Unit 1 surveillance Capsule V were determined not to be credible for determination of $\Delta RT_{NDT}$, but were credible for determining the USE projections for Unit 1 RPV components represented in the DCPP RPV surveillance program for Unit 1.

RG 1.99, Revision 2 defines two methods that can be used to predict the decrease in USE due to irradiation. The method to be used depends on the availability of credible surveillance capsule data. For vessel beltline materials that are not in the surveillance program or are not credible, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in RG 1.99, Revision 2.

When two or more credible surveillance data sets become available from the reactor vessel, they may be used to determine the Charpy USE of the surveillance materials.

The surveillance data are then used in conjunction with Figure 2 of the RG to predict the decrease in USE (Position 2.2) of the reactor vessel materials due to irradiation. If the end-of-license and/or end-of-license extended USE values calculated using Position 2.2 are most limiting, then they must be used regardless of the credibility of the surveillance data.

Unit 1 USE values were projected to 54 EFPY of operation using Position 1.2 results because they were more limiting than the Position 2.2 results.

*RAI 4.2.2-4*

*Background:*

*In PG&E Letter DCL-11-136 (Dec. 21, 2011), the applicant provided an update of the pressurized thermal shock (PTS) analysis for ferritic components in the RPVs of Diablo Canyon, Units 1 and 2.*

*Issue 1:*

*The staff performed independent PTS calculations for the Unit 1 RPV beltline and extended beltline components (54 EFPY) and has verified that all ferritic components in the beltline and extended beltline regions of the Unit 1 RPV will satisfy the PTS screening criteria for the components through 60 years of licensed operations (i.e., through 54 EFPY). However, some of the analysis parameter values independently calculated by the staff differ from those reported for $RT_{PTS}$ assessment parameters in license renewal application (LRA) Table 4.2-4 for Unit 1 or in LRA Table 4.2-5 for Unit 2.*

*Request 1:*

a) *Margin term values for Unit 1 RPV upper shell plates B4105-1 (Heat No. C2824-1) and B4105-2 (Heat No. C2824-2): Provide the $\sigma_U$ and $\sigma_\Delta$ values used to calculate the margin term value for the $RT_{PTS}$ calculation and the basis for reporting a margin term value of 39.2 °F for these components.*

b) *Margin term values for Unit 1 RPV upper shell plate B4105-3 (Heat No. C2608-2B): Provide the $\sigma_U$ and $\sigma_\Delta$ values used to calculate the margin term value for the $RT_{PTS}$ calculation and the basis for reporting a margin term value of 41.2 °F for these components.*

c) *Margin term values for Unit 1 RPV intermediate shell axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204): Provide the $\sigma_U$ and $\sigma_\Delta$ values used to calculate the margin term value for the $RT_{PTS}$ calculation and the basis for reporting the margin term value of 44.0 °F for these components.*

d) *Chemistry factor values for Unit 1 RPV intermediate shell axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204): Provide the basis for reporting a chemistry factor of 214.1 °F for these components.*

e) *Chemistry factor values for Unit 2 RPV upper shell axial welds 1-201 A, B, and C, and intermediate shell axial welds 2-201 A, B, and C (all made from Tandem Heat 21935/12008): Provide the basis for reporting a chemistry factor of 204.6 °F for these components.*

f) *Provide the methodology basis (i.e., plant-specific, generic, NRC-generic, MTEB 5-2, etc.) of the $RT_{NDT(U)}$ value that was reported for each RPV beltline or extended beltline component referenced in LRA Table 4.2-4 and in LRA Table 4.2-5.*

*Issue 2:*

*In the revision of LRA Table 4.2-5 for Unit 2 PTS analysis, the applicant provided additional $RT_{PTS}$ calculations for the Unit 2 RPV lower shell axial welds 3-201 A, B, and C (Weld Heat No. 33A277) using surveillance data from Pressurized Water Reactor (PWR) RPV surveillance programs other than the programs for the Diablo Canyon units. Although this weld heat is not represented in any of the capsules in the Unit 2 RPV material surveillance program, the staff has determined the Charpy-impact weld test specimens for welds made from Weld Heat No. 33A277 were included in the RPV surveillance program for Farley Unit 1 (a Westinghouse unit), as well as those for Calvert Cliffs Unit 1 and Unit 2 (both are CE units). This weld heat is also included in the RPV surveillance programs for some U.S. boiling water reactors.*

*Request 2:*

*Identify and justify which of the sister plant RPV surveillance programs have been used as the sources of the surveillance data for the $RT_{PTS}$ values for Unit 2 RPV lower shell axial welds 3-201 A, B, and C (as made from Weld Heat No. 33A277) and which of the capsule reports from these are being used as the source of the surveillance data for these welds. Clarify whether there are any plant-specific operational condition differences of note (e.g., differences in operating temperatures for the sister plant units from Diablo Canyon Unit 2) that would need to be identified and factored into the $RT_{PTS}$ calculations for Unit 2 RPV lower shell axial welds 3-201 A, B, and C. If so, clarify how the differences in the operational characteristics have been factored into the $RT_{PTS}$ calculations for Unit 2 RPV lower shell axial welds 3-201 A, B, and C.*

PG&E Response to RAI 4.2.2-4

Request 1:

(a) Margin term values for Unit 1 RPV upper shell plates B4105-1 (Heat No. C2824-1) and B4105-2 (Heat No. C2824-2) are:

| Reactor Vessel Material | $\sigma_U$ (1) | $\sigma_\Delta$ (2) |
|---|---|---|
| B4105-1 (Heat No. C2824-1) | 17 | 9.7 |
| B4105-2 (Heat No. C2824-2) | 17 | 9.7 |

(1) Initial $RT_{NDT}$ values are either generic or estimated; therefore, $\sigma_U$ = 17°F.
(2) $\sigma_\Delta$ need not exceed 0.50 times $\Delta RT_{NDT}$. Since $\Delta RT_{NDT}$ = 19.4°F for Upper Shelf Plate B4105-1 and 19.5°F for Upper Shelf Plate B4105-2 (see LRA Table 4.2-4), then $\sigma_\Delta$ = 9.7°F.

The margin term value of 39.2°F was calculated using the following equation:

$$Margin(^oF) = 2\sqrt{\sigma_U^{\ 2} + \sigma_\Delta^{\ 2}} = 2\sqrt{17^2 + 9.7^2} = 39.2(^oF)$$

(b) Margin term values for Unit 1 RPV upper shell plate B4105-3 (Heat No. C2608-2B) are:

| Reactor Vessel Material | $\sigma_U$ (1) | $\sigma_\Delta$ (2) |
|---|---|---|
| B4105-3 (Heat No. C2608-2B) | 17 | 11.6 |

(1) Initial $RT_{NDT}$ values are either generic or estimated; therefore, $\sigma_U$ = 17°F.
(2) $\sigma_\Delta$ need not exceed 0.50 times $\Delta RT_{NDT}$. Since $\Delta RT_{NDT}$ = 23.2°F for Upper Shelf Plate B4105-3 (see LRA Table 4.2-4), then $\sigma_\Delta$ = 11.6°F.

The margin term value of 41.2°F was calculated using the following equation:

$$Margin(^oF) = 2\sqrt{\sigma_U^{\ 2} + \sigma_\Delta^{\ 2}} = 2\sqrt{17^2 + 11.6^2} = 41.2(^oF)$$

(c) Margin term values for Unit 1 RPV intermediate shell (IS) axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204) are:

| Reactor Vessel Material | $\sigma_U$ (1) | $\sigma_\Delta$ (2) |
|---|---|---|
| IS axial weld 2-442A | 17 | 14 |
| IS axial weld 2-442B | 17 | 14 |
| IS axial weld 2-442C | 17 | 14 |

(1) Initial $RT_{NDT}$ values are either generic or estimated; therefore, $\sigma_U$ = 17°F.
(2) Per the guidance of 10 CFR 50.61, with credible surveillance data $\sigma_\Delta$ = 14°F for Position 2.1.

The margin term value of 44°F was calculated using the following equation:

$$Margin(^{o}F) = 2\sqrt{\sigma_U^{\ 2} + \sigma_\Delta^{\ 2}} = 2\sqrt{17^2 + 14^2} = 44.0(^{o}F)$$

(d) Chemistry factor values for Unit 1 RPV IS axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204) were reported as 214.1°F. These values were calculated using available surveillance data as shown below:

| Material | Capsule | Capsule f (1) ($x10^{19}$ $n/cm^2$, E>1.0MeV) | FF (2) | $\Delta RT_{NDT}$ (3) (°F) | FF* $\Delta RT_{NDT}$ (°F) | $FF^2$ |
|---|---|---|---|---|---|---|
| Weld Metal Heat No. 27204 (DCPP Unit 1 data) | S | 0.283 | 0.655 | 119.13 (110.79) | 78.06 | 0.429 |
| | Y | 1.05 | 1.014 | 241.53 (232.59) | 244.82 | 1.027 |
| | V | 1.36 | 1.085 | 208.66 (201.07) | 226.49 | 1.178 |
| Weld Metal Heat No. 27204 (Palisades data) | SA-60-1 | 1.50 | 1.112 | 250.10 (253.1) | 278.18 | 1.237 |
| | SA-240-1 | 2.38 | 1.234 | 265.50 (267.8) | 327.59 | 1.522 |
| | | | | SUM: | 1155.14 | 5.395 |

(1) f = fluence
(2) FF = fluence factor = $f^{(0.28-0.10*\log f)}$
(3) $\Delta RT_{NDT}$ values are the measured 30 ft-lb shift values. The DCPP Unit 1 $\Delta RT_{NDT}$ values have been adjusted according to the temperature adjustment (temperature adjustment = $1.0*(T_{capsule} - T_{plant})$, where $T_{plant}$ = 538°F for DCPP Unit 1). Then, the DCPP Unit 1 $\Delta RT_{NDT}$ values for the surveillance weld data are adjusted by a ratio of 1.02 (pre-adjusted values are listed in parentheses). Ratio = $CF_{Vessel\ Weld} / CF_{Surv.\ Weld}$ = 226.8°F / 222.3°F = 1.02.

Palisades surveillance weld $\Delta RT_{NDT}$ values have been adjusted according to the temperature adjustments (temperature adjustment = $1.0*(T_{capsule} - T_{plant})$, where $T_{plant}$ = 538°F for DCPP Unit 1 also applied to Palisades data) (pre-adjusted values are listed in parentheses). No ratio is applied since the ratio was calculated to be 1.00. Ratio = $CF_{Vessel\ Weld} / CF_{Surv.\ Weld}$ = 226.8°F / 227.8°F = 1.00.

$$CF_{Heat\ \#\ 27204} = \Sigma(FF * \Delta RT_{NDT}) \div \Sigma(FF^2) = (1155.14) \div (5.395) = 214.1°F$$

(e) Chemistry factor value for Unit 2 RPV upper shell axial welds 1-201 A, B, and C, and intermediate shell axial welds 2-201 A, B, and C (all made from Tandem Heat 21935/12008) were reported as 204.6°F, based on RG 1.99, Revision 2, Position 2.1. These values were calculated using available surveillance data as shown below:

| Material | Capsule | Capsule f (1) ($x10^{19}$ $n/cm^2$, E>1.0MeV) | FF (2) | $\Delta RT_{NDT}$ (3) (°F) | FF* $\Delta RT_{NDT}$ (°F) | $FF^2$ |
|---|---|---|---|---|---|---|
| Weld Metal Heat No. 21935/12008 (DCPP Unit 2 data) | U | 0.330 | 0.695 | 180.0 (173.0) | 125.10 | 0.483 |
| | X | 0.906 | 0.972 | 210.2 (203.2) | 204.38 | 0.945 |
| | Y | 1.53 | 1.118 | 218.4 (211.4) | 244.09 | 1.249 |
| | V | 2.38 | 1.234 | 231.5 (224.5) | 285.64 | 1.522 |
| | | | | SUM: | 859.22 | 4.200 |

(1) f = fluence
(2) FF = fluence factor = $f^{(0.28-0.10*\log f)}$
(3) $\Delta RT_{NDT}$ values are the measured 30 ft-lb shift values. The DCPP Unit 2 $\Delta RT_{NDT}$ values have been adjusted according to the temperature adjustment (temperature adjustment = $1.0*(T_{capsule} - T_{plant})$, where $T_{plant}$ = 538°F for DCPP Unit 2). Pre-adjusted values are listed in parentheses. No ratio is applied to the $\Delta RT_{NDT}$ values for the surveillance weld data since the beltline weld and surveillance weld chemistry factors are identical.

$$CF_{\text{Heat \# 21935/12008}} = \Sigma(FF * \Delta RT_{NDT}) \div \Sigma(FF^2) = (859.22) \div (4.200) = 204.6°F$$

The scatter of $\Delta RT_{NDT}$ values about the best-fit line, drawn as described in RG 1.99, Revision 2, Position 2.1, should be less than 28°F for weld metal. Three of the four surveillance data points fall within the +/- 1σ of 28°F scatter band for surveillance weld materials; therefore, the weld surveillance data for Heat # 21935/12008 was deemed credible.

(f) The methodology basis of the $RT_{NDT(U)}$ value that was reported for each RPV beltline or extended beltline component referenced in LRA Table 4.2-4 and in LRA Table 4.2-5 is provided below.

**Unit 1, LRA Table 4.2-4 Components**

| Material Description | | | Initial $RT_{NDT}$ °F | Methodology Basis for Initial $RT_{NDT}$ |
|---|---|---|---|---|
| Location | Heat No. | Type | | |
| Upper Shell Plate B4105-1 | C2624 | A 533B | 28 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |
| Upper Shell Plate B4105-2 | C2624-2 | A 533B | 9 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |

| Material Description | | | Initial $RT_{NDT}$ °F | Methodology Basis for Initial $RT_{NDT}$ |
|---|---|---|---|---|
| Location | Heat No. | Type | | |
| Upper Shell Plate B4105-3 | C2608-2B | A 533B | 14 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |
| Intermediate Shell Plate B4106-1 | C2884-1 | A 533B | -10 | Measured or estimated based on experimental data |
| Intermediate Shell Plate B4106-2 | C2854-2 | A 533B | -3 | Measured or estimated based on experimental data |
| Intermediate Shell Plate B4106-3 | C2793-1 | A 533B | 30 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |
| Lower Shell Plate B4107-1 | C3121-1 | A 533B | 15 | Measured or estimated based on experimental data |
| Lower Shell Plate B4107-2 | C3131-2 | A 533B | 20 | Measured or estimated based on experimental data |
| Lower Shell Plate B4107-3 | C3131-1 | A 533B | -22 | Measured or estimated based on experimental data |
| Upper Shell Long. Weld 1-442 A | 27204 / 12008 | Linde 1092 | -20 | Measured or estimated based on experimental data |
| Upper Shell Long. Weld 1-442 B | 27204 / 12008 | Linde 1092 | -20 | Measured or estimated based on experimental data |
| Upper Shell Long. Weld 1-442 C | 27204 / 12008 | Linde 1092 | -20 | Measured or estimated based on experimental data |
| Upper Shell to Intermediate Shell Circumferential Weld 8-442 | 13253 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Intermediate Shell Long. Welds 2-442A, B | 27204 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Intermediate Shell Long. Weld 2-442C | 27204 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Lower Shell Long. Welds 3-442A, B | 27204 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Lower Shell Long. Weld 3-442C | 27204 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Intermediate to Lower Shell Circumferential Weld 9-442 | 21935 | Linde 1092 | -56 | Generic or estimated based on DCPP FSAR Update |

## Unit 2, LRA Table 4.2-5 Components

| Material Description | | | Initial $RT_{NDT}$ °F | Methodology Basis for Initial $RT_{NDT}$ |
|---|---|---|---|---|
| Location | Heat No. | Type | | |
| Upper Shell Plate B5453-1 | C5162-1 | A 533B | 28 | Measured or estimated based on experimental data |
| Upper Shell Plate B5453-3 | C5162-2 | A 533B | 5 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |
| Upper Shell Plate B5011-1R | C4377-1 | A 533B | 0 | Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2 |
| Intermediate Shell Plate B5454-1 | C5161-1 | A 533B | 52 | Measured or estimated based on experimental data |
| Intermediate Shell Plate B5454-2 | C5168-2 | A 533B | 67 | Measured or estimated based on experimental data |
| Intermediate Shell Plate B5454-3 | C5161-2 | A 533B | 33 | Measured or estimated based on experimental data |
| Lower Shell Plate B5455-1 | C5175-1 | A 533B | -15 | Measured or estimated based on experimental data |
| Lower Shell Plate B5455-2 | C5175-2 | A 533B | 0 | Measured or estimated based on experimental data |
| Lower Shell Plate B5455-3 | C5176-1 | A 533B | 15 | Measured or estimated based on experimental data |

| Material Description | | | Initial $RT_{NDT}$ °F | Methodology Basis for Initial $RT_{NDT}$ |
|---|---|---|---|---|
| Location | Heat No. | Type | | |
| Upper Shell Long. Weld 1-201 A | 21935 / 12008 | Linde 1092 | -50 | Measured or estimated based on experimental data |
| Upper Shell Long. Weld 1-201 B | 21935 / 12008 | Linde 1092 | -50 | Measured or estimated based on experimental data |
| Upper Shell Long. Weld 1-201 C | 21935 / 12008 | Linde 1092 | -50 | Measured or estimated based on experimental data |
| Upper Shell to Intermediate Shell Circumferential Weld 8-201 | 21935 | Linde 1092 | -56 | Generic value per 10 CFR 50.61 |
| Intermediate Shell Long. Weld 2-201A | 2193 / 12008 | Linde 1092 | -50 | Generic value per 10 CFR 50.61 |
| Intermediate Shell Long. Weld 2-201B | 2193 / 12008 | Linde 1092 | -50 | Generic value per 10 CFR 50.61 |
| Intermediate Shell Long. Weld 2-201C | 2193 / 12008 | Linde 1092 | -50 | Generic value per 10 CFR 50.61 |
| Lower Shell Long. Weld 3-201A | 33A277 | Linde 124 | -56 | Generic value per 10 CFR 50.61 |
| Lower Shell Long. Weld 3-201B | 33A277 | Linde 124 | -56 | Generic value per 10 CFR 50.61 |
| Lower Shell Long. Weld 3-201C | 33A277 | Linde 124 | -56 | Generic value per 10 CFR 50.61 |
| Intermediate to Lower Shell Circumferential Weld 9-201 | 10120 | Linde 0091 | -56 | Generic value per 10 CFR 50.61 |

Request 2:

The Farley Unit 1 and Calvert Cliffs Unit 1 surveillance programs include Weld Heat No. 33A277, which is the same weld heat as the DCPP Unit 2 LS longitudinal welds. Thus, the Farley Unit 1 and Calvert Cliffs Unit 1 data were used in calculation of Position 2.1 chemistry factors for DCPP Unit 2 Weld Heat No. 33A277. Calvert Cliffs Unit 2 does not have Weld Heat No. 33A277 in its surveillance program. Therefore, no additional surveillance data needs to be considered beyond Farley Unit 1 and Calvert Cliffs Unit 1 data for Weld Heat No. 33A277. The Farley Unit 1 and Calvert Cliffs Unit 1 data and associated source documents are described below.

Temperature adjustments were made to sister plant $\Delta RT_{NDT}$ values to account for operational differences between the sister plants and DCPP. Sister plant $\Delta RT_{NDT}$ values were also adjusted to account for differences in the surveillance weld chemistry and the beltline weld chemistry. The adjusted values were used in the $RT_{PTS}$ calculations for Unit 2 RPV lower shell axial welds 3-201 A, B, and C and are provided below.

| Material | Capsule | Capsule Fluence ($x10^{19}$ $n/cm^2$, E>1.0MeV) | Measured 30 ft-lb Transition Temperature Shift (°F) (7) | Cu Wt. % | Ni Wt. % | Position 1.1 Chemistry Factor (°F) (4) | Inlet Temperature during Period of Irradiation (°F) (5) | Temperature Adjustment (°F) (6) |
|---|---|---|---|---|---|---|---|---|
| Weld Metal Heat No. 33A277 (Farley Unit 1 data)(1) | Y | 0.612 | 118.1 (66.9) | 0.14 | 78.1 | 78.1 | 544.00 | +6.00 |
| | U | 1.73 | 125.3 (75.1) | 0.14 | 78.1 | 78.1 | 540.25 | +2.25 |
| | X | 3.06 | 146.2 (87.4) | 0.14 | 78.1 | 78.1 | 540.86 | +2.86 |
| | W | 4.75 | 165.3 (98.3) | 0.14 | 78.1 | 78.1 | 541.75 | +3.75 |
| | V | 7.14 | 196.4 (117.5) | 0.14 | 78.1 | 78.1 | 541.72 | +3.72 |
| | Z | 8.47 | 189.4 (113.5) | 0.14 | 78.1 | 78.1 | 541.43 | +3.43 |
| Weld Metal Heat No. 33A277 (Calvert Cliffs Unit 1 data) | 263° (2) | 0.62 (5) | 73.1 (59) | 0.24 | 119.4 | 119.4 | 548.00 | +10.00 |
| | 97° (3) | 2.64 | 109.2 (93) | 0.24 | 119.4 | 119.4 | 548.00 | +10.00 |

(1) Farley Unit 1 surveillance weld metal Heat No. 33A277 data are taken from WCAP-16964-NP, "Analysis of Capsule Z from the Southern Nuclear Operating Company Joseph M. Farley Unit 1 Reactor Vessel Radiation Surveillance Program," dated October 2008, Tables 4-1 and 5-10.

(2) Capsule 263° data for Calvert Cliffs Unit 1 surveillance weld metal Heat No. 33A277 are taken from Tables 13 and 17 of BMI-1280, "Final Report on Calvert Cliffs Unit No. 1 Nuclear Plant Reactor Pressure Vessel Surveillance Program: Capsule 263," dated December 1980.

(3) All Capsule 97° data for Calvert Cliffs Unit 1 surveillance weld metal Heat No. 33A277 taken from Tables 3-2 and 7-3 of BAW-2160, "Analysis of Capsule 97° Baltimore Gas & Electric Company Calvert Cliffs Nuclear Power Plant Unit No. 1, dated June 1993.

(4) Position 1.1 chemistry factors were calculated using the Cu Wt. % and Ni Wt. % values listed and Table 1 of 10 CFR 50.61.

(5) Capsule fluence value for Calvert Cliffs Unit 1 Capsule 263° as well as inlet temperature values for each of the Farley Unit 1 and Calvert Cliffs Unit 1 surveillance capsules were obtained from Table 11-4 of the "Comprehensive Reactor Vessel Surveillance Program," Revision 5.

(6) Temperature adjustment = $1.0*(T_{capsule} - T_{plant})$, where $T_{plant}$ = 538°F for DCPP Unit 2 (applied to the Farley Unit 1 and Calvert Cliffs Unit 1 data).

(7) $\Delta RT_{NDT}$ values are the measured 30 ft-lb shift values. $\Delta RT_{NDT}$ values for the surveillance weld data are adjusted first by the difference in operating temperature [as described in note (5)], then adjusted by a ratio to account for differences in the surveillance weld chemistry and the beltline weld chemistry (pre-adjusted values are listed in parentheses). The ratios applied are as follows:

Farley Unit 1 Ratio = $CF_{Vessel\ Weld} / CF_{Surv.\ Weld}$ = 126.3°F / 78.1°F = 1.62

Calvert Cliffs Unit 1 Ratio = $CF_{Vessel\ Weld} / CF_{Surv.\ Weld}$ = 126.3°F / 119.4°F = 1.06

*RAI B2.1.9-2*

*Background:*

*Annual update letter, dated December 22, 2014, states that microbiologically-induced RIC was identified in the auxiliary saltwater (ASW) system, and that the Open-Cycle Cooling Water System program manages the aging effects associated with the system. The letter states that the program inspects the ASW piping every fourth refueling outage to verify the integrity of the plastic pipe-liner and to detect indications of corrosion of the base material.*

*As amended by LR-ISG-2012-02, SRP-LR added further evaluation Section 3.3.2.2.8, "Loss of Material Due to Recurring Internal Corrosion." The further evaluation states that RIC can result in the need to augment AMPs beyond the recommendations in the GALL Report and recommends that if recurring aging effects are identified, the applicant addresses the following five aspects:*

> *(a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

*Issue:*

*Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. While the staff's safety evaluation report (SER) previously concluded that the effects of aging will be adequately managed by this program, it is unclear to the staff whether the identification of RIC in the ASW system warrants augmented inspections by the Open-Cycle Cooling Water System program. It is also unclear to the staff whether prior internal corrosion occurrences resulted in any changes to the Open-Cycle Cooling Water System program, and whether the trend for internal corrosion occurrences in the ASW system is indicative of a program that adequately manages the effects of aging.*

*In addition, by letter dated February 25, 2015, the AMR items associated with loss of coating integrity for the carbon steel piping and valves with coating or lining in the ASW system were changed from the Open-Cycle Cooling Water System program to the*

*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. Consequently, it is unclear to the staff whether any aspects of the inspections for the ASW piping will be changed as allowed under the new program.*

*Request:*

*For the past occurrences which led to the identification of RIC in the ASW system, discuss what changes were made to Open Cycle Cooling Water System program and provide the bases to demonstrate that current program will adequately manage any recurring aging effects. Provide specific information relating to the adequacy of the "every fourth refueling outage" inspection frequency to verify the integrity of the plastic pipe-liner and to detect indications of corrosion of the base material. Include a discussion about the trend for internal corrosion occurrences in the ASW system to show that the program adequately manages the recurring aging effects. Also include information relating to the five specific further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8 if not covered in the preceding items.*

*For the current inspections of the plastic pipe-liner, provide details about the extent (i.e., 100 percent or sample (with the bases for the sampling process)), and criteria for increasing frequency or sample size (if appropriate). Discuss whether the change for managing the loss of coating integrity from the Open-Cycle Cooling Water System program to the new Coatings/Linings program will result in any changes to the types, extent, and frequency of inspections that pertain to RIC.*

PG&E Response to RAI B2.1.9-2

In response to LR-ISG-2012-02, Section A, PG&E performed an operating experience evaluation of the auxiliary saltwater (ASW) system to determine if recurring internal corrosion (RIC) was occurring. RIC (microbiologically-induced corrosion [MIC]) was identified as occurring in the Open Cycle Cooling Water (OCCW) System Program (B2.1.9). A conservative decision was made to identify the ASW system as having RIC. A subsequent detailed review of corrective action documents for the last 10 years has determined that, while MIC has occurred for components within the scope of the Closed Cycle Cooling Water (CCCW) System Program (B2.1.10) (specifically the service cooling water system), it has not occurred in the ASW system itself. Continuous chlorination and periodic system inspections have been used in the ASW system since 1992. Periodic inspections have not identified MIC in the ASW system. As described in SER Section 3.0.3.1.7 and the Audit Report Regarding the DCPP LRA, dated August 11, 2010, the NRC conducted an independent search of the plant-specific operating experience information to determine if PG&E had adequately incorporated and evaluated operating experience related to the CCCW System Program. During its review, the NRC found no operating experience to show that PG&E's program would not be effective in adequately managing aging effects during the period of extended operation.

The MIC that was identified as occurring in the service cooling water system (non safety-related) was addressed by changing the water chemistry controls. Subsequent inspections since changing the water chemistry have indicated that the corrective action was effective.

PG&E revises the licensing basis in the OCCW System Program and its LR-ISG-2012-02, Section A response as described in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7A to delete the discussion of the ASW system experiencing MIC or RIC. Because RIC is not applicable to the ASW system, the OCCW System Program and Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks Program inspections are adequate to manage loss of material and loss of coating integrity, respectively.

The ASW plastic pipe-liner (paraliner) is currently inspected in response to NRC Generic Letter (GL) 89-13. As discussed in PG&E Letter DCL-90-027, "Response to Generic Letter 89-13, 'Service Water System Problems Affecting Safety-Related Equipment,'" dated January 26, 1990, PG&E implemented procedures to establish a routine inspection and maintenance program for the ASW system to ensure that corrosion and protective coating failure do not impair the ASW system design basis function. The appropriate inspection interval was determined based on the documented initial inspection results, trending, and reevaluation based on subsequent inspections. Every fourth refueling outage (6-7 years), each unit's ASW system piping (intake and discharge) is visually inspected. This visual inspection currently utilizes a robotic crawler equipped with a high definition camera to internally inspect all accessible piping which is greater than 75 percent of the piping. A report is generated that compares any findings to previous inspections findings to monitor for new anomalies or changes in anomalies for trending. Together with an engineering evaluation of the data, recommendations are made for future inspections and or repairs. Fifteen years of operating experience has shown acceptable results based on a continuing engineering evaluation and trending of inspection results. Any inspection findings are repaired based on the results of the engineering evaluation. The most recent ASW inspections were completed in the Unit 1 sixteenth refueling outage (2010) and Unit 2 sixteenth refueling outage (2011). These results showed that the overall condition of the ASW piping and liner were in good condition.

Due to 15 years of operating experience with acceptable results, PG&E amends its LR-ISG-2013-01 response as described in PG&E Letter DCL-15-027, Enclosure 1 to take exception to LR-ISG-2013-01, Appendix C, Table 4a minimum inspection intervals. Inspection intervals for the ASW system paraliner will be adjusted based on periodic inspection findings, trending, and evaluation by a qualified coating specialist using LR-ISG-2013-01 acceptance criteria. Inspection intervals will not exceed every fourth refueling outage. As shown in Enclosure 3, PG&E revises LRA Sections A1.42 and B2.1.42.

*RAI B2.1.13-5*

*Background:*

*Annual update letter dated December 22, 2014, states that RIC was identified in carbon steel components exposed to raw water in the fire protection system. The Fire Water System program was revised to address the changes to GALL Report AMP XI.M27 "Fire Water System." The update letter states that Fire Water System program will be enhanced as described in SER Section 3.0.3.2.6 to perform additional volumetric examinations and visual inspections of above ground fire water system piping. In addition, the program will be revised to address the changes to GALL Report AMP XI.M27 made by LR-ISG-2012-02, Section C, and the following revisions are sufficient to manage RIC in the fire protection system:*

1. *Internal and external visual inspections are performed on accessible exposed portions of fire water piping during plant maintenance activities, or at least once every 18 months for external visual inspections, and every 5 years for internal visual inspections. Consistent with LR-ISG-2012-02, Section C.iii.b, volumetric examination will not be used in lieu of prescribed visual examinations of the internal surface of piping. The inspections detect loss of material due to corrosion, ensure that aging effects are managed, and detect surface irregularities that could indicate wall loss below nominal pipe wall thickness. When surface irregularities are detected, follow-up volumetric wall thickness examinations are performed.*

2. *Augmented volumetric wall thickness inspections are performed on 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect in each five-year interval prior to the PEO. The 20 percent of piping inspected in each 5-year interval shall be in different locations than previously inspected piping.*

*As amended by LR-ISG-2012-02, SRP-LR added further evaluation Section 3.3.2.2.8. The further evaluation recommends that if recurring aging effects are identified the applicant address the following five aspects:*

> *(a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

*Issue:*

*Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. It is unclear to the staff whether prior internal corrosion occurrences resulted in any changes to the Fire Water System program, and whether the trend for internal corrosion occurrences within the system is indicative of a program that adequately manages the effects of aging. It is also unclear to the staff how the update letter addresses the further evaluation criteria in SRP-LR Section 3.3.2.2.8. For example, the applicant states that augmented volumetric wall thickness measurements will be performed on 20 percent of the piping segments that cannot be drained or piping segments that allow water manage RIC. The staff notes that corrosion in the fire protection system will likely occur in areas that cannot be drained, but it is not possible for the staff to conclude that only performing augmented inspections on piping segments that cannot be drained will adequately address RIC. In addition, the applicant does not describe decision points where an increase in the frequency or severity of RIC would result in increased inspections. Furthermore, the staff noted in SER -Section 3.0.3.2.6 that the applicant will perform opportunistic inspections of buried piping when excavated; however, it is unclear to the staff how this inspection procedure will adequately manage RIC of buried components before loss of intended function (e.g., leaks) occurs.*

*Request:*

*For the past occurrences which led to the identification of RIC in the fire protection system, discuss what changes were made to Fire Water System program and provide the bases to demonstrate that current program will adequately manage any recurring aging effects. Include a discussion about the trend for internal corrosion occurrences in the fire protection system to show that the program adequately manages the recurring aging effects. Also include the five further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8.*

PG&E Response to RAI B2.1.13-5

DCPP fire protection system inspection and test results are evaluated and trended by engineering after performance of each test. The CAP is used to report, trend, and correct system leaks and degradation. Adverse trends are entered into the CAP for further evaluation and corrective actions. As stated in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7A, RIC was identified in carbon steel components exposed to raw water in the fire protection system, specifically the above ground portions of the system piping. In response to past occurrences of corrosion in the fire protection system, PG&E has taken several corrective actions, including:

1. Replacement of fire water piping susceptible to high corrosion with a corrosion-free material

2. Replacement of corroded fire water piping with new piping

3. Development of long-term plans for monitoring and replacement of corroded fire water piping that has not yet been replaced

4. Change in fire water quality. Historically, fire water had been provided by the onsite non-treated Diablo Creek, which contains corrosive water. In 2008, PG&E discontinued using Diablo Creek water and started using a less corrosive water source with proceduralized chemistry controls of the fire water supply.

The five SRP-LR further evaluation Section 3.3.2.2.8 items are addressed below:

(a) As discussed in the LR SER Section 3.0.3.2.6, PG&E conducts periodic flow testing and flushes to ensure the fire water system piping maintains its design function. As discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C, DCPP's Fire Water System program (B2.1.13) will be enhanced consistent with LR-ISG-2012-02 to perform internal visual inspections that are capable of detecting surface irregularities that could be indicative of wall loss below nominal pipe wall thickness due to corrosion and corrosion product deposition. Following detection of such irregularities, non-intrusive volumetric examinations will be performed to determine if wall thickness is within acceptable limits.

The current testing at DCPP is capable of verifying the system can perform as-designed, and the enhanced inspections will provide early indication if any degradation is occurring. This combination of tests and inspections is sufficient to detect RIC prior to loss of intended function.

(b) Augmented inspections are not necessary for the DCPP fire water system piping that has previously experienced RIC because of the corrective actions described above. In addition to piping replacement, water to the fire water system is now high quality reverse osmosis water with chemistry controls in place (including pH controls to limit corrosion potential in the firewater system) to mitigate against corrosion. Follow-up inspections that have been conducted since implementation of the corrective actions demonstrate the adequacy of the corrective actions, such as fire pump performance testing.

(c) Indicators of internal piping corrosion include reduced flow rates, debris in drain lines, and low supply pressure. To determine if internal corrosion is occurring, PG&E monitors pressure during periodic system flow tests. Increased inspections would be implemented for the affected piping and components if testing results yield a reduction of full flow pressure greater than 10 percent of previous test pressures or if flow blockage is experienced during the tests.

(d) RIC in the fire water system is applicable only to above ground piping portions of the system. As discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3, buried fire water piping is managed by annual flow tests conducted in accordance with NFPA-25, Section 7.3. If test results indicate deterioration, the results will be evaluated to determine if further actions are required. Since RIC has not been identified in the buried portions of the fire water system, annual flow testing is sufficient to manage potential aging.

(e) As discussed above, RIC in the fire water system is applicable only to above ground portions of the system. Buried fire water piping is managed by annual flow tests conducted in accordance with NFPA-25, Section 7.3. If test results indicate deterioration, the results will be evaluated to determine if further actions are required. Since RIC has not been identified in the buried portions of the fire water system, annual flow testing is sufficient to manage potential aging.

*RAI B2.1.15-2*

*Background:*

*Attachment 17 of the applicant's 2014 annual update (December 22, 2014) states that participation in the Electric Power Research Institute (EPRI) (PWR) Supplemental Surveillance Program includes donation of up to seven Charpy V-Notch specimens (material Plate B5454-1) from the already tested Unit 2 Capsule V. The applicant indicated that, because the donated specimens will no longer be stored, the specimen donation is an exception to the Generic Aging Lessons Learned (GALL) Report (Rev. 1) aging management program (AMP) XI.M31 guidance that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage for future reconstitution use, in case the surveillance program is reestablished.*

*10 CFR 50.61(c)(2) requires that licensees shall consider plant-specific information that could affect the level of embrittlement to verify that $RT_{NDT}$ (adjusted reference temperature) for each vessel beltline material is a bounding value for the specific reactor vessel. 10 CFR 50.61(c)(2) also states that this information includes but is not limited to the reactor vessel operating temperature and any related surveillance program results.*

*Issue:*

*The staff noted that LRA Table 4.2-3 indicates that the B5454-1 plate material is a reactor vessel beltline material of Unit 2. It is unclear to the staff whether the applicant will consider test data on B5454-1 plate material, which will be obtained from the EPRI PWR Supplemental Surveillance Program, in its reactor vessel embrittlement evaluations such as evaluations to determine adjusted reference temperature and upper-shelf energy.*

*Request:*

*Clarify whether the applicant will consider test data regarding the B5454-1 plate material, which will be obtained from the EPRI PWR Supplemental Surveillance Program, in its reactor vessel embrittlement evaluations such as evaluations to determine adjusted reference temperature and upper-shelf energy. If not, provide justification for why the applicant will not consider the test data in its reactor vessel embrittlement evaluations.*

PG&E Response to RAI B2.1.15-2

As described in LRA, Section 4.2, reactor vessel embrittlement analyses have been completed for 60 years of operation using credible data and have yielded results within acceptable ranges. Thus, no additional test data is required to demonstrate compliance specifically for 60 years of operation. However, in accordance with the DCPP Supplemental SER 13, dated April 1981, PG&E will consider new test data information (which encompasses the test data regarding B5454-1 material that will be obtained from the EPRI PWR Supplemental Surveillance Program) in future reactor vessel embrittlement evaluations conducted under the DCPP Reactor Vessel Surveillance Program (B2.1.15).

*RAI B2.1.18-3*

*Background:*

*As amended by letter dated December 22, 2014, LRA Section B2.1.18, "Buried Piping and Tanks Inspection Program," states that for steel piping, where cathodic protection is not available or does not meet the acceptance criteria in LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'," Table 4a, "Inspection of Buried Pipe," footnote 2.C., the number of inspections will be based upon soil sampling results.*

*LR-ISG-2011-03, Table 4a footnote 2.C, recommends that inspections should be escalated to preventive action Category F if leaks have occurred in buried piping due to external corrosion, or significant coating degradation or metal loss has been detected in more than 10 percent of inspections conducted.*

*Issue:*

*Although soil sampling is one of the inputs to determine whether increased inspections should be conducted (i.e., preventive action Category F), LR-ISG-2011-03 AMP XI.M41, Table 4a, footnote E.ii, recommends that plant-specific operating experience should also be considered.*

*Request:*

*State and justify the basis for why plant-specific operating experience should not be considered in addition to soil sampling results when considering the need to implement preventive action Category F inspections.*

PG&E Response to RAI B2.1.18-3

In addition to addressing RAI B2.1.18-3, PG&E is updating the licensing basis for the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) to address the recommendations in draft LR-ISG-2015-01, as shown in Enclosure 2.

PG&E amends the response in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3 to address this RAI and draft LR-ISG-2015-01 as follows:

> If cathodic protection for the cathodically-protected steel piping does not meet acceptance criteria (draft LR-ISG-2015-01, Appendix B, Table 4, Note C), PG&E will perform the scope of inspections as defined in draft LR-ISG-2015-01, Appendix B, Table 4, Preventive Action Categories D, E, or F, with the inspection quantities increased by 50 percent of the values listed in the table. As defined in draft LR-ISG-2015-01, Appendix B, Table 4, Notes D, E, and F, PG&E will perform the Preventive Action Category (D, E, or F) as required.

PG&E amends LRA, Section A1.18 and Table A4-1, Item 52 to reflect this updated licensing basis, as shown in Enclosure 3.

*RAI B2.1.18-4*

*Background:*

*As amended by letter dated December 22, 2014, the Buried Piping and Tanks Inspection Program does not state what buried component inspection findings would be considered as adverse indications. In addition, with the exception of cathodic protection acceptance criterion, the program does not state that it will be consistent with the "acceptance criteria" program element of LR-ISG-2011-03 AMP XI.M41.*

*LR-ISG-2011-03 AMP XI.M41 recommends that examples of adverse indications resulting from inspections include leaks, material thickness less than minimum, coarse backfill within 6 inches of a coated pipe or tank with accompanying coating degradation, and general or local degradation of coatings so as to expose the base material.*

*LR-ISG-2011-03 AMP XI.M41 recommends acceptance criteria such as: (a) if components show evidence of corrosion, the remaining wall thickness in the affected area should be determined and (b) for hydrostatic tests, the test acceptance criteria is*

*no visible indications of leakage and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or quantified leakage across test boundary valves.*

*Issue:*

*It is unclear to the staff whether the "detection of aging effects" and "acceptance criteria" program elements will be consistent with the GALL Report AMP XI.M41 because adverse indications were not defined and acceptance criteria were not stated for activities such as wall thickness verification and hydrostatic tests in lieu of visual inspections.*

*Request:*

*State what indications would be considered as adverse indications and the acceptance criteria for the program.*

PG&E Response to RAI B2.1.18-4

In addition to addressing RAI B2.1.18-4, PG&E is updating the licensing basis for the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) to address the recommendations in draft LR-ISG-2015-01, as shown in Enclosure 2.

As discussed in draft LR-ISG-2015-01, the term "adverse indications" as used in LR-ISG-2011-03 was replaced with "coatings, backfill or the condition of exposed piping that does not meet acceptance criteria." PG&E's Buried Piping and Tanks Inspection Program will be consistent with draft LR-ISG-2015-01, Appendix B, Section 7, "Corrective Actions," for inspection findings that do not meet acceptance criteria (previously labeled as adverse indications).

PG&E's Buried Piping and Tanks Inspection Program acceptance criteria will be consistent with draft LR-ISG-2015-01, Appendix B, Section 6 except as described below.

Draft LR-ISG-2015-01, Appendix B, Section 6.a, states that "coating degradation is evaluated as insignificant by an individual processing a NACE Coating Inspector Program Level 2 or 3 inspector qualification, or an individual who has attended the Electric Power Research Institute (EPRI) Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course." In lieu of committing specifically to a NACE or EPRI qualification, PG&E qualifies the coating inspection personnel based on ASTM D4537, "Standard Guide for Establishing Procedures to Qualify and Certify Personnel Performing Coating and Lining Work Inspection in Nuclear Facilities," plant experience, and nuclear coating knowledge, which is endorsed by the NRC RG 1.54. This is also

consistent with NRC recommendations in LR-ISG-2013-01 for coatings on internal surfaces of in scope piping, piping components, heat exchangers, and tanks.

PG&E amends LRA, Section A1.18 and Table A4-1, Item 52, as shown in Enclosure 3.

*RAI B2.1.18-5*

*Background:*

*Amendment 48, dated December 22, 2014, states that there are no aging effects requiring management (AERM) for steel and stainless steel piping, piping components, and tanks encased in concrete. The amendment states that this is supported by SRP-LR Table 3.3-1 line item 3.3.1-112, which states that for steel piping embedded in concrete there are no AERM and no recommended AMP as long as the concrete meets certain attributes (i.e., low water-to-cement ratio, low permeability, and adequate air entrainment) and there is no plant-specific operating experience related to degradation of the concrete. For the stainless steel components embedded in concrete, the amendment cites line item 3.3.1-120, which states that there are no AERM and no recommended AMP. The amendment also states that a majority of the piping and piping components are within buildings where the potential for water intrusion into the concrete is very low. The amendment further states that there has been no plant-specific operating experience revealing aging effects for metallic components embedded in concrete. Amendment 48 further states that letter dated November 24, 2010, further justifies the lack of aging effects for piping embedded in concrete. This letter states, "[t]he ASW system piping that is not cathodically protected is encased in concrete. The concrete provides a noncorrosive environment for the steel piping such that CP is not necessary and there are no aging effects."*

*GALL Report Items E-42, EP-31, S-01, and SP-37 state that loss of material is managed for steel and stainless steel piping and piping components exposed to soil or concrete by AMP XI.M41.*

*Issue:*

*The staff has concluded that there is reasonable assurance that there are no AERM for components that are: (a) embedded in concrete that are within buildings and (b) not potentially externally exposed to water. However, for components where the concrete is exposed to soil, due to the potential for exposure to water, loss of material should be managed by LR-ISG-2011-03, AMP XI.M41.*

*Request:*

*For components that are embedded in concrete that are exposed to soil, state and justify the basis for why water will not penetrate the concrete and potentially cause loss of material.*

PG&E Response to RAI B2.1.18-5

As stated in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3, item 11, the buried piping encased in concrete for which PG&E states no aging effect requiring management is the ASW discharge piping. There is reasonable assurance that the exterior surface of the buried ASW piping encased in concrete will continue to perform its intended function during the period of extended operation consistent with the current licensing basis because the piping is encased in structural concrete. The ASW piping encased in concrete meets American Concrete Institute (ACI) 318. Cracking of this concrete is controlled through proper arrangement and distribution of reinforcing steel and is constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI. In addition, the ASW discharge piping is located approximately 57 feet above the anticipated high ground water elevation.

PG&E amends LRA, Section A1.18 and Table A4-1, Item 52, as shown in Enclosure 3.

*RAI B2.1.22-5*

*Background:*

*GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as revised by Interim Staff Guidance for License Renewal (LR-ISG)-2012-02, states that verification of the effectiveness of the AMP is performed to ensure that degradation is not occurring in inaccessible locations, such as exterior portions of the tanks in contact with concrete. Table 4a, "Tank Inspection Recommendations," in LR-ISG-2012-02 recommends that volumetric inspections be conducted on the external surfaces of tank bottoms and shells exposed to concrete to manage the aging effect of loss of material.*

*By letter dated December 22, 2014, multiple sections of the LRA were amended in response to LR-ISG-2012-02. Enclosure 1, Attachment 7D, of the letter states that the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank are outdoor and sit on concrete foundations. LRA Tables 3.2.2-1 and 3.2.2-5 were revised to include aging management review (AMR) items for these tanks that reference the Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components Program. The AMR items cite plant specific notes indicating that the tank bottoms are to be volumetrically inspected for loss of material. Attachment 7D also states that these tanks are encased in concrete and that there are no aging effects to be managed for the external surfaces.*

*Issue:*

*The tank bottoms and side walls are both exposed to concrete; however, the aging effect of loss of material is only being managed for the tank bottoms. It is unclear to the staff what actions will be taken to ensure that degradation is not occurring at inaccessible locations of tank shells, specifically the external surfaces of the tank shells exposed to concrete.*

*Request:*

*State the basis for ensuring that degradation is not occurring at the external surfaces of tank shells for the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank given that volumetric inspections are not being performed in accordance with Table 4a of AMP XI.M29 in LR-ISG-2012-02.*

PG&E Response to RAI B2.1.22-5

PG&E amends its response in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7D as follows:

Consistent with GALL Report AMP XI.M29, "Aboveground Metallic Tanks," Table 4a, "Tank Inspection Recommendations," in LR-ISG-2012-02, PG&E will conduct volumetric inspections on the internal surfaces of the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank bottoms and shells to manage the tank bottoms and side wall external surfaces of the tanks exposed to concrete.

PG&E amends LRA, Table A4-1, item 9, Section A1.22, and plant-specific notes associated with the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank in LRA Tables 3.2.2-1 and 3.3.2-5, as shown in Enclosure 3.

*RAI B2.1.22-6*

*Background:*

*Annual update letter, dated December 22, 2014, provides changes to the LRA that address issues from LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." Attachment 7A of the letter states that, as discussed in LR-ISG-2012-02, Section A, recurring internal corrosion (RIC) was identified in copper alloy components exposed to potable water in the makeup water system, and the internal surfaces of these components are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The letter also states:*

> *following a failure of the copper components exposed to potable water due to RIC, this program will be used to either: (a) replace the component with a material that is more corrosion-resistant; (b) take corrective actions to prevent recurrence of the RIC; (c) perform augmented inspections to detect aging before a loss of function occurs, or; (d) credit mitigating actions in accordance with NEI 95-10, Appendix F.*

*As modified by LR-ISG-2012-02, SRP-LR includes further evaluation Section 3.3.2.2.8, "Loss of Material due to Recurring Internal Corrosion." The further evaluation section recommends that if recurring aging effects are identified the applicant addresses the following five aspects:*

> *(a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

*With regard to potential augmented requirements, SRP-LR Section 3.3.2.2.8 states that these include:*

> *alternate examination methods, (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.*

*In addition, as modified by LR-ISG-2012-02, GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that if RIC has occurred, a plant specific program will be necessary unless this program includes augmented requirements to ensure that any recurring aging effects are adequately managed. The modified AMP XI.M38 also states that this program may be used if the failed material is replaced by one that is more corrosion-resistant. The staff's intent was for all of the susceptible material to be replaced with more corrosion-resistant material, not just the components that fail.*

*Issue:*

*Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. The annual update letter states that one of the four approaches that could be taken following a failure is to "perform augmented inspections to detect aging before a loss of function occurs." However, GALL AMP XI.M38 includes the detection of aging effects and the need for corrective actions before loss of intended function (i.e., failure). Since RIC has been identified in copper alloy components in the makeup water system, it is unclear to the staff which of the four approaches was used to resolve this issue in the past. Unless one of the other four approaches was taken for these past occurrences (which should have provided a long term solution and precluded the need for managing this issue), the staff is unclear what augmented inspections were performed and if these condition monitoring activities are continuing and will continue during the period of extended operation (PEO).*

*Request:*

*For the prior occurrences which led to the identification of RIC in copper alloy components of the makeup water system, provide information relating to how these issues were previously addressed. If past activities did not provide a long term solution and preclude the need for managing this issue, provide details related to augmented inspections that will be included in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and discuss how RIC will be identified before loss of intended function occurs throughout the PEO. Include information relating to the five specific further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8.*

PG&E Response to RAI B2.1.22-6

For copper alloy piping portions of the domestic water system that are in the scope of license renewal, PG&E entered the in-scope a(2) piping into the CAP for an engineering evaluation. PG&E is in the process of implementing corrective actions prior to the period of extended operation that include replacing the piping with a material that is more corrosion-resistant, or installing pipe shielding in accordance with NEI 95-10 Appendix F which will be aging managed in accordance with the External Surfaces Monitoring Program. PG&E believes these corrective actions will provide a long-term solution and preclude the need for managing the recurring internal corrosion through augmented inspections.

As shown in Enclosure 3, PG&E amends LRA, Table A4-1 to add a new commitment (Item 75) and Table 3.3.2-5 to add a new plant-specific note that describes the corrective actions.

**Draft LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations'"**

Draft LR-ISG-2015-01 contains recommended technical and editorial changes to Aging Management Program (AMP) XI.M41, "Buried and Underground Piping and Tanks."

PG&E's licensing basis for the DCPP Buried Piping and Tanks Inspection program (B2.1.18) is documented in the following letters:

(1) PG&E Letter DCL-09-079, "License Renewal Application," dated November 23, 2009
(2) PG&E Letter DCL-10-097, "Response to NRC Letter date July 19, 2010, Request for Additional Information (Set 9) to the Diablo Canyon License Renewal Application," dated August 2, 2010
(3) PG&E Letter DCL-10-113, "Response to NRC Letter dated August 3, 2010, Request for Additional Information (Set 16) for the Diablo Canyon License Renewal Application," dated August 30, 2010
(4) PG&E Letter DCL-10-148, "Response to NRC Letter dated November 03, 2010, Request for Additional Information (Set 29) for the Diablo Canyon License Renewal Application," dated November 24, 2010
(5) PG&E Letter DCL-11-002, "Response to Telephone Conference Call Held on December 9, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated January 21, 2011
(6) PG&E Letter DCL-11-022, "Pacific Gas and Electric Company Supplements a Response to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated March 14, 2011
(7) PG&E Letter DCL-14-103, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 48 and LRA Appendix E, Applicant's Environmental Report – Operating License Renewal Stage, Amendment 1," dated December 22, 2014

PG&E prepared its license renewal application (LRA) based on the guidance in NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Revision 1, September 2005. The NRC staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1801, Revision 1. The NRC staff issued Draft NUREG-1801, Revision 2 in September 2010. The NRC staff considered the operating experience summarized in the Draft NUREG-1801, Revision 2 and requested PG&E to address selected items. This review is summarized in the License Renewal Safety Evaluation Report (SER), dated June 2, 2011. Subsequent to issuance of the SER, PG&E revised its LRA licensing basis in accordance with 10 CFR 54.21(b) and also addressed Interim Staff Guidance LR-ISG-2011-03, which provided revisions to the

GALL, Revision 2, XI.M41, Buried and Underground Piping and Tanks AMP by including specific additional guidance, which was not previously reviewed in the SER.

Draft LR-ISG-2015-01 was issued in June 2015 and provided further specific guidance in the form of changes to technical and editorial guidance. In order to address the recommendations in Draft LR-ISG-2015-01, PG&E updates its licensing basis for the Diablo Canyon Power Plant (DCPP) Buried Piping and Tanks Inspection Program (B2.1.18) to be in compliance with the specific changes provided to GALL, Revision 2 in Draft LR-ISG-2015-01 as discussed in this enclosure.

LRA Sections A1 and A1.18 and Table A4-1, Item 52 are revised to address Draft LR-ISG-2015-01 as shown in Enclosure 3.

In addition to evaluating draft LR-ISG-2015-01, PG&E is updating the licensing basis regarding installation of cathodic protection (CP) and required inspections for the underground diesel fuel oil piping.

Cathodic Protection:
PG&E is currently in the design phase of upgrading its CP system on Unit 1 and 2 buried, in-soil auxiliary saltwater system piping and is further evaluating the feasibility of protecting all subject piping. For some small portions, it may be impractical to install CP. PG&E will update the CP licensing basis by December 31, 2015 (see Enclosure 4).

Underground Diesel Fuel Oil Piping Inspections:
PG&E Letters DCL-10-148 and DCL-14-103 discuss the inspection frequency, amount of piping to be inspected, and type of inspection of the underground diesel fuel oil piping which will be performed as part of the DCPP Buried Piping and Tanks Inspection Program. As indicated above, PG&E revises the previous licensing basis in these letters to perform the inspection of this piping in accordance with the inspection frequency, amount of piping to be inspected, and type of inspection as discussed in Draft LR-ISG-2015-01.

**LRA Amendment 50**

| LRA Section | Reason for Change |
|---|---|
| Section 3.1.2.2.3.1 | RAI 3.1.2.2.3.1-1 |
| Table 3.2.2-1 | RAI B2.1.22-5 |
| Table 3.3.2-5 | RAI B2.1.22-5<br>RAI B2.1.22-6 |
| Table 3.4.2-1 | RAI 3.4.2.3.1-1<br>RAI 3.4.2.3.1-2<br>RAI 3.4.2.3.1-3 |
| Section 4.2.3 | RAI 4.2.3-1 |
| Section A1 | LR-ISG-2015-01 |
| Section A1.13 | RAI 3.0.3.2.6-4 |
| Section A1.18 | RAI B2.1.18-3<br>RAI B2.1.18-4<br>RAI B2.1.18-5<br>LR-ISG-2015-01 |
| Section A1.22 | RAI B2.1.22-5 |
| Section A1.42 | RAI 3.4.2.3.1-1<br>RAI 3.4.2.3.1-2<br>RAI 3.4.2.3.1-3<br>RAI B2.1.9-2 |
| Table A4-1, Items 9, 52, 74, 75 | RAI 3.4.2.3.1-1<br>RAI 3.4.2.3.1-2<br>RAI 3.4.2.3.1-3<br>RAI B2.1.18-3<br>RAI B2.1.18-4<br>RAI B2.1.18-5<br>RAI B2.1.22-5<br>RAI B2.1.22-6<br>LR-ISG-2015-01 |
| Section B2.1.42 | RAI 3.4.2.3.1-1<br>RAI 3.4.2.3.1-2<br>RAI 3.4.2.3.1-3<br>RAI B2.1.9-2 |

3.1.2.2.3.1 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement - TLAA

Evaluation of loss of fracture toughness is a TLAA as defined in 10 CFR 54.3. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1).

Paragraph deleted in PG&E Letter DCL-13-119

~~For the Unit 1 reactor vessel, PG&E will implement the revised PTS rule, 10 CFR 50.61a, at least three years prior to exceeding the PTS screening criterion of 10 CFR 50.61. In the event that the provisions of 10 CFR 50.61 a cannot be met, PG&E will implement alternate options, such as flux reduction, as provided in 10 CFR 50.61.~~

For the Unit *1 and Unit* 2 reactor vessel*s*, recent coupon examinations demonstrated that beltline materials will remain limiting, and that adequate adjusted reference temperature, upper shelf energy, and pressurized thermal shock screening temperature margin will remain at the end of the period of extended operation; and therefore that subsequent revisions to pressure-temperature limits will provide adequate operating margin, without the use of special methods.

An evaluation of the axial fluence distribution for the reactor vessel nozzles found that the projected embrittlement parameters for these materials will not be limiting.
Loss of fracture toughness for the reactor vessel shell and nozzles is managed with the Reactor Vessel Surveillance program (B2.1.15). Section 4.2 describes the disposition of these neutron embrittlement TLAAs.

*Table 3.2.2-1 Engineered Safety Features – Summary of Aging Management Evaluation – Safety Injection System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Tank | PB | Stainless Steel | Concrete | Loss of material | Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components (B2.1.22) | None | None | G, 6 |

6. The Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components (B2.1.22) is used to inspect tanks in the scope of XI.M29 from the internal surface. Reference LR-ISG-2012-02, Appendix C, Line V.D1.E-402, ~~and~~ PG&E Letter DCL-14-103, Enclosure 1, Attachment 7D, *and PG&E Letter DCL-15-121 in response to RAI B2.1.22-5*.

*Table 3.3.2-5 Auxiliary Systems – Summary of Aging Management Evaluation – Makeup Water System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Tanks | PB | Carbon Steel | Concrete | Loss of material | Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components (B2.1.22) | None | None | G, 9 |
| Piping | LBS | Copper Alloy | Potable Water (Int) | Loss of material; recurring internal corrosion | Inspection of Internal Surfaces in Miscellaneous piping and Ducting Components (B2.1.22) | None | None | G, 7, *10* |

*9.* The Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components (B2.1.22) is used to inspect tanks in the scope of XI.M29 from the internal surface. Reference LR-ISG-2012-02, Appendix C, Line VII.C3.A-401, ~~and~~ PG&E Letter DCL-14-103, Enclosure 1, Attachment 7D, *and PG&E Letter DCL-15-121 in response to RAI B2.1.22-5*.

~~9.~~*10. To address recurring internal corrosion, corrective actions will be implemented that include replacing the piping with a material that is more corrosion-resistant, or installing pipe shielding in accordance with NEI 95-10 Appendix F which will be aging managed in accordance with the External Surfaces Monitoring program (B2.1.20). Reference PG&E Letter DCL-15-121, RAI B2.1.22-6.*

*Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Demineralizer | LBS | Carbon Steel (with coating or lining) | *Demineralized* ~~Secondary~~ Water (Int) | Loss of ~~coating integrity~~*material* | *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Heat Exchangers and Ducting Components* ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks~~ (B2.1.4~~2~~2) | *VIII.D1-4*~~None~~ | *3.4.1.16*~~None~~ | *E, 3*~~H, 9~~ |
| ~~Demineralizer~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Secondary Water (Int)~~ | ~~Loss of material~~ | ~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~ | ~~VIII.D1-8~~ | ~~3.4.1.04~~ | ~~A~~ |
| Piping | LBS | Carbon Steel (with coating or lining) | *Demineralized* ~~Secondary~~ Water (Int) | *Loss of material*~~Loss of coating integrity~~ | *Inspection of* Internal *Surfaces in Miscellaneous Piping and Ducting Components, Heat Exchangers and Ducting Components* ~~Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks~~ (B2.1.4~~2~~22) | *VIII.D1-4*~~None~~ | *3.4.1.16*~~None~~ | *E, 3*~~H, 9~~ |
| ~~Piping~~ | ~~LBS~~ | ~~Carbon Steel (with coating or lining)~~ | ~~Sodium Hydroxide (Int)~~ | ~~Loss of coating integrity~~ | ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | ~~None~~ | ~~None~~ | ~~H, 9~~ |

*Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| ~~Piping~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Sodium Hydroxide (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 5~~ |
| ~~Piping~~ | ~~LBS~~ | ~~Carbon Steel (with coating or lining)~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of coating integrity~~ | ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | ~~None~~ | ~~None~~ | ~~H, 9~~ |
| ~~Piping~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 3~~ |
| ~~Tank~~ | ~~LBS, SIA~~ | ~~Carbon Steel~~ | ~~Secondary Water (Int)~~ | ~~Loss of material~~ | ~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~ | ~~VIII.D1-8~~ | ~~3.4.1.04~~ | ~~C~~ |
| Tank | LBS, *SIA* | Carbon Steel (with coating or lining) | *Demineralized Water*~~Sodium Hydroxide~~ (Int) | *Loss of material*~~Loss of coating integrity~~ | *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Heat Exchangers and Ducting Components (B2.1.22)*~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | *VIII.D1-4*~~None~~ | *3.4.1.16*~~None~~ | *E, 3*~~H, 9~~ |

*Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| ~~Tank~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Sodium Hydroxide (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 5~~ |
| ~~Tank~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 3~~ |
| ~~Tank~~ | ~~LBS~~ | ~~Carbon Steel (with coating or lining)~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of coating integrity~~ | ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | ~~None~~ | ~~None~~ | ~~H, 9~~ |
| Valve | LBS, *SIA* | Carbon Steel (with coating or lining) | *Demineralized* ~~Secondary~~ Water (Int) | *Loss of material*~~Loss of coating integrity~~ | *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Heat Exchangers and Ducting Components (B2.1.22)*~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | *VIII.D1-4*~~None~~ | *3.4.1.16*~~None~~ | *E, 3*~~H, 9~~ |

*Table 3.4.2-1 Steam and Power Conversion System – Summary of Aging Management Evaluation – Turbine Steam Supply System*

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Program | NUREG-1801 Vol. 2 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| ~~Valve~~ | ~~LBS, SIA~~ | ~~Carbon Steel~~ | ~~Sodium Hydroxide (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 5~~ |
| ~~Valve~~ | ~~LBS~~ | ~~Carbon Steel (with coating or lining)~~ | ~~Sodium Hydroxide (Int)~~ | ~~Loss of coating integrity~~ | ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | ~~None~~ | ~~None~~ | ~~H, 9~~ |
| ~~Valve~~ | ~~LBS~~ | ~~Carbon Steel~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of material~~ | ~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~ | ~~None~~ | ~~None~~ | ~~G, 3~~ |
| ~~Valve~~ | ~~LBS~~ | ~~Carbon Steel (with coating or lining)~~ | ~~Sulfuric Acid (Int)~~ | ~~Loss of coating integrity~~ | ~~Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42)~~ | ~~None~~ | ~~None~~ | ~~H, 9~~ |

Plant Specific Notes:

3 *These components in the Steam Generator Blowdown Treatment Demineralizer system may be temporarily exposed to sulfuric acid, sodium hydroxide, or secondary water at 110°F for short durations of time in the event of a steam generator tube leak, but the normal long-term internal environment will be demineralized water. In accordance with LR-ISG-2013-01, as documented in PG&E Letter DCL-15-121 in response to RAIs 3.4.2.3.1-1, 3.4.2.3.1-2, 3.4.2.3.1-3 these components will be managed using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program (B2.1.22).* ~~These carbon steel components are located on the sulfuric acid skid containing sodium hydroxide and sulfuric acid used for regeneration of the steam generator blowdown demineralizer resin.~~

~~9 The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.42) program is used to monitor demineralizers, piping, tanks and valves fabricated from carbon steel (with internal coating or lining) with an internal environment of secondary~~

~~water, sodium hydroxide, or sulfuric acid for loss of coating integrity. Reference PG&E Letter DCL-15-027, Enclosure 1 in response to LR-ISG-2013-01, Appendix B, Table VIII.~~

### 4.2.3 Charpy Upper-Shelf Energy

*Unit 1*

In accordance with Regulatory Guide 1.99, the $C_V$ USE data from Unit 1 surveillance Capsule V were determined not to be credible *for determination of $\Delta RT_{NDT}$, but*~~and~~ were *credible for determining* ~~, therefore, not included in~~ the EOLE $C_V$ USE projections.

# A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. Sections A1 and A2 describe the programs and their implementation activities.

Three elements common to all aging management programs discussed in Sections A1 and A2 are corrective actions, confirmation process, and administrative controls. The DCPP Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components that are subject to aging management activities.

Operating experience from plant-specific and industry sources is systematically reviewed on an ongoing basis in accordance with the Quality Assurance Program, which meets the requirements of 10 CFR 50, Appendix B, and the operating experience program, which meets the requirements of NUREG-0737, Item I.C.5. The operating experience program interfaces with and relies on active participation in the Institute of Nuclear Power Operations' (INPO) operating experience program as endorsed in NRC Generic Letter 82-04.

The programs and procedures relied upon to meet the requirements of 10 CFR 50, Appendix B, and NUREG-0737, Item I.C.5 will be enhanced to ensure that plant-specific and incoming external operating experience related to age-related degradation and aging management will be systematically evaluated. The ongoing review of operating experience information will provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the structure- and component-intended functions will be maintained during the period of extended operation. When an evaluation determines that the effects of aging may not be adequately managed, existing AMPs will be enhanced or new AMPs will be developed. The following enhancements will be implemented no later than the date the renewed operating license is issued and will be maintained and throughout the term of the renewed license:

(1) A specific identification code will be defined and used in the Corrective Action Program (CAP) to consistently identify operating experience concerning age-related degradation applicable to DCPP. Entries associated with this code will be periodically reviewed by plant personnel and adverse trends will be entered into the CAP for evaluation.

(2) Plant-specific and incoming industry operating experience will be screened to determine whether they may involve age-related degradation or aging

management impacts. Sources of industry operating experience will include License Renewal Interim Staff Guidance (LR-ISG) documents; all revisions to NUREG-1801; and other NRC and industry guidance documents and standards applicable to aging management, such as Information Notices, Regulatory Issue Summaries, etc.

(3) Items coded as concerning age-related degradation applicable to DCPP will require further evaluation.

(4) Plant-specific operating experience associated with age-related degradation and aging management will be reported to the industry in accordance with guidelines established in the operating experience program. This reporting will be accomplished through participation in the INPO operating experience program.

(5) An evaluation of plant-specific and industry operating experience will be performed during the development and implementation of new AMPs and documented in the new AMP.

(6) Further evaluation of plant-specific and industry operating experience that potentially involves aging will be entered in the CAP and evaluated. The evaluation will be documented and will consider as appropriate: (a) systems, structures and components (SSCs) that are similar or identical to those involved with the identified operating experience issue, to gain relevant lessons learned; (b) material of construction, operating environment and aging effects associated with the identified aging issue so that lessons learned can be applied to susceptible SSCs within the scope of license renewal; (c) aging mechanisms associated with the operating experience to confirm that DCPP has appropriate AMPs in place to manage aging that could be caused by these mechanisms; (d) AMPs associated with this operating experience so that if the AMPs have been demonstrated to be ineffective, similar AMPs in place at DCPP can be evaluated to determine if AMP changes are appropriate, or a new AMP is needed. Included in this review is consideration of activities, criteria, and evaluations integral to the elements of the plant AMPs.

(7) The results of implementing each AMP, both acceptable and unacceptable, will be evaluated to determine whether the effects of aging are adequately managed. A determination will be made as to whether the frequency of future inspections should be adjusted, whether new inspections should be established, and whether the inspection scope should be adjusted or expanded. If there is an indication that the effects of aging may not be adequately managed, the CAP will be used to either enhance the AMP or develop and implement new AMPs.

(8) Initial and periodic training on age-related degradation and aging management will be provided to those personnel responsible for implementing the AMPs and

personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience.

The DCPP program for the ongoing review of operating experience implements the recommendations in LR-ISG-2011-05, as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 5.

*PG&E prepared its license renewal application (LRA) based on the guidance in NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Revision 1, dated September 2005. The NRC staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1801, Revision 1. The NRC staff issued Draft NUREG-1801, Revision 2 in September 2010. The NRC staff considered the operating experience summarized in the Draft NUREG-1801, Revision 2, and requested PG&E to address selected items. This reviewed is summarized in the Diablo Canyon License Renewal Safety Evaluation Report (SER), dated June 2, 2011. Subsequent to issuance of the June 2, 2011 SER, PG&E revised its LRA licensing basis to address several LR-ISGs. The LR-ISGs provided revisions to the GALL, Revision 2, AMPs by including specific additional guidance, which was not previously reviewed in the SER. The DCPP aging management programs are in compliance with the guidance provided in the LR-ISGs, as discussed in regulatory correspondence referenced in the applicable aging management program descriptions throughout Section A1.*

## A1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material due to corrosion, including MIC, fouling, flow blockage because of fouling, and loss of integrity for water-based fire protection systems and internal coatings/linings for the fire water storage tank within the scope of license renewal. Internal and external inspections and tests of fire protection equipment are performed consistent, with exceptions identified in PG&E Letters DCL-14-103, Enclosure 1, Attachment 7C, *and DCL-15-121,* with NFPA-25 (2011 edition). Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA-25 (2011 edition). Portions of the deluge systems that are normally dry but periodically subjected to flow and cannot be drained or allow water to collect will undergo augmented testing beyond that in NFPA-25 consisting of volumetric wall thickness examinations. The fire water system is managed by performing routine preventive maintenance, inspections and testing; operator rounds, performance monitoring, and reliance on the corrective action program; and system improvements to address aging and obsolescence issues. *The fire water system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions are initiated.*

The Fire Water System program will conduct a flow test with air, water, or other medium through each open spray nozzle to verify that deluge systems nozzles are unobstructed. Water flow tests will verify that the deluge system provide full coverage of the equipment it protects. Visual inspections will be performed on firewater piping. Non-intrusive follow-up volumetric examinations will be performed if internal visual inspections detect surface irregularities to determine if wall thickness is within acceptable limits. Visual inspections will evaluate for the presence of sufficient foreign material to obstruct fire water pipe or sprinklers.

Inspections of the firewater tank will be performed to detect loss of material.

As discussed in PG&E Letter DCL-15-027, Enclosure 1, in response to LR-ISG-2013-01, the program consists of periodic visual inspections of the internal liner of the fire water storage tank exposed to raw water where loss of lining integrity could impact the components' and downstream components' current licensing basis intended function(s). For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair, replacement, or removal of the lining. The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the NRC associated with a particular standard.

The Fire Water program implements the recommendations in LR-ISG-2012-02, as discussed in PG&E Letters DCL-14-103, Enclosure 1, Attachments 7C *and DCL-15-121,* and the recommendations in LR-ISG-2013-01, as discussed in PG&E Letter DCL-15-027.

## A1.18 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection program manages cracking, loss of material, and change in surface conditions of buried and underground piping, piping components and tanks in the auxiliary saltwater system, diesel generator fuel transfer system, fire protection system, and the makeup water system. The program manages aging through preventive, mitigative, (i.e., coatings, backfill quality, and cathodic protection) and inspection activities. Visual inspections monitor the condition of protective coatings and wrappings found on steel and copper alloy components and directly assess the surface condition of cast iron, polyvinyl chloride, and asbestos cement components with no protective coatings or wraps. Evidence of damaged wrapping or coating defects is an indicator of possible age-related degradation to the external surface of the components. The presence of discolorations, discontinuities in surface texture, cracking, crazing, changes in material properties or loss of material of unwrapped cast iron, polyvinyl chloride, and asbestos cement components is an indicator of possible aging of the external surface of the components. The program includes opportunistic inspection of buried piping and tanks as they are excavated or on a planned basis if opportunistic inspections have not occurred.

Soil samples will be conducted in the vicinity of in-scope buried, non-cathodically protected steel piping and piping components. Soil samples will be conducted in the vicinity of in-scope buried auxiliary saltwater system steel piping in which the cathodic protection system does not meet the availability or effectiveness requirements. Soil samples will be conducted during the ten-year period prior to the period of extended operation and in each subsequent ten-year period during the period of extended operation.

Alternative to visual inspection of the external surface of steel piping, hydrostatic testing or an inspection of the internal surface of the piping that is capable of precisely determining pipe wall thickness may be used.

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended operation. Inspections will be conducted during each 10-year period beginning 10 years prior to entering the period of extended operation. Examinations of buried piping will consist of visual inspections. Significant indications of degradation observed during visual inspections of buried piping will require a supplemental surface and/or volumetric non-destructive testing.

The Buried Piping and Tanks Inspection program implements the ~~recommendations~~ *specific additional guidance provided* in LR-ISG-2011-03 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3 *and the specific changes provided in draft LR-ISG-2015-01 as discussed in PG&E Letter DCL-15-121, Enclosures 1 and 2*.

## A1.22 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, loss of material, change in material properties, hardening, shrinkage, loss of sealing, crazing, dimensional change, and loss of strength of the internal surfaces of piping, piping components, and piping elements, ducting, heat exchanger components, polymeric and elastomeric components, tanks, and other components that are not within the scope of other aging management programs (i.e. exposed to environments of plant indoor air; atmosphere/weather; borated water leakage; diesel exhaust; and any water environment other than open-cycle cooling water, treated borated water, and fire water). The program addresses the management of aging internal surfaces of miscellaneous piping and ducting components that are inaccessible during both normal operations and refueling. The program allows internal inspections to be credited if the internal and external material and environment conditions are similar. If inspections of the interior surfaces of accessible components with material, environment, and aging effects similar to those of the interior surfaces of buried or underground components are not conducted, internal visual or external volumetric inspections capable of detecting loss of material on the internal surfaces will be conducted.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses the work control process to conduct and document inspections. The program performs visual inspections to detect aging effects that could result in a loss of component intended function. Visual inspections of internal surfaces of plant components are performed opportunistically during the conduct of periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance.

Additionally, visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of both internal and external surfaces of elastomers or by sufficient pressurization of the elastomer material to expand the surface in such a way that cracks or crazing is evident. The program also includes volumetric evaluation to detect stress corrosion cracking of the internal surfaces of stainless steel components exposed to diesel exhaust.

At a minimum, in each ten-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect), or a maximum of 25 components per population is inspected. Where practical, inspections focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. Inspections (other than opportunistic inspections) will be based on assessments of the potential degradation which could lead to loss of intended function, and on current industry and plant-specific operating experience. Opportunistic inspections will be based on assessments of the potential degradation

which could lead to loss of intended function, and on current industry and plant-specific operating experience.

In accordance with LR-ISG-2012-02, Appendix E, Table 4a, volumetric examination of the refueling water storage tanks, condensate storage tanks, and transfer tanks bottoms *and shells* from the inside will be performed for each ten-year period starting 10 years before entering the period of extended operation to confirm the absence of loss of material due to corrosion.

This program is not intended for use on piping and ducts where repetitive failures have occurred from loss of material that resulted in loss of intended function. However, if the criteria for recurring internal corrosion, as described in LR-ISG-2012-02, Section A are met, the use of this program is allowed if it includes augmented requirements to ensure that any recurring aging effects are adequately managed.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented six months prior to the period of extended operation, except for the volumetric tank inspections, which will begin ten years prior to the PEO in accordance with LR-ISG-2012-02, Appendix E, Table 4a. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program implements the recommendations in LR-ISG-2012-02, as discussed in PG&E Letters DCL-14-103, Enclosure 1, Attachments 7A, 7B, 7D, 7F, 7G, and 7H*, and DCL-15-121*.

## A1.42 INTERNAL COATINGS/LININGS FOR IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

The program consists of periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components exposed to closed-cycle cooling water, raw water, ~~secondary water, sulfuric acid, sodium hydroxide,~~ *demineralized water,* treated borated water, lubricating oil, or fuel oil where loss of coating or lining integrity could impact the component's and downstream component's current licensing basis intended function(s). For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in Regulatory Guide 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

The internal fire water storage tank liner will be managed using the Fire Water System program (A1.13). *The in-scope lined components in the steam generator blowdown treatment demineralizer system will be managed using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program (A1.22).*

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is a new program that will be implemented no later than six months prior to the period of extended operation with inspections beginning no later than the last refueling outage before the period of extended operation. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program implements the recommendations in LR-ISG-2013-01, as discussed in PG&E Letter*s* DCL-15-027, Enclosure 1*, and DCL-15-121*.

*Table A4-1 License Renewal Commitments*

| Item # | Commitment | LRA Section | Implementation Schedule |
|---|---|---|---|
| 9 | Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program as described in LRA Section B2.1.22 and to be in conformance with LR-ISG-2012-02 as discussed in PG&E Letters DCL-14-103, Enclosure 1, Attachments 7A, 7B, 7D, 7F, 7G, and 7H, *and DCL-15-121,* respectively. | B2.1.22 | Six months prior to the period of extended operation |
| 52 | The Buried Piping and Tanks Inspection Program will be revised to conform to *the specific additional guidance provided in* LR-ISG-2011-03 *and the specific changes provided in draft LR-ISG-2015-01* as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3 *and in PG&E Letter DCL-15-121, Enclosures 1 and 2, respectively*.<br><br>Fire mains will be subject to a periodic flow test in accordance with NFPA 25 section 7.3 at a frequency of at least one test in each one year period. These flow tests will be performed in lieu of excavating buried portions of Fire Water pipe for visual inspections. | B2.1.18 | Within 10 years prior to the period of extended operation |
| 74 | Implement the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program in conformance with LR-ISG-2013-01 as discussed in PG&E Letter DCL-15-027, Enclosure 1*, and PG&E Letter DCL-15-121*. | B2.1.42 | No later than six months before the period of extended operation and inspections begin no later than the last refueling outage before the period of extended operation |
| *75* | *For copper alloy piping portions of the domestic water system that are in the scope of license renewal, PG&E will replace the piping with a material that is more corrosion-resistant, or install pipe shielding to ensure that no adverse a(2) spatial interactions could occur.* | *B2.1.22* | *Prior to the period of extended operation* |

## B2.1.42 INTERNAL COATINGS/LININGS ON IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

### Program Description

Proper maintenance of internal coatings/linings is essential to ensure that the intended functions of in-scope components are met.

Degradation of coatings/linings can lead to loss of material, of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction in heat transfer when coatings/linings become debris. This program manages loss of coating integrity for piping, tanks, and heat exchangers fabricated from concrete, nickel alloy, carbon steel, and stainless steel with an internal coating/lining. The program consists of periodic visual inspections of internal coatings/linings exposed to closed-cycle cooling water, raw water, ~~secondary water, sulfuric acid, sodium hydroxide~~*demineralized water*, treated borated water, fuel oil, and lubricating oil. If certain criteria are met, alternatives to these visual inspections are available. Where the visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection. EPRI Report 1019157, "Guideline on Safety-Related Coatings," provides information on the ASTM standard guidelines and coatings. American Concrete Institute (ACI) Standard 201.1R-08, "Guide for Conducting a Visual Inspection of Concrete in Service," provides guidelines for inspecting concrete. Coating inspections and evaluations will be conducted by coating specialists qualified in accordance with an ASTM International standard endorsed in RG 1.54.

The Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is a new program that will be implemented no later than six months prior to the period of extended operation. Baseline internal coating/linings inspections will be conducted in the ten-year period prior to the period of extended operation. Subsequent inspections are based on an evaluation by a coating specialist of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Previous inspection results are reviewed prior to conducting subsequent inspections, and a post inspection report is prepared after inspections have been completed.

### LR-ISG-2013-01 Consistency

The Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is a new program that, when implemented, will be consistent *with exception to* ~~with~~ the recommendations of LR-ISG-2013-01.

**Exceptions to LR-ISG-2013-01**

~~None~~*LR-ISG-2013-01, Appendix C, Table 4a provides minimum inspection intervals. Due to 15 years of operating experience with acceptable results, inspection intervals for the Auxiliary Satwater system paraliner will be adjusted based on periodic inspection findings, trending, and evaluation by a qualified coating specialist using LR-ISG-2013-01 acceptance criteria. Inspection intervals will not exceed every fourth refueling outage.*

**Enhancements**

None

**Operating Experience**

The DCPP Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is a new program; therefore, plant-specific operating experience to verify the effectiveness of the program is not available. Industry operating experience that forms the basis for this program is included in the operating experience element of LR-ISG-2013-01.

**Conclusion**

The implementation of the Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, 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.

# Regulatory Commitments

Pacific Gas and Electric Company (PG&E) is making the following new regulatory commitment (as defined by NEI 99-04) in this submittal:

| Commitment | Due Date |
|---|---|
| PG&E is currently in the design phase of upgrading its cathodic protection system on buried, in-soil auxiliary saltwater system piping and is further evaluating the feasibility of protecting all subject piping. For some small portions, it may be impractical to install cathodic protection. PG&E will update the cathodic protection licensing basis by December 31, 2015. | December 31, 2015 |