Diablo Canyon Power Plant LRA Changes
Reflected in the Annual LRA Update Amendment 48

Attachment 18 of this enclosure includes a list of acronyms used in the 10 CFR 54.21(b) portion of this submittal.

Attachment	LRA Section	Subject
1	None	LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," Revision 1
2	None	LR-ISG-2011-02, "Aging Management Program for Steam Generators"
3 15	Table 3.3.2-3 Table 3.3.2-13 Section A1.18 Table A4-1 (52)	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'"
4 15	Section 3.1.2.1.1 Section 3.1.2.2.6 Section 3.1.2.2.9 Section 3.1.2.2.12 Section 3.1.2.2.15 Section 3.1.2.2.17 Table 3.1.1 Table 3.1.2-1 Section 4.3.3 Section A1.41 Table A4-1 (22, 72, and 73) Section B1.5 Section B2 Section B2.1.41	LR-ISG-2011-04, "Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors"
5 15	Section A1 Table A4-1 (20)	LR-ISG-2011-05, "Ongoing Review of Operating Experience"
6 15	Table 3.2.2-1 Table 3.2.2-3 Table 3.3.2-3 Table 3.3.2-8 Table 3.4.2-3 Table 3.4.2-5 Section A1.6	LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms"

Attachment	LRA Section	Subject
7 15	Section 3.2.2.1.1 Section 3.2.2.1.4 Section 3.2.2.1.5 Section 3.2.2.1.9 Table 3.2.2-1 Table 3.2.2-4 Table 3.3.1 Section 3.3.2.1.5 Section 3.3.2.1.9 Section 3.3.2.1.12 Section 3.3.2.1.19 Section 3.3.2.2.10.6 Table 3.3.2.1-19 Table 3.3.2-4 Table 3.3.2-5 Table 3.3.2-9 Table 3.3.2-10 Table 3.3.2-11 Table 3.3.2-12 Table 3.3.2-18 Section 3.4.2.1.5 Table 3.4.2-1 Table 3.4.2-3 Table 3.4.2-5 Section A1.13 Section A1.20 Section A1.22 Table A4-1 (8, 9, and 3)	LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"

Attachment	LRA Section	Subject
8 15	Section 3.3.2.1.3 Section 3.3.2.1.4 Section 3.3.2.1.5 Section 3.3.2.1.8 Section 3.3.2.1.12 Section 3.3.2.1.13 Table 3.3.2-3 Table 3.3.2-4 Table 3.3.2-5 Table 3.3.2-8 Table 3.3.2-12 Table 3.3.2-13 Section 3.4.2.1.4 Table 3.4.2-4 Section A1.9 Section A1.10 Section A1.13 Section A1.22 Table A4-1 (74)	Draft LR-ISG-2013-01, "Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings"
9 15	Section 2.1.2.2 Section 2.3.2.4 Table 3.3.2-3 Table 3.3.2-5 Table 3.3.2-7 Table 3.3.2-8 Table 3.3.2-9 Table 3.3.2-11 Table 3.3.2-12 Table 3.3.2-18 Table 3.4.2-1 Section A1.18	Update to reflect a review of plant equipment and editorial corrections.
10	Table 3.4.2-4	Update to remove caustic dilution heat exchanger tubes exposed to secondary water from scope of license renewal.
11	Table 4.3-1 Table 4.3-6 Section 4.9	Update to reflect WCAP-17103 revisions that addressed Regulatory Issues Summary 2011-14 regarding user intervention in Westems™.
12	Section 4.7.4 Section 4.9	License Amendments 216 (Unit 1) and 218 (Unit 2), which revised the reactor coolant pump flywheel inspection interval from 10 to 20 years in accordance with WCAP-15666A.
13 15	Section A1.6	Flow-Accelerated Corrosion program revision to address NSAC-202L-R4.

Attachment	LRA Section	Subject
14	Section 2.1.5	Update to address LR-ISG-2011-01 through -05; LR-ISG-2012-01; LR-ISG-2012-02, and LR-ISG-2013-01.
15	Section A1 Section A1.2 Section A1.6 Section A1.9 Section A1.10 Section A1.12 Section A1.13 Section A1.15 Section A1.16 Section A1.18 Section A1.20 Section A1.22 Section A1.32 Section A1.41 Table A4-1 (3, 8, 9, 20, 22, 32, 48, 52, 64, 66, 68, 72, 73, and 74)	All Updates to Final Safety Analysis Report Supplement.
16 15	Section A1.16 Table A4-1 (48)	One-Time Inspection Program Sample Size
17 15	Section A1.15	Reactor Vessel Surveillance Program: PG&E's Participation in EPRI PWR Supplemental Surveillance Program
18	None	Acronym List
19	None	References

LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," Revision 1

LR-ISG-2011-01 recommends two actions of the licensee to manage the effects of aging during the PEO for stainless steel structures and components exposed to treated borated water within the scope of license renewal. The following identifies the two actions and the results of PG&E's evaluation for impact on its LRA.

LR-ISG-2011-01 Action 1

Add the One-Time Inspection program to verify the effectiveness of the Water Chemistry program to manage loss of material due to pitting and crevice corrosion and cracking due to stress corrosion cracking in treated borated water. This revised guidance applies to stainless steel structures and components exposed to treated borated water environments that are not actively controlled to oxygen levels less than 5 ppb.

PG&E Evaluation of LR-ISG-2011-01 Action 1

Except for abandoned-in-place components associated with the boric acid evaporator subsystem, the following LRA tables currently specify the Water Chemistry and One-Time Inspection programs to manage aging of stainless steel structures and components exposed to treated borated water:

(1) Table 3.1.2-2 (Reactor Coolant System)
(2) Table 3.2.2-1 (Safety Injection System)
(3) Table 3.2.2-2 (Containment Spray System)
(4) Table 3.2.2-3 (Residual Heat Removal System)
(5) Table 3.3.2-1 (Cranes and Fuel Handling System)
(6) Table 3.3.2-2 (Spent Fuel Pool Cooling System)
(7) Table 3.3.2-4 (Component Cooling Water System)
(8) Table 3.3.2-6 (Nuclear Steam Supply Sampling System)
(9) Table 3.3.2-8 (Chemical Volume and Control System)
(10) Table 3.3.2-17 (Liquid Radwaste System), and
(11) Table 3.3.2-18 (Miscellaneous Systems In Scope Only for Criterion 10 CFR 54.4(a)(2))

As stated 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, (LRA Table 3.3.2-8, Plant-Specific Note 9, and LRA Table 3.3.2-18, Plant-Specific Note 7), abandoned-in-place components associated with the boric acid evaporator subsystem will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. As discussed in LRA Section B2.1.22, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will provide for periodic inspection of a representative sample of the internal surfaces material and environment combinations for systems within the scope of this program. The internal surfaces inspections will normally be performed through scheduled preventive maintenance and surveillance inspections such that work opportunities will be sufficient to detect aging and provide reasonable assurance that intended functions are maintained. Supplemental inspections not performed concurrently with planned work activities may also be performed. The locations and intervals for these supplemental inspections will be based on assessments of the potential for degradation which could lead to loss of intended function, and on current industry and plant-specific operating experience.

In conclusion, PG&E's LRA is consistent with LR-ISG-2011-01, Action 1, except for abandoned-in-place components associated with the boric acid evaporator subsystem as discussed above.

LR-ISG-2011-01 Action 2

Add reduction of heat transfer due to fouling as an aging effect for stainless steel heat exchanger tubes exposed to treated borated water, and manage this aging effect with the Water Chemistry and One-Time Inspection programs. As discussed in the ISG, the NRC Staff added reduction of heat transfer due to fouling as an aging effect requiring management with the Water Chemistry and One-Time Inspection programs for stainless steel heat exchanger tubes in the containment spray system, emergency core cooling system, spent fuel pool cooling and cleanup, and chemical and volume control system. The NRC Staff also noted that the current guidance for the containment spray system already includes a reduction of heat transfer item; however, the cited environment is treated water.

PG&E Evaluation of LR-ISG-2011-01 Action 2

As noted in the following LRA tables, stainless steel heat exchanger tubes with a reduction of heat transfer due to fouling aging effect currently require management with the Water Chemistry and One-Time Inspection programs.

(1) Table 3.2.2-1 (Safety Injection)
(2) Table 3.2.2-3 (Residual Heat Removal System)
(3) Table 3.3.2-2 (Spent Fuel Pool Cooling System)
(4) Table 3.3.2-4 (Component Cooling Water), and
(5) Table 3.3.2-8 (Chemical Volume and Control System)

DCPP has no in-scope stainless steel heat exchanger tubes exposed to treated borated water in the containment spray system.

In conclusion, PG&E is consistent with LR-ISG-2011-01, Action 2.

LR-ISG-2011-02, "Aging Management Program for Steam Generators"

LR-ISG-2011-02 evaluates the suitability of using Revision 3 of NEI 97-06 to manage steam generator aging. In addition, the LR-ISG corrects an incorrect revision in NUREG-1801, Revision 2, to the Steam Generator Integrity Assessment Guidelines.

PG&E's licensing basis for DCPP's Steam Generator Tube Integrity program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-073, dated July 7, 2010
(3) PG&E Letter DCL-10-122, dated September 22, 2010

The NRC Staff evaluated the DCPP Steam Generator Tube Integrity program in its SER, Section 3.0.3.1.6, dated June 2, 2011.

The NRC Staff is recommending that applicants for license renewal follow the guidance provided in Revision 3 of NEI 97-06 when implementing their steam generator AMP, including using Revision 3 of the Steam Generator Integrity Assessment Guidelines.

The DCPP Steam Generator Tube Integrity program establishes and maintains the program consistent with NEI 97-06, Revision 3, and the referenced EPRI guidelines. The Steam Generator Tube Integrity program also utilizes EPRI 1019038, "Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines, Revision 3."

In conclusion, PG&E is consistent with LR-ISG-2011-02.

LR-ISG-2011-03, "Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, 'Buried and Underground Piping and Tanks'"

LR-ISG-2011-03 contains recommended inspections, sample sizes, and inspection frequencies for GALL Report AMP XI.M41, "Buried Piping and Underground Piping and Tanks."

PG&E's licensing basis for the DCPP Buried and Underground Piping and Tanks program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-097, dated August 2, 2010
(3) PG&E Letter DCL-10-113, dated August 30, 2010
(4) PG&E Letter DCL-10-148, dated November 24, 2010
(5) PG&E Letter DCL-11-002, dated January 21, 2011
(6) PG&E Letter DCL-11-022, dated March 14, 2011

The NRC Staff evaluated the DCPP Buried and Underground Piping and Tanks program in its SER, Section 3.0.3.2.8, dated June 2, 2011.

In order to address the recommendations in LR-ISG-2011-03, PG&E updates its licensing basis for the DCPP Buried Piping and Tanks Inspection and External Surfaces Monitoring programs as follows. The ISG-recommended changes to the Selective Leaching program were evaluated and determined not to be applicable to DCPP since the buried components in-scope of the DCPP Selective Leaching program do not have cathodic protection or coatings.

(1) As discussed in PG&E Letter DCL-10-148, PG&E indicated that the in-scope buried piping of the makeup water system consists of asbestos cement pipe and a short segment of in scope, non-cathodically protected carbon steel piping contained inside a valve pit in contact with soil. PG&E Letter DCL-11-002 removed the non-cathodically protected carbon steel piping inside a valve pit in contact with soil from the scope of license renewal. Inspection of the in-scope makeup water asbestos cement pipe will be conducted as defined in LR-ISG-2011-03, Appendix A, Table 4a for cementitious material.

As discussed in PG&E Letter DCL-10-097, the in-scope buried makeup water system valves consisted of non-cathodically protected buried copper valves and copper valves in a valve pit in contact with soil. PG&E Letter DCL-11-002 removed the valves inside a valve pit in contact with soil from the scope of license renewal. PG&E Letter DCL-11-022 noted that the remaining in-scope buried non-cathodically protected makeup water valves were not copper, but cast iron. PG&E will inspect the non-cathodically protected makeup water system cast iron valves buried in soil in accordance with LR-ISG-2011-03, Appendix A, Table 4a. As discussed in SER Section 3.0.3.2.8, "although the cast iron valves are not cathodically protected, the DCPP Buried Piping and Tanks Inspection program will adequately manage aging of them because cast iron valves are thicker than piping or comparable steel valves and have a higher tolerance to general corrosion, and the valves are located in a nonaggressive soil environment." For the purposes of this program the aging management requirements for buried steel will be applied to these cast iron valves.

PG&E has evaluated the in-scope makeup water system carbon steel piping and tanks encased in concrete and determined there are no aging effects for these components. See Item (11) below.

As discussed in SER Sections 3.0.3.2.8 and 3.0.3.2.18, groundwater testing confirmed that DCPP's groundwater and soil environment was nonaggressive. As discussed in LRA Section B.2.1.32 and Table A4-1, Item 14 of PG&E Letter DCL-09-079, DCPP will monitor groundwater samples every five years for pH, sulfates and chloride concentrations, including consideration for potential seasonal variations. In addition, PG&E will perform a soil analysis prior to entering the PEO to determine the corrosivity of the soil in the vicinity of non-cathodically protected in-scope makeup water cast iron valves. If the initial analysis shows the soil to be non-corrosive, this analysis will be re-performed every ten years thereafter. Item (2) below discusses inspection intervals for steel components in the areas where soil analysis finds the soil to be corrosive.

(2) As discussed in PG&E Letter DCL-10-148, PG&E indicated that the in-scope buried ASW piping consists of cathodically protected steel piping and non-cathodically protected steel piping. PG&E committed to installing cathodic protection on a portion of the non-cathodically protected ASW discharge steel piping that is not encased in concrete prior to the PEO. PG&E also indicated that the cathodic protection systems of the ASW piping will be available more than 90 percent of the time.

PG&E revises the licensing basis in PG&E Letter DCL-10-148 as follows. If cathodic protection for the ASW steel piping meets the acceptance criteria in LR-ISG-2011-03, Appendix A, Table 4a, Footnote 2.C, including a revised system availability of 85 percent, then inspection of the in-scope cathodically protected ASW steel piping will be conducted consistent with LR-ISG-2011-03, Appendix A, Table 4a, Preventive Action C, with the number of inspections not to exceed 150 percent of the not to exceed values listed in the table.

If cathodic protection for the cathodically-protected ASW steel piping does not meet acceptance criteria (LR-ISG-2011-03, Appendix A, Table 4a, Footnote 2.C), PG&E will revise the scope of inspections as defined in LR-ISG-2011-03, Appendix A, Table 4a, Preventive Actions D, E, or F, with the number of inspections not to exceed 150 percent of the not to exceed values listed in the table. As defined in LR-ISG-2011-03, Appendix A, Table 4a, Notes 2E and 7, soil samples will determine which Preventive Action (D, E, or F) is required. These samples will be obtained and tested consistent with LR-ISG-2011-03, Table 4a, Note 7. If the soil is demonstrated not to be corrosive to buried steel piping, the number of inspections will be based on LR-ISG-2011-03, Table 4a, Preventive Action E. If the soil is determined to be corrosive to buried steel piping, then the number of inspections will be based on LR-ISG-2011-03, Table 4a, Preventive Action F.

As discussed in PG&E Letter DCL-10-148, ASW system piping that will not be cathodically protected is encased in concrete. The concrete provides a noncorrosive environment for the steel piping such that cathodic protection is not necessary and there are no aging effects. As discussed in PG&E Letter DCL-10-148, DCPP operating experience confirms effectiveness of this design.

PG&E has evaluated the in-scope ASW system stainless steel piping encased in concrete and determined there are no aging effects for these components. See Item (11) below.

(3) Consistent with LR-ISG-2011-03, Appendix A, Table 2b, the in-scope underground copper piping and piping components in the ASW system are coated. Inspections will be conducted to detect external corrosion in the underground copper piping, and piping components, and PVC piping in the ASW system as defined in LR-ISG-2011-03, Appendix A, Table 4b. Visual inspections of PVC piping will be augmented with manual examinations to detect hardening, softening, or other changes in material properties.

(4) The ASW system also contains buried portions of super austenitic stainless steel piping. This piping is in the scope of the Buried Piping and Tanks Inspection program. However, LR-ISG-2011-03, Appendix A, Table 4a, does not require any inspections on buried super austenitic stainless steel.

(5) As discussed in PG&E Letters DCL-10-113 and DCL-10-148, the buried diesel fuel oil storage tanks are double walled steel with the exterior surface wrapped in a corrosion resistant fiberglass reinforced plastic. As discussed in PG&E Letter DCL-10-113, PG&E indicated that the buried diesel fuel oil storage tanks are equipped to monitor the space between the inner and outer walls for leakage. SER Section 3.0.3.2.8 discusses the acceptability of this

monitoring method to adequately manage the aging of the tanks. As allowed by LR-ISG 2011-03, Appendix A, Section 4.d.iv, PG&E will monitor the condition of the buried diesel fuel oil storage tanks by monitoring the space between the inner and outer walls for leakage.

As discussed in PG&E Letter DCL-10-148, PG&E indicated that 100 percent of the underground diesel generator fuel oil system piping is visually inspected by an existing plant procedure on a ten-year interval and that this existing plant procedure would be incorporated into the DCPP External Surfaces Monitoring program. To address LR-ISG 2011-03, Appendix E, PG&E will remove the underground diesel fuel oil piping inspections from the scope of the DCPP External Surfaces Monitoring program. The DCPP Buried Piping and Tanks Inspection program will describe this inspection and the associated ten-year frequency.

(6) Consistent with the LR-ISG-2011-03, Section titled, "Removal of the Recommendation to Volumetrically Inspect Underground Piping to Detect Corrosion," PG&E revises the commitment in PG&E Letter DCL-10-148 to perform nondestructive examinations during visual inspections of piping to be consistent with LR-ISG-2011-03, Appendix A, Section 4.b.iv, which requires supplemental surface and/or volumetric NDT of buried piping only if significant indications are observed.

(7) PG&E will double the initial inspection size following discovery of adverse conditions and will manage subsequent discoveries of adverse conditions as defined in LR-ISG-2011-03, Appendix A, Sections 4.f.iii and 4.f.iv.

(8) Consistent with LR-ISG-2011-03, Appendix A, Section 6.b, PG&E will evaluate the extent of condition where damage to the coating is significant and the damage was caused by nonconforming backfill to ensure the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. In addition, PG&E will qualify personnel performing inspection of coatings on buried piping consistent with LR-ISG-2011-03, Appendix A, Section 6.b.

(9) In lieu of visual inspections of the external surface of buried piping requiring excavation, PG&E may perform hydrostatic testing or internal inspections of the pipe consistent with LR-ISG-2011-03, Appendix A, Section 4.b.x.

(10) As discussed in PG&E Letter DCL-10-148, PG&E indicated that the 850-mV criteria from NACE SP0169-07, paragraph 6.2.2 are used for the ASW piping cathodic protection test locations where static (native) pipe-to-soil potential data is not available and that the 100-mV criteria are used for the ASW pipe test locations where static (native) pipe-to-soil potential data is available.

PG&E will use the 850-mV polarized potential relative to a copper sulfate electrode cathodic protection acceptance criteria as defined in LR-ISG-2011-03, Appendix A, Table 6a.

(11) Consistent with NUREG-1800, Revision 2, Items 3.3.1-112 and 3.3.1-120, PG&E has evaluated the steel and stainless steel piping, piping components, piping elements, and tanks encased in concrete and determined there are no aging effects for these components. There are floor and equipment drains, piping, and tanks encased in concrete. A majority of the piping and components are within buildings where the potential for water intrusion into the concrete is very low, and therefore the conditional statements associated with NUREG-1800, Revision 2, Item 3.3.1-112 provide a sufficient basis of no aging effects. The remainder of the piping encased in concrete is the ASW discharge. PG&E has previously provided justification for the lack of aging effects for this ASW piping in PG&E Letter DCL-10-148. There has been no DCPP operating experience to show that metallic components embedded in concrete experience any aging effects.

(12) As discussed in PG&E Letter DCL-10-148, PG&E committed to inspecting buried PVC and asbestos cement pipe components located in the fire water system (LRA Table A4-1, Item 52). PG&E also committed to subjecting fire mains 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 firewater pipe for visual inspections. SER Section 3.0.3.2.8 discusses the sufficiency of this flow testing to adequately manage the aging of the buried fire water piping.

As concluded in SER Section 3.0.3.2.8 and allowed by LR-ISG-2011-03, Appendix A, Section 4.b.ix, in-scope buried fire water piping and components (including PVC and asbestos cement pipe) will be managed by subjecting fire mains to periodic flow tests in accordance with NFPA 25, Section 7.3, at a frequency of at least one test in each one-year period. Although no directed visual inspections of the in-scope buried fire water system piping will be completed through the DCPP Buried Piping and Tanks Inspection program, buried piping will be inspected opportunistically as it is excavated. Additionally, opportunistic internal visual inspections will be conducted through the DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and periodic internal visual inspections will be conducted through the DCPP Fire Water System program.

As discussed in SER Sections 3.0.3.2.8 and 3.0.3.2.18, groundwater testing confirmed that DCPP's groundwater and soil environment was nonaggressive. As discussed in LRA Section B.2.1.32 and Table A4-1, Item 14 of PG&E Letter DCL-09-079, DCPP will monitor groundwater samples every five years for pH, sulfates and chloride concentrations, including consideration for potential seasonal variations. In addition, PG&E will perform a soil analysis prior to entering the PEO to determine the corrosivity of the soil in the vicinity of non-cathodically protected steel in-scope buried fire water piping and components. If the initial analysis shows the soil to be noncorrosive, this analysis will be re-performed every ten years thereafter. If the soil is found to be corrosive, the effect on the pipe will be evaluated to determine if aging management of the buried pipe and valves is adequate.

LRA Tables 3.3.2-3 and 3.3.2-13 are revised to address LR-ISG-2011-03 as shown in this Attachment.

LRA Section A1.18 and Table A4-1, Item 52 are revised to address LR-ISG-2011-03 as shown in Enclosure 1, Attachment 15.

Table 3.3.2-3 Auxiliary Systems – Summary of Aging Management Evaluation – Saltwater and Chlorination System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	*LBS, PB*	*Copper Alloy*	*Plant Indoor Air (Ext)*	*Loss of material*	*Buried Piping and Tanks Inspection (B2.1.18)*	*None*	*None*	*H, 3*
Piping	*LBS, SIA*	*Polyvinyl Chloride (PVC)*	*Plant Indoor Air (Ext)*	*Loss of material*	*Buried Piping and Tanks Inspection (B2.1.18)*	*None*	*None*	*H, 3*
Valve	*LBS, PB*	*Copper Alloy*	*Plant Indoor Air (Ext)*	*Loss of material*	*Buried Piping and Tanks Inspection (B2.1.18)*	*None*	*None*	*H, 3*

Notes for Table 3.3.2-3:

Plant Specific Notes:

3 The Buried Piping and Tanks Inspection (B2.1.18) is used to monitor underground copper alloy piping, pipe components, and PVC piping for loss of material. Reference LR-ISG-2011-03, Appendix C, Item VII.I.AP-284 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 3.

Table 3.3.2-13 Auxiliary Systems – Summary of Aging Management Evaluation – Diesel Generator Fuel Oil 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	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	~~External Surfaces Monitoring Program (B2.1.20)~~*Buried Piping and Tanks Inspection (B2.1.18)*	VII.I-8	3.3.1.58	~~B~~*H, 2*
Tank	PB	Carbon Steel	Plant Indoor Air (Int)	Loss of material	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~*Buried Piping and Tanks Inspection (B2.1.18)*	VII.H2-21	3.3.1.71	~~D~~*H, 2*
Piping	*PB*	*Carbon Steel*	*Plant Indoor Air (Ext)*	*Loss of material*	*Buried Piping and Tanks Inspection (B2.1.18)*	*VII.I-8*	*3.3.1.58*	*H, 2*

Notes for Table 3.3.2-13:

Plant Specific Notes:

2 The Buried Piping and Tanks Inspection (B2.1.18) is used to monitor the underground diesel generator fuel oil system piping for loss of material. Reference LR-ISG-2011-03, Appendix C, VII.I.AP-284 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 3.

LR-ISG-2011-04, "Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors"

PG&E's licensing basis for the DCPP PWR Vessel Internals program is documented in:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-098, dated August 2, 2010
(3) PG&E Letter DCL-10-121, dated September 22, 2010
(4) PG&E Letter DCL-10-167, dated January 12, 2011

In order to address the recommendations in LR-ISG-2011-04 and NUREG-1801, Revision 2, for reactor vessel internals, PG&E updates its licensing basis as follows:

As discussed in PG&E Letter DCL-09-079, LRA Table A4-1, Item 22, for Reactor Vessel Internals, PG&E previously committed to:

(1) participate in the industry programs for investigating and managing aging effects on reactor internals;

(2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and

(3) upon completion of these programs, but not less than 24 months before entering the PEO, PG&E will submit an inspection plan for reactor internals to the NRC for review and approval. PG&E will validate the schedule for inspection of the baffle and former bolts on a plant-specific basis to ensure that it will appropriately manage the design fatigue analysis.

In January 2012, MRP-227-A (EPRI TR-1022863), "Materials Reliability Program: Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," was issued. MRP-227-A is the NRC-endorsed version of MRP-227, which incorporates the NRC Staff's SE, Revision 1, on MRP-227. LR-ISG-2011-04 revises the recommendations in the GALL Report, Revision 2, and the NRC Staff's acceptance criteria and review procedures in the SRP-LR to ensure consistency with MRP-227-A.

To address the issuance of MRP-227-A and LR-ISG-2011-04, PG&E:

(1) Developed LRA Section B2.1.41 consistent with GALL Report, Revision 2, XI.M16A and LR-ISG-2011-04.

(2) Developed LRA Section A1.41 to describe the DCPP PWR Vessel Internals program.

(3) Deleted LRA Table A4-1, Item 22, for Reactor Vessel Internals.

(4) Added LRA Table A4-1, Item 72, to implement the DCPP PWR Vessel Internals program (B2.1.41) prior to the PEO.

(5) Added LRA Table A4-1, Item 73, to submit responses to the applicable AMP plant-specific action items, conditions, and limitations identified in the NRC SE, Revision 1, on MRP-227 by December 2015. In addition to developing an AMP, the NRC SE for MRP-227 contains eight action items for applicants/licensees to consider. Responses to the applicable AMP plant-specific action items, conditions, and limitations identified in the NRC SE, Revision 1, on MRP-227 will be submitted to the NRC by December 2015.

(6) Incorporated GALL Report, Revision 2, Table IV.B2, for PWR vessel internals and LR-ISG-2011-04 into DCPP reactor vessel internal components' AMR results in revised LRA Tables 3.1.1 and 3.1.2-1, and Sections 3.1.2.1.1, 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17.

Revised LRA Tables 3.1.1 and 3.1.2-1, and Sections 3.1.2.1.1, 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, 3.1.2.2.17, 4.3.3, B1.5, B2, and new Section B2.1.41 are shown in this Attachment.

New LRA Section A1.41, revised Table A4-1, Item 22, for Reactor Vessel Internals, and new Table A4-1, Items 72 and 73 are shown in Attachment 15.

3.1.2.1.1 Reactor Vessel and Internals

Environment

- *Neutron flux*

Aging Management Programs

- *PWR Vessel Internals (B2.1.41)*

~~For Reactor Vessel Internals, PG&E will:~~
~~(1) Participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, PG&E will submit an inspection plan for reactor internals to the NRC for review and approval.~~

3.1.2.2.6 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement and Void Swelling

Not applicable. The DCPP PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in EPRI TR-1022863 (MRP-227-A) and EPRI TR-1016609 (MRP-228) to manage the aging effects of selected reactor vessel internal components.~~Loss of fracture toughness due to neutron irradiation embrittlement and void swelling for stainless steel reactor internals components exposed to reactor coolant will be managed by (1) participating in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluating and implementing the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submitting an inspection plan for reactor internals to the NRC for review and approval.~~

3.1.2.2.9 Loss of Preload due to Stress Relaxation

Not applicable. The DCPP PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in EPRI TR-1022863 (MRP-227-A) and EPRI TR-1016609 (MRP-228) to manage the aging effects of selected reactor vessel internal components.~~Loss of preload due to stress relaxation for nickel-alloy and stainless steel reactor internals components exposed to reactor coolant will be managed by (1) participating in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluating and implementing the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submitting an inspection plan for reactor internals to the NRC for review and approval.~~

3.1.2.2.12 Cracking due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

Not applicable. The DCPP PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in EPRI TR-1022863 (MRP-227-A) and EPRI TR-1016609 (MRP-228) to manage the aging effects of selected reactor vessel internal components.~~For managing the aging of cracking due to stress corrosion cracking and irradiation-assisted stress corrosion cracking of stainless steel reactor internals components exposed to reactor coolant, Water Chemistry (B2.1.2) is augmented by (1) participating in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluating and implementing the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submitting an inspection plan for reactor internals to the NRC for review and approval.~~

3.1.2.2.15 Changes in dimensions due to Void Swelling

Not applicable. The DCPP PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in EPRI TR-1022863 (MRP-227-A) and EPRI TR-1016609 (MRP-228) to manage the aging effects of selected reactor vessel internal components.~~Changes in dimensions due to void swelling for stainless steel reactor internals components exposed to reactor coolant will be managed by (1) participating in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluating and implementing the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submitting an inspection plan for reactor internals to the NRC for review and approval.~~

3.1.2.2.17 Cracking due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

Not applicable. The DCPP PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in EPRI TR-1022863 (MRP-227-A) and EPRI TR-1016609 (MRP-228) to manage the aging effects of selected reactor vessel internal components.~~For managing the aging of cracking due to stress corrosion cracking, primary water stress corrosion cracking, and irradiation-assisted stress corrosion cracking of stainless steel reactor internals components exposed to reactor coolant, Water Chemistry (B2.1.2) will be augmented by (1) participating in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluating and implementing the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submitting an inspection plan for reactor internals to the NRC for review and approval.~~

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1.22	Stainless steel ~~*(SS, including CASS, PH SS or martensitic SS)*~~ *or*~~and~~ nickel alloy *Westinghouse* reactor vessel internal~~s~~ *"Existing Programs"* components ~~exposed to reactor coolant and neutron flux~~	Loss of fracture toughness due to ~~*thermal aging and*~~ neutron irradiation embrittlement *and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement;*~~,~~ *or changes in dimensions due to* void swelling *or distortion; or loss of preload due to thermal and irradiation enhanced stress relaxation or irradiation enhanced creep; or loss of material due to wear*	*PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*. ~~See further evaluation in Section 3.1.2.2.6.~~
3.1.1.27	Stainless steel ~~*(SS, including CASS, PH SS or martensitic SS)*~~ *or*~~and~~ nickel alloy *Westinghouse* reactor vessel internal~~s~~ *"Expansion" components*~~screws, bolts, tie rods, and hold-down springs~~	*Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or changes in dimensions due to void swelling or distortion; or* ~~Loss~~ *loss* of preload due to *thermal and irradiation enhanced* stress relaxation *or irradiation enhanced creep; or loss of material due to wear*	*PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*. ~~See further evaluation in Section 3.1.2.2.9.~~

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1.30	Stainless steel *or nickel alloy Westinghouse* reactor vessel internal~~s~~ *"Primary"* components ~~(e.g., Upper internals assembly, RCCA guide tube assemblies, Baffle/former assembly, Lower internal assembly, shroud assemblies, Plenum cover and plenum cylinder, Upper grid assembly, Control rod guide tube (CRGT) assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly, Thermal shield, Instrumentation support structures)~~	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking*, or fatigue*	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*. ~~See further evaluation in Section 3.1.2.2.12.~~

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1.33	Stainless steel ~~(SS, including CASS, PH SS or martensitic SS)~~ *or*~~and~~ nickel alloy *Westinghouse* reactor vessel internal~~s~~ *"Primary"* components	*Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or c*~~C~~hanges in dimensions due to void swelling *or distortion; or loss of preload due to thermal and irradiation enhanced stress relaxation or irradiation enhanced creep; or loss of material due to wear*	*PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*. ~~See further evaluation in Section 3.1.2.2.15.~~
3.1.1.37	Stainless steel ~~and~~ *or* nickel alloy *Westinghouse* reactor vessel internal~~s~~ *"Existing Programs"* components ~~(e.g., Upper internals assembly, RCCA guide tube assemblies, Lower internal assembly, CEA shroud assemblies, Core shroud assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly)~~	Cracking due to stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking*, or fatigue*	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*. ~~See further evaluation in Section 3.1.2.2.17.~~

Table 3.1.1 Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1.63	Steel reactor vessel flange, stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (e.g., upper and lower internals assembly~~, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, lower grid assembly~~)	*Cracking or* Loss of material due to Wear	Inservice Inspection (IWB, IWC, and IWD) (B2.1.1) *or PWR Vessel Internals (B2.1.41)*	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04*
3.1.1.80	*Stainless steel Westinghouse reactor vessel internal "Expansion" components*~~Cast austenitic stainless steel reactor vessel internals (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, lower grid assembly)~~	*Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue*~~Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement~~	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*~~Thermal Aging and Neutron Irradiation Embrittlement of CASS (B2.1.39)~~	No	Consistent with NUREG-1801*, Revision 2, and LR-ISG-2011-04.*~~ for material, environment, and aging effect, but a different aging management program FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on is credited.~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Baffle ~~&~~ *-to-* Former Assembly (Baffle Plates, Former Plates)	DF, SLD, SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Changes in dimensions	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-270* ~~1~~	3.1.1.33	A, *3*
RVI Baffle ~~&~~ *-to-* Former Assembly (Baffle Plates, Former Plates)	DF, SLD, SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-270a* ~~2~~	3.1.1.30	A, *3*
~~RVI Baffle & Former Assembly (Baffle Plates, Former Plates)~~	~~DF, SLD, SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-3~~	~~3.1.1.22~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Baffle~~ & ~~*-to-* Former Assembly (Baffle/ Former Bolts)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Changes in dimensions	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-272*~~-4~~	3.1.1.33	A, *3*
RVI Baffle~~ & ~~*-to-* Former Assembly (Baffle/ Former Bolts)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of preload	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-272*~~-5~~	3.1.1.~~27~~*33*	A, *3*
RVI Baffle~~ & ~~*-to-* Former Assembly (Baffle/ Former Bolts)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of fracture toughness	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-272*~~-6~~	3.1.1.~~22~~*33*	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Baffle ~~&~~ *to*-Former Assembly (Baffle/ Former Bolts)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-271*~~-10~~	3.1.1.30	A, *3*
RVI Baffle-to-Former Assembly (Baffle-edge-bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-275*	*3.1.1.30*	*A, 3*
RVI Baffle-to-Former Assembly (Baffle-edge-bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of fracture toughness*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-354*	*3.1.1.33*	*A, 3*
RVI Baffle-to-Former Assembly (Baffle-edge-bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of preload*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-354*	*3.1.1.33*	*A, 3*
RVI Baffle-to-Former Assembly (Baffle-edge-bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Changes in dimension*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-354*	*3.1.1.33*	*A, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~R~~VI Control Rod Guide Tube Assembly (Control Rod Guide Tubes/~~/Tube Support Pins/Guide Tube Bolts~~*Guide Plates (cards)*)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	~~Changes in dimensions~~ *Loss of material*	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2*.RP-296*~~-27~~	3.1.1.33	A*, 3*
~~RVI Control Rod Guide Tube Assembly (Control Rod Guide Tubes/Tube Support Pins/Guide Tube Bolts)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-28~~	~~3.1.1.37~~	~~A~~
~~RVI Control Rod Guide Tube Assembly (Control Rod Guide Tubes/Tube Support Pins/Guide Tube Bolts)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-29~~	~~3.1.1.33~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Control Rod Guide Tube Assembly (~~Control Rod Guide Tubes/Tube Support Pins/ Guide Tube Bolts~~*Lower Flange Welds*)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-298*~~-30~~	3.1.1.30	A, *3*
RVI Control Rod Guide Tube Assembly (Lower Flange Welds)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of fracture toughness*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-297*	*3.1.1.33*	*A, 3*
RVI ~~Control Rod Guide Tube Assembly (Control Rod Guide Tubes/*Lower Flange Welds*/Tube Support Pins/Guide Tube Bolts, *Guide Plates (cards)*)~~*Components*	*DF, SLD,* SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of material	Water Chemistry (B2.1.2)	IV.B2-32	3.1.1.83	A
RVI Control Rod Guide Tube Assembly (Guide Tube Bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.BP-382*	*3.1.1.63*	*A, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Control Rod Guide Tube Assembly (Guide Tube Bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of material*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.BP-382*	*3.1.1.63*	*A, 3*
RVI ~~Core Barrel~~*Baffle-to-Former* Assembly (*Barrel-to-Former Bolts*~~RVI Core Barrel, Core Barrel Outlet Nozzles, and Core Barrel Flange~~)	~~DF, SLD,~~ SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Changes in dimensions	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-274*~~-7~~	3.1.1.~~33~~*27*	A, *3*
RVI Baffle-to-Former Assembly (Barrel-to-Former Bolts)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of Preload*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-274*	*3.1.1.27*	*A, 3*
RVI *Baffle-to-Former*~~Core Barrel~~ Assembly (*Barrel-to-Former Bolts*~~RVI Core Barrel, Core Barrel Outlet Nozzles, and Core Barrel Flange~~)	~~DF, SLD,~~ SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-273*~~-8~~	3.1.1.~~30~~*80*	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI *Baffle-to-Former*~~Core Barrel~~ Assembly (*Barrel-to-Former Bolts*~~RVI Core Barrel, Core Barrel Outlet Nozzles, and Core Barrel Flange~~)	~~DF, SLD,~~ SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of fracture toughness	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2*.RP-274*~~-9~~	3.1.1.~~22~~*27*	A*, 3*
RVI Core Barrel Assembly (Core Barrel Flange)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of material*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.RP-382*	*3.1.1.63*	*A, 3*
RVI Core Barrel Assembly (Core Barrel Outlet Nozzles)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.RP-382*	*3.1.1.63*	*A, 3*
RVI Core Barrel Assembly (Core Barrel Outlet Nozzles)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of material*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.RP-382*	*3.1.1.63*	*A, 3*
RVI Core Barrel Assembly (Core Barrel Outlet Nozzle Welds)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-278*	*3.1.1.80*	*A, 3*
RVI Core Barrel Assembly (Core Barrel Outlet Nozzle Welds)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of fracture toughness*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-278a*	*3.1.1.27*	*A, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Core Barrel Assembly (Upper and Lower Core Barrel Girth Welds)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-387*	*3.1.1.30*	*A, 3*
RVI Core Barrel Assembly (Upper and Lower Core Barrel Axial Welds)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-387a*	*3.1.1.80*	*A, 3*
RVI Core Barrel Assembly (Upper and Lower Core Barrel Axial Welds)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Loss of fracture toughness*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-388a*	*3.1.1.27*	*A, 3*
RVI Core Barrel Assembly (Lower Core Barrel Flange Weld)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-280*	*3.1.1.30*	*A, 3*
RVI Core Barrel Assembly (Upper Core Barrel Flange Weld)	*DF, SLD, SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-276*	*3.1.1.30*	*A, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Core Barrel Assembly (RVI Core Barrel, Core Barrel Outlet Nozzles, and Core Barrel Flange)~~	~~DF, SLD, SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2)~~	~~IV.B2-32~~	~~3.1.1.83~~	~~A~~
RVI Hold Down Spring (RVI Hold Down Spring)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of preload	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-300*~~-33~~	3.1.1.~~27~~*33*	A*, 3*
RVI Hold Down Spring (RVI Hold Down Spring)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Changes in dimensions	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-300*~~-41~~	3.1.1.33	A*, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Hold Down Spring (RVI Hold Down Spring)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	*Loss of material*~~Cracking~~	~~Water Chemistry (B2.1.2) and~~ *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-300*~~-42~~	3.1.1.~~30~~*33*	A, *3*
Bottom-mounted instrumentation system: bottom-mounted instrumentation (BMI) column bodies~~RVI Instrumentation Support Structures (Flux Thimble Guide Columns and Bolts, Thermocouple Instrumentation Columns/ Conduit/Bolts)~~	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	*Loss of fracture toughness*~~Changes in dimensions~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-292*~~-11~~	3.1.1.~~33~~*27*	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bottom-mounted instrumentation system: bottom-mounted instrumentation (BMI) column bodies~~RVI Instrumentation Support Structures (Flux Thimble Guide Columns and Bolts, Thermocouple Instrumentation Columns/ Conduit/Bolts)~~	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-293*~~-12~~	3.1.1.~~30~~*80*	A, *3*
~~RVI Irradiation Specimen Basket (Vessel Irradiation Specimen Basket)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-20~~	~~3.1.1.37~~	~~C~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (Clevis Insert Bolts~~, Radial Keys, Clevis Insert Keyways~~)	SS	Nickel Alloys	Reactor Coolant *and neutron flux* (Ext)	Loss of preload	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-285*~~-14~~	3.1.1.~~27~~22	A, *3*
RVI Lower Core Support Structure (Clevis Insert Bolts~~, Radial Keys, Clevis Insert Keyways~~)	SS	Nickel Alloys	Reactor Coolant *and neutron flux* (Ext)	*Loss of material*~~Changes in dimensions~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-285*~~-15~~	3.1.1.~~33~~22	A, *3*
RVI Lower Core Support Structure (Clevis Insert Bolts)	*SS*	*Nickel Alloys*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-399*	*3.1.1.37*	*A, 3*
RVI Lower Core Support Structure (Radial Keys, Clevis Insert Keyways)	*SS*	*Nickel Alloys*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)*	*IV.B2.RP-382*	*3.1.1.63*	*C, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (~~Clevis Insert Bolts,~~ Radial Keys, Clevis Insert Keyways)	SS	Nickel Alloys	Reactor Coolant *and neutron flux* (Ext)	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.B2-~~34~~*RP-382*	3.1.1.63	C, *3*
RVI Lower Core Support Structure (~~Clevis Insert Bolts, Radial Keys, Clevis Insert Keyways~~*Core Support Column Bolts*)	SS	*Stainless Steel*~~Nickel Alloys~~	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-286*~~-16~~	3.1.1.~~37~~*80*	A, *3*
RVI Lower Core Support Structure (*Core Support Column Bolts*~~Clevis Insert Bolts, Radial Keys, Clevis Insert Keyways~~)	SS	*Stainless Steel*~~Nickel Alloys~~	Reactor Coolant *and neutron flux* (Ext)	Loss of fracture toughness	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2*RP-287*~~-17~~	3.1.1.~~22~~*27*	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (*Core Support Column Bolts*~~Clevis Insert Bolts, Radial Keys, Clevis Insert Keyways~~)	SS	*Stainless Steel*~~Nickel Alloys~~	Reactor Coolant *and neutron flux* (Ext)	*Loss of preload*~~Changes in dimensions~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-287*~~-19~~	3.1.1.~~33~~*27*	A, *3*
RVI Lower Core Support Structure (*Lower Support Column Bodies (non-cast)*~~Clevis Insert Bolts, Radial Keys, Clevis Insert Keyways~~)	SS	*Stainless Steel*~~Nickel Alloys~~	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-294*~~-20~~	3.1.1.~~37~~*80*	A, *3*
RVI Lower Core Support Structure (~~Fuel Alignment Pins, Core~~ *Lower* Support Column *Bodies (non-cast)* ~~& Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover~~)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	*Loss of fracture toughness*~~Changes in dimensions~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-295*~~-15~~	3.1.1.~~33~~*27*	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (Lower Support Column Bodies (cast))	*SS*	*Stainless Steel Cast Austenitic*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-291*	*3.1.1.80*	*A, 3*
RVI Lower Core Support Structure (Lower Support Column Bodies (cast))	*SS*	*Stainless Steel Cast Austenitic*	*Reactor Coolant and neutron flux (Ext)*	*Loss of fracture toughness*	*PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-290*	*3.1.1.27*	*A, 3*
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-16~~	~~3.1.1.37~~	~~A~~
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-17~~	~~3.1.1.22~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (Lower Core Plate)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of fracture toughness	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-288*~~-18~~	3.1.1.22	A, *3*
~~RVI Lower Core Support Structure (Flow Diffuser Plate (Unit 1))~~	~~DF~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-18~~	~~3.1.1.22~~	~~C~~
RVI Lower Core Support Structure (Lower Core Plate)	~~DF~~*SS*	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of ~~fracture toughness~~*material*	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-288*~~-18~~	3.1.1.22	A, *3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Lower Core Support Structure (Lower Core Plate)~~	~~DF~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-19~~	~~3.1.1.33~~	~~A~~
~~RVI Lower Core Support Structure (Flow Diffuser Plate (Unit 1))~~	~~DF~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-19~~	~~3.1.1.33~~	~~C~~
~~RVI Lower Core Support Structure (Lower Core Plate)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-19~~	~~3.1.1.33~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Lower Core Support Structure (Lower Core Plate)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-289*~~-20~~	3.1.1.37	A*, 3*
~~RVI Lower Core Support Structure (Lower Core Plate)~~	~~DF~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-20~~	~~3.1.1.37~~	~~A~~
~~RVI Lower Core Support Structure (Flow Diffuser Plate (Unit 1))~~	~~DF~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-20~~	~~3.1.1.37~~	~~C~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-22~~	~~3.1.1.22~~	~~A~~
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-23~~	~~3.1.1.33~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-24~~	~~3.1.1.30~~	~~A~~
~~RVI Lower Core Support Structure (Fuel Alignment Pins, Core Support Column & Bolts, Core Support Forging (U2), Lower Tie Plate (U2), Upper Tie Plate (U2), Manway Cover)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of preload~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-25~~	~~3.1.1.27~~	~~A~~
RVI Lower Core Support Structure (~~Core~~ *Lower* Support *Forging or* Casting ~~(U1)~~)	SS	Stainless Steel Cast Austenitic	Reactor Coolant *and neutron flux* (Ext)	Loss of fracture toughness	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-290a* ~~-21~~	3.1.1.~~80~~*27*	A~~E~~, 3

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Lower Core Support Structure (Core Support Casting (U1))~~	~~SS~~	~~Stainless Steel Cast Austenitic~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-23~~	~~3.1.1.33~~	~~A~~
RVI Lower Core Support Structure (~~Core~~ *Lower* Support *Forging or* Casting ~~(U1)~~)	SS	Stainless Steel Cast Austenitic	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-291a*~~-24~~	3.1.1.~~30~~*80*	A, *3*
~~RVI Thermal & Neutron Shield (Thermal (U1)/Neutron (U2) Shield and Bolting)~~	~~SLD~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-7~~	~~3.1.1.33~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Thermal ~~& Neutron~~ Shield *Assembly* (Thermal ~~(U1)/Neutron (U2) Shield and Bolting~~*Shield Flexures*)	SLD	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-302*~~-8~~	3.1.1.30	A, *3*
RVI Thermal ~~&~~ ~~Neutron~~ Shield *Assembly* (Thermal ~~(U1)/Neutron (U2) Shield and Bolting~~*Shield Flexures*)	SLD	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of *material*~~fracture toughness~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-302a*~~-9~~	3.1.1.~~22~~*33*	A, *3*
~~RVI Upper Core Support Structure (Upper Core Plate, Upper Support Plate, Upper Support Columns Bolts, Alignment Pins~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Loss of Material~~	~~ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~	~~IV.B2-34~~	~~3.1.1.63~~	~~A~~

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Upper Core Support Structure (Upper Core Plate~~, Upper Support Plate, Upper Support Columns Bolts, Alignment Pins~~)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Loss of *material*~~preload~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP. 290b*~~-38~~	3.1.1.27	A*, 3*
~~RVI Upper Core Support Structure (Upper Core Plate, Upper Support Plate, Upper Support Columns Bolts, Alignment Pins)~~	~~SS~~	~~Stainless Steel~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-39~~	~~3.1.1.33~~	~~A~~
RVI Upper Core Support Structure (Upper Core Plate~~, Upper Support Plate, Upper Support Columns Bolts, Alignment Pins~~)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	~~Water Chemistry (B2.1.2) and~~ *PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-291b*~~-40~~	3.1.1.~~37~~*80*	A*, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RVI Upper Core Support Structure (Upper Core Plate~~, Upper Support Plate, Upper Support Columns Bolts,~~ Alignment Pins)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	*Loss of material*~~Changes in dimensions~~	*PWR Vessel Internals (B2.1.41)* ~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-299*~~-41~~	3.1.1.~~33~~*22*	A, *3*
RVI Upper Core Support Structure (Upper Core Plate~~, Upper Support Plate, Upper Support Columns Bolts,~~ Alignment Pins)	SS	Stainless Steel	Reactor Coolant *and neutron flux* (Ext)	Cracking	Water Chemistry (B2.1.2) and *PWR Vessel Internals (B2.1.41)*~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	IV.B2.*RP-301*~~-42~~	3.1.1.~~30~~*37*	A, *3*
~~RVI Upper Core Support Structure (Upper Support Columns)~~	~~SS~~	~~Stainless Steel Cast Austenitic~~	~~Reactor Coolant (Ext)~~	~~Changes in dimensions~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-35~~	~~3.1.1.33~~	~~A, 3~~
RVI Upper Core Support Structure (Upper Support Ring or Skirt)	*SS*	*Stainless Steel*	*Reactor Coolant and neutron flux (Ext)*	*Cracking*	*Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.41)*	*IV.B2.RP-346*	*3.1.1.37*	*A, 3*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~RVI Upper Core Support Structure (Upper Support Columns)~~	~~SS~~	~~Stainless Steel Cast Austenitic~~	~~Reactor Coolant (Ext)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-36~~	~~3.1.1.30~~	~~A~~
~~RVI Upper Core Support Structure (Upper Support Columns)~~	~~SS~~	~~Stainless Steel Cast Austenitic~~	~~Reactor Coolant (Ext)~~	~~Loss of fracture toughness~~	~~FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.~~	~~IV.B2-37~~	~~3.1.1.80~~	~~E, 3~~

Notes for Table 3.1.2-1:

Plant Specific Notes:

3. ~~The commitment to implement the RVI inspection plan will manage this aging effect.~~ *Line item was revised to align with NUREG-1801, Revision 2, and LR-ISG-2011-04. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 4.*
4. ~~The commitment to implement the RVI inspection plan~~ *PWR Vessel Internals (B2.1.41)* will manage fatigue of the Baffle-Former Bolts in the Reactor Vessel Internals Baffle and Former Assembly

4.3.3 Fatigue Analyses of the Reactor Pressure Vessel Internals

Summary Description

The structural adequacy of the reactor internals is discussed in FSAR Section 3.9.3.4.1. The reactor internal components are not ASME code components. The reactor internals were designed and built prior to the implementation of Subsection NG of the ASME Boiler and Pressure Vessel Code, Section III, for reactor vessel internals. Therefore, no plant-specific ASME Code stress report was written during the initial design. However, these components were originally designed to meet the intent of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with addenda through the Winter 1971. The structural integrity of the reactor internals design has been ensured by analyses performed on both generic and DCPP-specific bases.

Analysis

The qualification of the reactor vessel internals was first performed by Westinghouse on a generic basis for 40 years of operation. Some DCPP internal components were subsequently analyzed on a DCPP-specific basis.

T_{avg} Operating Range Reactor Vessel Internals Analysis

In support of the modification to the T_{avg} operating range, all of the core support structures, except for the upper core plate, lower core plate, and baffle bolts, were qualified based on analyzing the most limiting internal components [Reference 23]. From the four-loop generic stress report, for the applicable components, the most highly stressed due to cyclic thermal loads are:

1. Lower support plate
2. Lower support columns
3. Core barrel nozzles

These components therefore have the highest fatigue usage factors and were used to demonstrate compliance of the DCPP reactor internals with the intent of ASME Code, Section III, Subsection NG. The remaining internal components within the scope of the DCPP-specific analysis are bounded by the results of the limiting components and have sufficient margin in the stress and fatigue usage factors to accommodate any expected increases in stress range or number of cycles.

The enhanced DCPP Fatigue Management Program will monitor the 50-year design basis number of transients used in the T_{avg} operating range analysis to ensure it will remain valid for the period of extended operation.

Upper Core Plates

The Unit 2 upper core plate (UCP) was analyzed to support the 2005 Unit 2 upflow conversion modification [Reference 24]. The numbers of transients used in the analysis are bound by the numbers of transients in the current 50-year design basis.

The results of the four-loop generic stress report qualify the Unit 1 UCP for 40 years of operation. However, the results of the DCPP-specific analysis performed for the Unit 2 UCP can be applied to the Unit 1 component, since these components are of similar design [Reference 19].

The enhanced DCPP Fatigue Management Program will monitor the 50-year design basis number of transients used in the Unit 2 upflow conversion modification for the Unit 1 and 2 UCPs to ensure it will remain valid for the period of extended operation.

Lower Core Plates

The Unit 1 lower core plate (LCP) was analyzed for the increase in heat generation seen by the lower core plate due to power uprate [Reference 25]. The numbers of transients used in the analysis are bound by the numbers of transients in the current 50-year design basis. The results of the four-loop generic stress report qualify the Unit 2 LCP for 40 years of operation. However, the results of the DCPP-specific analysis performed for the Unit 1 LCP can be applied to the Unit 2 component, since these components are of similar design [Reference 19].

The enhanced DCPP Fatigue Management Program will monitor the 50-year design basis number of transients used in the Unit 1 power uprate for the Unit 1 and 2 LCPs to ensure it will remain valid for the period of extended operation.

Baffle-Former Bolts

The fatigue usage factor of the baffle-former bolts was originally shown to be less than 1.0 based on evaluation of test data which demonstrated acceptable performance for a set of bolt displacements. The adequacy of baffle-former bolts is an industry issue and their extended operation is addressed by ~~participation in industry level initiatives as described below~~*the PWR Vessel Internals program, which is summarized in Section B2.1.41*.

Flow Induced Vibration in the Reactor Vessel Internals

FSAR Section 3.9.1 and the original SER for DCPP discuss the design and vibration test programs for the reactor vessel internals performed as part of preoperational and startup testing. The dynamic behavior of reactor internals has been studied using experimental data obtained from prototype plants along with results of model tests and static and dynamic tests. Indian Point Nuclear Generating Unit 2 was the prototype for the DCPP Unit 1 internals verification program. Trojan Nuclear Plant data provide additional internals verification for Unit 2 (Unit 1 lower internals are similar to Indian Point Unit 2; Unit 2 lower internals are similar to Trojan). The tests indicated that no unexpected large vibration amplitudes existed in the internal structure during operation.

The licensing basis does not describe any time limited effects for a licensed operating period associated with flow-induced vibration. Therefore there are no TLAAs, in accordance with 10 CFR 54.3(a) Criteria 2 and 3.

~~*Participation in Industry Programs for Reactor Vessel Internals*~~
~~PG&E will (1) participate in industry programs for investigating and managing the aging effects on the reactor vessel internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; (3) upon completion of these programs, but not less than 24 months prior to entering the period of extended operation, PG&E will submit an inspection plan to the NRC for review and approval; and (4) in accordance with RIS 2011-07, PG&E will submit Information requested in the safety evaluation for MRP-227 "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," dated June 22, 2011 to the NRC for review and approval no later than 2 years after issuance of the renewed license or no later than 2 years before the plant enters PEO, whichever comes first.~~

Disposition: Aging Management, 10 CFR 54.21€(1)(iii)

The design basis number of transients will be managed for the period of extended operation by the DCPP Metal Fatigue of Reactor Coolant Pressure Boundary program, which is summarized in Sections 4.3.1 and B3.1. Action limits will permit completion of corrective actions before the design basis number of events is exceeded. The continued implementation provides reasonable assurance that fatigue in the reactor vessel internals will be managed for the period of extended operation in accordance with 10 CFR 54.21 €(1)(iii).

The integrity of the *reactor vessel internals and* baffle and former bolts will be managed by the ~~Reactor~~*PWR* Vessel Internals ~~Aging Management~~ program, which ~~DCPP committed to implement~~*is summarized* in ~~LRA Table A4-1, Commitment 22~~*Section B2.1.41*. The implementation of the *PWR Vessel Internals* program provides assurance that fatigue in the *reactor vessel internals and* baffle and former bolts will be managed for the period of extended operation in accordance with 10 CFR 54.21 €(1)(iii).

B1.5 AGING MANAGEMENT PROGRAMS

- *PWR Vessel Internals (Section B2.1.41)*

B2 AGING MANAGEMENT PROGRAMS

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	PLANT PROGRAM	EXISTING OR NEW	APPENDIX B REFERENCE
XI.M16	PWR Vessel Internals	~~Not Credited~~*PWR Vessel Internals*	~~N/A~~*new*	~~N/A~~*B2.1.41*

B2.1.41 PWR Vessel Internals

Program Description

The PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report (TR) No. EPRI 1022863, "Materials Reliability Program: Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," (MRP-227-A) and EPRI TR-1016609, "Materials Reliability Program: Inspection Standard for PWR Internals," (MRP-228) to manage the aging effects on the reactor vessel internal components. The recommended activities in MRP-227-A and additional plant-specific activities not defined in MRP-227-A are implemented in accordance with Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues." Plant procedures align with the augmented inspection and evaluation (I&E) criteria for PWR reactor vessel internals components specified in NRC Safety Evaluation (SE), Revision 1, on MRP-227.

The PWR Vessel Internals program is used to manage: (a) cracking, including stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclical loading; (b) loss of material induced by wear; (c) loss of fracture toughness due to either thermal aging, neutron irradiation embrittlement, or void swelling; (d) dimensional changes due to void swelling or distortion; and loss of preload due to thermal and irradiation-enhanced stress relaxation or irradiation-enhanced creep.

The DCPP PWR Vessel Internals program applies the guidance in MRP-227-A for inspecting, evaluating, and, if applicable, dispositioning non-conforming reactor vessel internals components at the facility. These examinations provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the period of extended operation. The program includes expanding periodic examinations *and other inspections, if the extent of the degradation identified exceeds the expected levels.*

The DCPP PWR Vessel Internals program uses MRP-227-A guidance for selecting reactor vessel internals components for inclusion in the inspection sample is based on a four-step ranking process. Through this process, the DCPP reactor vessel internals were assigned to one of the following four groups: "Primary," "Expansion," "Existing Programs," and "No Additional Measures."

The result of the four-step sample selection process is a set of "Primary" internals component locations that are inspected because they are expected to show the leading indications of the degradation effects, with another set of "Expansion" internals component locations that are specified to expand the sample should the indications be more severe than anticipated.

The degradation effects in a third set of internals locations are deemed to be adequately managed by "Existing Programs," such as American Society of Mechanical Engineers (ASME) Code, Section XI, Examination Category B-N-3, examinations of core support structures. A fourth set of internals locations are deemed to require "No Additional Measures."

Element 1 – Scope of Program

The DCPP PWR Vessel Internals Program provides guidelines to adequately manage the aging effects of selected DCPP reactor vessel internals components, both non-bolted and bolted. The DCPP reactor vessel internals consist of three basic assemblies: (1) the upper core support structure that is removed during each refueling operation to obtain access to the reactor core, (2) the lower core support structure that can be removed, if desired, following a complete core off-load, and (3) the incore instrumentation support structures.

The scope does not include fuel assemblies, control rod drive assemblies, nuclear instrumentation, bottom mounted instrumentation flux thimble tubes, and attachments welded to the reactor vessel. Fuel assemblies are periodically replaced (i.e., short lived), and therefore, are not subject to aging management review. Control rod drive assemblies are active components and therefore, are not subject to aging management review. Nuclear Instrumentation (i.e., incore neutron flux detectors) are active electrical components, and therefore, are not subject to aging management review. Bottom mounted instrumentation flux thimble tubes are managed by the Flux Thimble Tube Inspection program (B2.1.21). Welded attachments to the reactor vessel interior are subject to examination in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) and are therefore excluded from the scope of this program.

The DCPP PWR Vessel Internals program will be focused on managing age related degradation mechanisms by performing inspections intended to identify crack initiation and growth due to irradiation-assisted stress corrosion cracking and cracking due to fatigue/cyclical loading, loss of material induced by wear, primary water stress corrosion cracking, and stress corrosion cracking; reduction of fracture toughness due to irradiation embrittlement, thermal embrittlement, and void swelling; changes in dimensions due to void swelling; and loss of preload due to thermal and irradiation-enhanced stress relaxation or irradiation-enhanced creep, in reactor vessel internals components.

The DCPP PWR Vessel Internals program applies the guidance in MRP-227-A, which identifies and provides the basis for required augmented inspections, inspection techniques to permit detection and characterization of aging effects of interest, prescribed frequency of inspections, and examination acceptance criteria for assuring the functional integrity of Westinghouse reactor vessel internals. The program scope includes the Westinghouse plants "Primary" components listed in Table 4-3 of MRP-227-A and Westinghouse plants "Expansion" components listed in Table 4-6 of MRP-227-A. The aging effects of a third set of reactor vessel internals locations, consistent with those listed in Table 4-9 of MRP-227-A, are adequately managed by the existing DCPP programs. Those reactor vessel internals components for which the effects of all aging mechanisms were determined by MRP-227-A to be below the screening criteria were placed in the "No Additional Measures" group. No additional aging management is necessary for the reactor vessel internals components in the No Additional Measures group. In no case does the No Additional Measures determination supersede the ASME Section XI Inservice Inspection requirements for components in this group.

<u>Element 2 – Preventive Measures</u>

The DCPP PWR Vessel Internals program does not prevent degradation due to aging effects; rather, it provides measures for monitoring to detect the degradation prior to loss of intended function. Preventive measures to mitigate aging effects such as loss of material and cracking in the primary water system are established and implemented in accordance with the DCPP Water Chemistry program (B2.1.2), as described in GALL AMP XI.M2, Water Chemistry.

<u>Element 3 – Parameters Monitored or Inspected</u>

The DCPP PWR Vessel Internals program monitors the following aging effects by inspection, in accordance with the guidance of MRP-227-A or ASME Code Section XI, Category B-N-3:

(1) Cracking

Cracking is due to stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation assisted stress corrosion cracking (IASCC), or fatigue /cyclical loading. Cracking is monitored with a visual inspection for evidence of surface-breaking linear discontinuities or a volumetric examination. Surface examinations may also be used to supplement visual examinations for detection and sizing of surface-breaking discontinuities.

(2) Loss of Material

Loss of material is due to wear. Loss of material is monitored with a visual inspection for gross or abnormal surface conditions.

(3) Loss of Fracture Toughness

Loss of fracture toughness is due to thermal aging embrittlement (TE) or neutron irradiation embrittlement (IE). The impact of loss of fracture toughness on component integrity is indirectly managed by monitoring for cracking by using visual or volumetric examination techniques and by applying applicable reduced fracture toughness properties in flaw evaluations if any detected cracking is determined to be extensive enough to necessitate a supplemental flaw growth or flaw tolerance evaluation.

(4) Changes in Dimension

Changes in dimension are due to void swelling or distortion. The program supplements visual inspection with physical measurements to monitor for any dimensional changes due to void swelling or distortion.

(5) Loss of Preload

Loss of preload is due to thermal and irradiation-enhanced stress relaxation (ISR) or irradiation-enhanced creep. Loss of preload is monitored with a visual inspection for gross surface conditions that may be indicative of loosening in applicable bolted, fastened, keyed, or pinned connections.

The DCPP PWR Vessel Internals program manages the aging effects noted above consistent with the guidance designated for the Westinghouse-designed Primary components included in Table 4-3 of MRP-227-A and the Westinghouse-designed Expansion components included in Table 4-6 of MRP-227-A.

Element 4 – Detection of Aging Effects

The DCPP PWR Vessel Internals program detects the aging effects listed in Element 3 through performance of examinations of the parameters specified in MRP-227-A, Table 4-3 for Westinghouse-designed Primary components and for parameters specified in MRP-227-A, Table 4-6 for Westinghouse-designed Expansion components.

The DCPP PWR Vessel Internals program provides both examination acceptance criteria (See Element 6) for conditions detected during inspection of Westinghouse-designed Primary components, as well as criteria that are applied to determine if scope expansion of examinations is required. When the examination acceptance criteria for the Westinghouse designed Primary components included in MRP-227-A, Table 4-3 are not met, the program requires expanding the scope of examinations to include the additional Westinghouse-designed Expansion components included in MRP-227-A, Table 4-6.

MRP-227-A also identifies Existing Program components whose aging is managed through implementation of other programs. The DCPP PWR Vessel Internals program manages these Westinghouse designed components included in MRP-227-A, Table 4-9 through implementation of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B2.1.1) and the Flux Thimble Tube Inspection program (B2.1.22).

MRP-227-A includes a fourth group of components designated as requiring No Additional Measures. The aging of these components was determined to be negligible relative to other reactor internals, and therefore the program does not include any measures to monitor for effects of aging degradation in these components.

The inspections of the DCPP PWR Vessel Internals program are conducted as recommended in MRP-227-A. The program standards for examination methods, procedure content, and personnel qualifications are consistent with the requirements specified in MRP-228.

Volumetric (UT) and visual (VT-3, EVT-1) examinations are used for detecting aging effects including general conditions, surface breaking discontinuities, and cracking caused by SCC, IASCC, and fatigue.

VT-3 examinations are applied to detection of cracking only when the flaw tolerance of the component or affected assembly, as evaluated for reduced fracture toughness, has been shown to be tolerant of easily detectable large flaws, even under reduced fracture toughness conditions. VT-3 examinations may also be used to inspect for loss of material that is induced by wear, and other aging effects such as gross distortion caused by void swelling and irradiation growth, and aging effects of loss of preload that is caused by thermal and irradiation-enhanced stress relaxation and creep.

Surface measurements may be used to supplement visual examinations required by this program to reject or accept relevant indications.

The impact of loss of fracture toughness (due to TE or IE) on component integrity is indirectly managed by monitoring for cracking using visual or volumetric examination techniques and by applying applicable reduced fracture toughness properties in the flaw evaluations after cracking is determined to be extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

One hundred percent of the accessible volume/area of each component will be examined for the Primary and Expansion components inspection category components. The minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total (accessible plus inaccessible) inspection area/volume be examined. When addressing a set of like components (e.g. bolting), the minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total population of like components (accessible plus inaccessible).

If conditions are detected during the examination, DCPP will enter the information into the corrective action program and evaluate whether the results of the examination ensure that the component (or set of components) will continue to meet the intended function under all licensing basis conditions of operation until the next scheduled examination. Engineering evaluations that demonstrate the acceptability of a detected condition will be performed consistent with WCAP-17096-NP.

Element 5 – Monitoring and Trending

The methods for monitoring, recording, evaluating, and trending the data that result from the DCPP PWR Vessel Internals program's inspections are in accordance with the evaluation methodologies detailed in MRP-227-A, Section 6. This includes the recommended evaluation methodologies for flaw depth sizing and crack growth determinations as well as for performing applicable limit load, linear elastic and elastic-plastic fracture analyses of relevant flaw indications.

The DCPP PWR Vessel Internals program applies applicable fracture toughness properties, including reductions for thermal aging or neutron embrittlement, in the flaw evaluations of the components in cases where cracking is detected in a reactor vessel internals component and is extensive enough to warrant a supplemental flaw growth or flaw tolerance evaluation.

In accordance with MRP-227-A, the DCPP PWR Vessel Internals program includes criteria to evaluate the aging effects in the inaccessible portions of the components and the resulting impact on the intended function(s) of the components. For redundant components, the program includes criteria to evaluate the aging effects in the *population of components that are inaccessible to the applicable inspection technique and the resulting impact on the intended function(s) of the assembly containing the components.*

Examination and re-examinations are implemented in accordance with MRP-227-A, together with the criteria specified in MRP-228 for inspection methodologies, inspection procedures, and inspection personnel, provide timely detection, reporting, and corrective actions with respect to the effects of age related degradation mechanisms within the scope of the program.

<u>Element 6 – Acceptance Criteria</u>

The DCPP PWR Vessel Internals program acceptance criteria for the Westinghouse-designed Primary and Expansion component examinations are consistent with MRP-227-A, Section 5A. For the Westinghouse-designed Expansion components, ASME Code, Section XI, Section IWB-3500 acceptance criteria apply. The DCPP PWR Vessel Internals program establishes acceptance criteria for any physical measurement monitoring methods that are credited for aging management of particular reactor vessel internals components.

<u>Element 7 – Corrective Actions</u>

Any detected conditions that do not satisfy the examination acceptance criteria are required to be dispositioned through the DCPP corrective action program. The disposition will ensure that licensing and design basis functions of the reactor internals will continue to be fulfilled.

The following corrective actions are suggested for the disposition of detected conditions that exceed the examination acceptance criteria:

(a) Supplemental examinations to further characterize and potentially dispose of a detected condition;

(b) Engineering evaluation that demonstrates the acceptability of a detected condition;

(c) Repair, in order to restore a component with a detected condition to acceptable status; or

(d) Replacement of a component with an unacceptable detected condition

If an engineering evaluation is used to disposition an examination result that does not meet the examination acceptance criteria, the engineering evaluation shall be conducted per an NRC-approved evaluation methodology.

DCPP quality assurance (QA) procedures and review and approval processes are implemented in accordance with the requirements of 10 CFR 50 Appendix B and include: administrative controls as described in DCPP FSAR Section 17.2 and provisions that specify when follow-up actions are required to be taken to verify that corrective actions are effective and those implemented to address significant conditions adverse to quality are effective in preventing recurrence of the condition.

Element 8 – Confirmation Process

DCPP QA procedures and review and approval processes are implemented in accordance with the requirements of 10 CFR 50 Appendix B and include: administrative controls as described in DCPP FSAR Section 17.2 and provisions that specify when follow-up actions are required to be taken to verify that corrective actions are effective and those implemented to address significant conditions adverse to quality are effective in preventing recurrence of the condition.

The implementation of the guidance in MRP-227-A, in conjunction with the requirements of NEI 03-08 and other guidance documents, reports, or methodologies referenced in this AMP, provides an acceptable level of quality and an acceptable basis for confirming the quality of inspection, flaw evaluation, and other elements of aging management of the DCPP PWR Vessel Internals.

Element 9- Administrative Controls

See Element 8.

Element 10 – Operating Experience

The systematic and ongoing review and assessment of relevant DCPP-specific and industry operating experience for its impact to the program are governed by Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues," and MRP-227-A, Appendix A.

Based on industry operating experience, DCPP proactively replaced the originally installed Alloy X-750 guide tube support pins (split pins) with strain hardened (cold worked) 316 stainless steel pins in 1999 for Unit 1 and 2006 for Unit 2 to reduce the susceptibility for stress corrosion cracking in the support pins.

Relatively few incidents of PWR internals aging degradation have been reported in operating U.S. commercial PWR plants, and a summary of observations is maintained in Appendix A of MRP-227-A. With exception of the ASME Section Inservice Inspection portions, the DCPP PWR Vessel Internals program will be a new program. A key element of the program defined in MRP-227-A is the requirement for utilities to continue to report aging effects of PWR vessel internal components identified during *examination. DCPP, through its participation in PWR Owners Group and EPRI-MRP activities, will continue to benefit from the reporting of examination information and results, and will share its own operating experience with the industry through those groups.*

NUREG-1801 Consistency

The PWR Vessel Internals program is a new program that, when implemented, will be consistent with the recommendations of XI.M16A, "PWR Vessel Internals," specified in NUREG-1801, Revision 2, and LR-ISG-2011-04.

Exceptions to NUREG-1801

None

Enhancements

None

Conclusion

The implementation of the PWR Vessel Internals 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.

LR-ISG-2011-05, "Ongoing Review of Operating Experience"

LR-ISG-2011-05 was issued by the NRC Staff to establish a framework for the consideration of operating experience concerning aging management and age-related degradation during the term of a renewed operating license. It also clarifies the NRC Staff's acceptance criteria and review procedures with respect to the ongoing review of operating experience.

PG&E's licensing basis for the review of applicable industry and plant-specific operating experience is documented LRA Table A4-1, Item 20. Reference PG&E Letter DCL-09-079, dated November 23, 2009. PG&E committed to perform an ongoing review of industry and applicable plant-specific operating experience throughout the PEO pertaining to the following AMPs:

(1) Steam Generator Tube Integrity (B2.1.8)
(2) One-Time Inspection (B2.1.16)
(3) Selective Leaching of Materials (B2.1.17)
(4) Buried Piping and Tanks Inspection (B2.1.18)
(5) External Surfaces Monitoring (B2.1.20)
(6) Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)
(7) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.14)
(8) Fuse Holders (B2.1.34). This program was deleted in PG&E Letter DCL-13-119, dated December 23, 2013.
(9) Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.35)
(10) Metal Enclosed Bus (B2.1.36)

The license renewal SER evaluated LRA Table A4-1, Item 20 as documented in SER Appendix A, Item Number 20.

In order to address the recommendations in LR-ISG-2011-05, PG&E updates its licensing basis as shown in LRA Section A1 and Table A4-1, Item 20. Upon receipt of the renewed operating licenses, ongoing reviews of operating experience will apply to all DCPP AMPs following the process described in LRA Section A1.

Refer to markups of LRA Section A1 and Table A4-1, Item 20, in Attachment 15.

LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms"

LR-ISG-2012-01 contains recommendations to address wall thinning due to erosion mechanisms such as cavitation, flashing, droplet impingement, and solid particle impingement. Changes have been made to the GALL Report and the SRP for review of LRAs.

PG&E's licensing basis for the DCPP FAC program is documented in PG&E Letter DCL-09-079, dated November 23, 2009.

The NRC evaluated the DCPP FAC program in its SER, Section 3.0.3.2.2, dated June 2, 2011.

In order to address the recommendations in LR-ISG-2012-01, PG&E updates its licensing basis for the FAC program as follows:

(1) The expanded definition of "wall thinning" including erosion mechanisms such as cavitation, flashing, droplet impingement, and solid particle impingement will be incorporated into the DCPP FAC program, LRA Section A1.6.

(2) The ISG-revised definition of "flow-accelerated corrosion" currently aligns with the DCPP FAC program. The DCPP FAC program will be updated to reflect the specific forms of erosion described in the ISG.

(3) PG&E will include the ISG-recommended activities to monitor wall thinning due to erosion mechanisms by updating the DCPP FAC program to:

  (a) Identify susceptible locations based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry operating experience.

  (b) Periodically verify the effectiveness of corrective actions for which design changes have been implemented to eliminate the source of the erosion mechanism. Periodic wall thickness measurements will be taken until the effectiveness of the corrective actions has been confirmed.

  (c) Review periodic wall thickness measurements as the basis to ensure functionality during the PEO will be maintained.

  (d) Remove the term "high-energy" from the scope of the DCPP FAC program.

(e) Align with the changes outlined in LR-ISG-2012-01, Appendix D, "Mark-up Showing Changes to the GALL Report."

(4) The ISG revised SRP-LR and GALL Report Tables aging management review items to align with the changes made to the scope of GALL Report AMP XI.M17.

Refer to revised LRA Tables 3.2.2-1, 3.2.2-3, 3.3.2-3, 3.3.2-8, 3.4.2-3, and 3.4.2-5 in this Attachment.

Refer to revised LRA Section A1.6 in Attachment 15. Section A1.6 also revises NSAC-202L from Revision 3 to Revision 4 as described in Attachment 13.

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
Class 1 Piping < 4in	*PB*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 5*
Orifice	*PB, TH*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 5*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 5*
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 5*
Valve	*LBS, PB, SIA*	*Stainless Steel Cast Austenitic*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 5*

Plant Specific Notes:

5. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item V.D.E-407 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

Table 3.2.2-3 Engineered Safety Features – Summary of Aging Management Evaluation – Residual Heat Removal System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	*PB, TH*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 6*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 6*
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 6*
Valve	*PB*	*Stainless Steel Cast Austenitic*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 6*

Plant Specific Notes:

6. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item V.D.E-407 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

Table 3.3.2-3 Auxiliary Systems – Summary of Aging Management Evaluation – Saltwater and Chlorination System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	*LBS*	*Carbon Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Orifice	*LBS*	*Stainless Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Piping	*LBS, PB*	*Carbon Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Piping	*LBS*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Piping	*LBS, PB*	*Copper Alloy*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Piping	*LBS*	*Nickel Alloys*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB*	*Carbon Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB*	*Copper Alloy*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*PB*	*Copper Alloy (Aluminum > 8%)*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB*	*Nickel Alloys*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*
Valve	*LBS, PB, SIA*	*Stainless Steel Cast Austenitic*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*

Table 3.3.2-3 Auxiliary Systems – Summary of Aging Management Evaluation – Saltwater and Chlorination System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	*PB*	*Titanium*	*Raw Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 3*

Plant Specific Notes:

3. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item VII.C1.A-409 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

Table 3.3.2-8 Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	*LBS, PB, SIA, TH*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 10*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 10*
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 10*
Valve	*LBS, PB, SIA*	*Stainless Steel Cast Austenitic*	*Treated Borated Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 10*

Plant Specific Notes:

10. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item VII.E1.A-407 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

Table 3.4.2-3 Steam and Power Conversion System – Summary of Aging Management Evaluation – Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	*LBS*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Piping	*LBS, PB, SIA*	*Carbon Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Piping	*LBS*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Valve	*LBS, PB, SIA*	*Carbon Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Valve	*LBS, PB*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*

Plant Specific Notes:

2. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item VIII.D1.S-408 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

Table 3.4.2-5 Steam and Power Conversion System – Summary of Aging Management Evaluation – Auxiliary Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Orifice	*LBS, PB, SIA, TH*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Piping	*LBS, PB, SIA*	*Carbon Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Valve	*LBS, PB, SIA*	*Carbon Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Secondary Water (Int)*	*Wall thinning due to erosion*	*Flow-Accelerated Corrosion (B2.1.6)*	*None*	*None*	*H, 2*

Plant Specific Notes:

2. *Program provisions for wall thinning due to erosion apply. Refer to LR-ISG-2012-01, Appendix B, Line Item VIII.D1.S-408 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.*

LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"

Section A, Recurring Internal Corrosion

LR-ISG-2012-02, Section A, provides recommendations to augment existing AMPs to address RIC.

Following the changes discussed below, DCPP will be consistent with the recommendations in LR-ISG-2012-02, Section A.

LR-ISG-2012-02, Section A, revised the SRP for engineered safety features systems, auxiliary systems, and steam and power conversion systems to require a review of the plant's CAP to identify RIC. Consistent with the methodology outlined in LR-ISG-2012-02, Section A, PG&E conducted a review of the past ten years of DCPP OE to identify internal corrosion events that are consistent with the definition of RIC in LR-ISG-2012-02. Based on this review, PG&E has identified RIC in the following systems:

(1) Makeup Water System (System 16)

(2) Saltwater and Chlorination (System 17)
  (a) Saltwater (System 17A)
  (b) Auxiliary Saltwater (System 17B)
  (c) Chlorination (System 17C)

(3) Fire Protection (System 18)

(4) Oily Water and Turbine Sump System (System 27)

Makeup Water System (System 16)

During a search of DCPP OE from November 23, 2009, to September 30, 2014, PG&E identified internal corrosion of copper components exposed to potable water in the DCPP makeup water system. Consistent with LR-ISG-2012-02, Section A, the internal corrosion is considered RIC because of the frequency of occurrence and significance of aging effect. The internal surfaces of copper makeup water system components exposed to potable water are managed by the DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. Consistent with LR-ISG-2012-02, Appendix G, 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. Copper components exposed to potable water in the makeup water system that are currently in-scope for 10 CFR 54.4 (a)(2) may be re-evaluated to potentially further refine the scope of 10 CFR 54.4 (a)(2).

Saltwater and Chlorination (System 17)

In the original OE search performed and documented in the LRA (PG&E Letter DCL-09-079), PG&E identified microbiologically-induced corrosion in its ASW system, for which aging management is performed by the OCCW System program. Consistent with LR-ISG-2012-02, Section A, this is considered RIC because of the frequency of occurrence and significance of aging effect. This aging effect has been managed with the OCCW System program by continuous chlorination and periodic system inspections to verify effectiveness of continuous chlorination, as documented in PG&E Letter DCL-09-079, LRA Section B2.1.9, and SER Section 3.0.3.1.7.

To ensure effectiveness, the OCCW System program performs visual examinations of the ASW system piping every fourth refueling outage to inspect the integrity of the plastic pipe liner and detect indications of corrosion of the base piping material. The examinations look for visible lining holes, lining cracks, or any loss of the internal lining that would expose the piping base material. If the acceptance criteria for the internal lining are not met, a corrective action document is written to repair the internal lining and piping if necessary, and an engineering evaluation is completed to determine the effect of the piping corrosion on system operability. Some of the piping in the ASW system is located below ground; these visual inspections are conducted remotely with robot inspection devices equipped with video cameras.

The heat removal capability of heat exchangers in the CCW system is also currently tested prior to each refueling outage to ensure that it is greater than or equal to 100 percent of its design basis, through the testing of heat transfer effectiveness and flow testing. Test results are documented, trended, and validated for heat removal capabilities. If the results of the testing indicate any parameter outside of established acceptance criteria, deficiencies are resolved via DCPP's CAP.

SER Section 3.0.3.1.7 concluded that, based on the operating experience, the OCCW System program can adequately manage the detrimental effects of aging on SSCs within the scope of the program and implementation of the program has resulted in the applicant taking corrective actions.

Fire Protection System (System 18)

PG&E has identified RIC in portions of the fire protection system that contain carbon steel components exposed to raw water. The DCPP Fire Water System program will be enhanced as described in LRA Section B2.1.13 (PG&E Letter DCL-09-079, dated November 23, 2009), PG&E Letter DCL-10-057, dated June 3, 2010, and PG&E Letter

DCL-10-101, dated August 17, 2010 (RAI Responses B2.1.13-2, B2.1.13-3), and SER Section 3.0.3.2.6 to perform additional volumetric examinations and visual inspections of above-ground fire water system piping. The DCPP Fire Water System program will also be revised to address the changes to GALL Report AMP XI.M27 made by LR-ISG-2012-02, Section C, as discussed in Enclosure 1, Attachment 7C of this letter. The revisions that are sufficient to manage RIC identified in the fire protection system are summarized below:

(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.

DCPP's acceptance criteria for inspections of fire water piping are:

(1) ability of the fire protection system to maintain required pressure and flow rates,

(2) minimum design wall thickness is maintained,

(3) no fouling exists in the sprinkler system that could cause corrosion in the sprinkler heads.

<u>Oily Water and Turbine Sump System (System 27)</u>

During a search of DCPP OE from November 23, 2009, to September 30, 2014, PG&E identified internal corrosion of stainless steel components exposed to raw water in the DCPP oily water and turbine sump system. Consistent with LR-ISG-2012-02, Section A, the internal corrosion is considered RIC because of the frequency of occurrence and significance of aging effect. However, these components are located in an out-of-scope portion of the oily water and turbine sump system, in a raw water environment considerably more harsh than that seen by in-scope components. This portion of the system is located in the turbine building sump, where the raw water environment has the potential to include seawater, caustics, and acids. The in-scope portions of the oily water and turbine sump system are constructed of carbon steel, carbon steel (galvanized), cast iron (gray cast iron), and copper, and are located in the 12-kV cable spreading rooms, the component cooling water heat exchanger rooms, and the diesel generator rooms within the turbine building. The raw water that the in-scope piping is exposed to consists of groundwater or used potable water, and is only used intermittently. Because RIC has only occurred in a material/environment combination that is separate from the in-scope portions of the oily water and turbine sump system, no actions to manage RIC are required.

LRA Sections 3.3.2.1.5 and 3.3.2.1.12, and Tables 3.3.2-5 and 3.3.2-12 are revised to incorporate loss of material due to recurring internal corrosion as an aging effect in the fire protection system.

The NRC Staff also revised the criteria for the use of GALL Report AMP XI.M38 to emphasize that the program should not be used to manage RIC. Consistent with LR-ISG-2012-02, Section A, the DCPP Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program will state that an aging effect is considered as RIC if it has occurred over three or more sequential or nonsequential cycles for a ten-year OE search of aging effects with the same aging mechanism and for which the aging effect resulted in the component not meeting plant-specific acceptance criteria, or experiencing a reduction in wall thickness greater than 50 percent regardless of the minimum wall thickness. If the criteria for RIC are met, use of the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program is allowed if augmented requirements are included to adequately manage the aging. Refer to revised LRA Section A1.22 in Attachment 15.

3.3.2.1.5 Makeup Water System

Aging Effects Requiring Management

The following makeup water system aging effects require management:

- *Loss of material from recurring internal corrosion*

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
Flow Element	*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, 6*
Heater	*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, 6*
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, 6*
Tank	*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, 6*
Trap	*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, 6*
Valve	*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, 6*

Notes for Table 3.3.2-5:

Plant Specific Notes:

6 *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22) is used to manage recurring internal corrosion in the makeup water system. Reference LR-ISG-2012-02, Section A, and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7A.*

3.3.2.1.12 Fire Protection System

Aging Effects Requiring Management

The following fire protection system aging effects require management:

- *Loss of material from recurring internal corrosion*

Table 3.3.2-12 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bellows	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Flow Element	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Flow Indicator	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Hose Station	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Hydrant	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Piping	*LBS, PB, SS*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Piping	*PB*	*Carbon Steel (Galvanized)*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Piping	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Pump	*PB, SS*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*

Table 3.3.2-12 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Strainer	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Strainer	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Tank	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Test Connection	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Valve	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*
Valve	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Loss of material; recurring internal corrosion*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 5*

Notes for Table 3.3.2-12:

Plant Specific Notes:

5 The Fire Water System program (B2.1.13) is used to monitor for recurring internal corrosion in the Fire Protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-400 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7A.

LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"

Section B, "Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38, 'Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components'"

LR-ISG-2012-02, Section B, contains recommended inspection sample sizes, population, and frequency for GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."

PG&E's licensing basis for the DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-073, dated July 7, 2010
(3) PG&E Letter DCL-10-105, dated August 18, 2010
(4) PG&E Letter DCL-10-147, dated November 24, 2010

The NRC evaluated the DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program in its SER, Section 3.0.3.2.11, dated June 2, 2011.

In order to address the recommendations in LR-ISG-2012-02, Section B, PG&E updates its licensing basis for the Inspection of Internal Surfaces program as follows.

(1) The DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will inspect 20 percent of each population of in-scope components with the same material, environment, and aging effect, with a maximum sample size of 25 components, in each 10-year period during the PEO.

(2) Where practical, the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program will select inspection locations from bounding or lead components (e.g., low or stagnant flow) most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin.

(3) The minimum sample size specified above does not override the opportunistic inspection basis of the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program. Opportunistic inspections will still be conducted, even though the sample size specified above may have already been inspected in a ten-year period.

(4) Inspections conducted on a component in a more severe environment may be credited as an inspection in a less severe similar environment for the same material and aging effect. Alternatively, similar environments for the same material can be combined into a larger group as long as the inspections occur on components located in the more severe environment.

(5) LRA Table A4-1, Item 9, is revised to reflect the updated implementation schedule for the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program, as described in LR-ISG-2012-02, Appendix B, Table 3.0-1.

LRA Section A1.22 and Table A4-1, Item 9, are revised to address LR-ISG-2012-02, Section B. Refer to Attachment 15.

LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"

Section C, "Flow Blockage of Water-Based Fire Protection System Piping, GALL Report AMP XI.M27, 'Fire Water System'"

PG&E's licensing basis for the DCPP Fire Water System, XI.M27 program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-057, dated June 3, 2010
(3) PG&E Letter DCL-10-101, dated August 17, 2010
(4) PG&E Letter DCL-10-128, dated October 12, 2010
(5) PG&E Letter DCL-10-134, dated October 27, 2010

The NRC Staff evaluated the DCPP Fire Water System program in its SER, Section 3.0.3.2.6, dated June 2, 2011.

In order to address the recommendations in LR-ISG-2012-02, Section C, PG&E updates its licensing basis for the Fire Water System program as follows.

Based on the recommendations in LR-ISG-2012-02, Section C, PG&E will inspect and test in-scope fire water system components within the scope of license renewal consistent with guidance of LR-ISG-2012-02, Section C and the NFPA-25 (2011 Edition) sections listed in LR-ISG-2012-02, Appendix D, Table 4a, with the following exceptions:

(1) NFPA-25, Section 5.2.1.1 specifies inspecting sprinklers from the floor annually.

<u>Exception</u>
PG&E inspects sprinklers outside containment from the floor every 18 months as required by ECG 18.4. By NRC letter dated January 13, 1993, "Issuance of Amendments for Diablo Canyon Nuclear Power Plant, Unit Nos. 1 and 2 (License Amendments 75 and 74, respectively) the NRC approved DCPP's request to relocate the fire protection Technical Specifications and associated bases to the ECGs. Therefore, DCPP testing frequencies are in compliance with the licensing basis previously approved by NRC.

<u>Basis</u>
An 18-month inspection frequency reduces exposure of personnel to safety considerations such as those raised by continuous process operations, and radiological dose, and does not exceed the plant refueling outage interval.

The majority of sprinkler systems are located in areas that are frequented by plant personnel during operator rounds and other work activities. These activities have identified sprinkler system degradation such as leaks, mechanical damage, obstruction of sprinkler spray patterns, and loose pipe hangers. Upon discovery, these issues are entered into the CAP for evaluation, increasing the likelihood that degradation will be identified outside of procedure-driven sprinkler system inspections. A review of plant operating experience since 1997 has not revealed age-related degradation occurring at such a rate that would warrant increasing the procedure-driven sprinkler system visual inspection from 18 months to annually.

Conclusion
PG&E will continue to inspect sprinklers outside containment from the floor every 18 months.

(2) NFPA-25, Section 6.3.1.1 specifies that flow tests will be conducted every five years at the hydraulically most remote hose connection of each zone of an automatic standpipe system. NFPA-25, Section 6.3.1.5 specifies that a test shall be performed on all standpipe systems with automatic water supplies in accordance with the requirements of Chapter 13. NFPA-25, Section 13.2.5 specifies the test of the automatic water supply shall be performed annually at each water based fire protection system riser.

Exception
Instead of flow testing each zone of an automatic standpipe system and testing the automatic water supply on each riser of the fire water system annually, PG&E will rely on redundant water supplies and system pressurization sources as described in the DCPP FSAR Update, Section 9.5.1.2.1, and the following tests to ensure adequate flow capability:

(a) flow testing three hose station locations where flow test results bound other locations in the system,
(b) flow testing fire main supply lead-ins to each building at least every 18 months,
(c) hose station functional testing, and
(d) water supply valve position verification

Basis
Flow testing of automatic standpipe systems increases risk due to the potential for water contacting critical equipment in the area. In addition, flow in the radiologically-controlled areas increases the amount of liquid radwaste. NFPA-25 specifies that flow testing is performed to verify the fire water supply still provides the design pressure at the required flow. Similarly, NFPA-25 indicates the primary purpose of the Section 13.2.5 test is to identify major

reductions in water flow due to significant obstructions to flow such as a failed or mispositioned valve. The DCPP Fire Water System program will rely on the following activities to demonstrate unobstructed flow of the automatic standpipe system at design pressure and verify the fire main supply to each building is unobstructed.

The DCPP fire water system is normally supplied through the yard fire water loop, which is supplied and gravity-pressurized by the RWSR. There are two fire water supply lead-ins from the fire water loop to the auxiliary building (which includes the fuel handling building), and four to the turbine building. A seismically qualified water system within the turbine building, auxiliary building, and containment structures provides uninterrupted water supply to hose stations servicing safety related areas of the plant. The qualified system consists of the FWST, two electric pumps, fire mains, and piping. The system is designed to provide redundant flow paths, with the ability to align any of six water supply lead-ins to the hose station or sprinkler systems inside the auxiliary building, turbine building and containment structures. Two fire water pumps in the fuel handling portion of the auxiliary building will auto-start on low fire water system pressure, drawing water from the FWST to pressurize the system within the auxiliary and turbine buildings, and the containment structures. Check valves on the mains into these buildings from the yard loop ensure that system pressure developed by the fire pumps is not lost due to backflow to the yard loop.

Every five years, PG&E will flow test at least three remote firewater hose station locations in accordance with NFPA-25, Section 6.3.1, to demonstrate the standpipe system can supply design pressure at required flow.

The intake structure fire water is supplied by a branch line off of the yard loop. Adequate pressure is ensured, as hose station connections in the intake are 300 feet below the minimum RWSR level. The availability of adequate flow to the intake structure automatic standpipe system and sprinklers is verified by flow testing the hydrant just outside of the intake structure in accordance with NFPA-25, Section 7.3.2. During the flow test, the static and residual pressure are recorded and trended. In addition, all of the hose stations within the scope of license renewal are functionally tested at least every three years. Functional testing consists of verifying: (a) the hose station valve is functional, (b) there is flow through the valve and connection, and (c) the absence of any indication of obstruction or other undue restriction of water flow.

NFPA-25, Section 13.2.5 testing is prescribed to identify major reductions in waterflow to the fire water system that can be caused by obstructions such as mispositioned valves. PG&E verifies that valves that are normally open in the fire water system are not mispositioned by sealing them open and, with the exception of those in containment, by walkdown every 31 days. The isolation valves in containment are verified open during operational testing of containment hose station connections every refueling outage.

NFPA-25, Section 13.2.5 states that a test shall be conducted annually at each fire protection system riser to determine if there has been a change in the condition of the water supply. Appendix A of NFPA-25, Section A13.2.5, clarifies that "The test for standpipe system should be done at the low-point drain for each standpipe or the main drain test connection where the supply main enters the building." PG&E will perform a flow test of all the fire water supply mains that enter the auxiliary building, turbine building, and the radwaste storage facility every 18 months to verify the design is being maintained. If there is a ten percent reduction in full flow pressure when compared to previously performed tests, the deficiency will be entered into the CAP.

The auxiliary building and the intake structure have combined standpipe and sprinkler systems such that the flow testing of the automatic standpipe verifies the supply to the sprinkler systems is unobstructed. Every 18 months, the absence of blockage in sprinkler branch lines and the associated supply mains is demonstrated during fire water flow alarm testing by opening a flushing connection or drain valve at the end of branch lines.

Conclusion

(a) PG&E will enhance the Fire Water System program to flow test at least three firewater hose station locations in accordance with NFPA-25, Section 6.3.1 to demonstrate the system is capable of providing design pressure at required flow.

(b) PG&E will continue to flow test the fire hydrant outside the intake structure in accordance with NFPA-25, Section 7.3.2, and record the static and residual pressures during the test and trend the results.

(c) PG&E will continue the functional test of all the hose stations within the scope of license renewal at least every three years.

(d) PG&E will continue to seal open valves that are normally open in the fire water system and verify they are not mispositioned, with the exception of those in containment, by a walkdown every 31 days.

(e) PG&E will continue to open a flushing connection or drain valve at the end of sprinkler branch lines every 18 months.

(f) PG&E will enhance the Fire Water System program to perform a flow test of the fire water supply mains that enter the auxiliary building, turbine building, and radwaste storage facility every 18 months to verify the design is being maintained. If there is a ten percent reduction in full flow pressure when compared to previously performed tests, the deficiency will be entered into the CAP.

(3) NFPA-25, Section 9.2.5.5 specifies performing an annual inspection of the exterior surface of fire water tanks.

Exception
A diver will inspect the external surface of the FWST every five years.

Basis
Typically, the inspection of the exterior surface of a fire water tank is conducted via walkdown and visual inspection of the tank. The DCPP FWST is inside of the transfer tank and is coated with vinyl paint for corrosion protection. The transfer tank contains makeup water. A diver will inspect the internal surface of the transfer tank and the internal and external surfaces of the FWST every five years. The five year inspection interval is consistent with the frequency requirement in NFPA-25, Section 9.2.6.1.2, for the internal inspection of tanks with corrosion protection.

Conclusion
PG&E will enhance the DCPP Fire Water System program to inspect the internal and external surface of the FWST by diver every five years.

(4) NFPA-25, Section 13.4.3.2.2 specifies annually trip testing each deluge valve system at full flow, incorporating full functionality of the system including automatic detection.

Exception
PG&E performs a combination of trip testing of the outdoor deluge systems at full flow and reduced flow, and verifies water supply to the system is available, but does not include automatic detection. The hydrogen seal oil cooler deluge system is trip tested at minimal flow and will be tested with air, smoke, or other medium.

Basis
Automatic actuation of the DCPP deluge systems is provided by pilot lines. Utilizing automatic detection of the deluge system through actuation of one of the pilot line sprinklers requires replacement of the pilot line sprinkler head. Actuation of the deluge system is with a manual pull box that depressurizes the pilot system causing the deluge valve to open without requiring replacement of a pilot sprinkler.

The deluge system nozzles are visually inspected every 18 months to verify the spray patterns are unobstructed and the nozzle openings are not blocked.

Opening the deluge valve and allowing water flow out of the sprinkler nozzles in critical equipment areas is considered a risk significant activity. The deluge systems that protect electric transformers are trip tested at full flow every three years and annually at a reduced flow through a system drain. The reduced flow test ensures the deluge valves are operational while avoiding the risks associated with spraying water on the transformers. Every 18 months, the deluge system strainer flush valves are fully opened, the flow is observed verifying sufficient flow is available to the system, that there is no blockage, and the static and residual pressures are recorded.

The only other deluge system within the scope of license renewal is for the hydrogen seal oil cooler. Actuation of the hydrogen seal oil cooler deluge valves is performed every 18 months at minimal flow through a system drain, to prevent water from flowing to the spray nozzles. Dry piping downstream of the deluge valve will be flow tested with air, smoke, or other medium to ensure the piping and nozzles are clear every second visual inspection of the spray nozzles (i.e., every three years). Past visual inspections have found the hydrogen seal oil cooler deluge system to be clean and free of corrosion. The benefit of the nozzle testing at shorter intervals is negated by the risk of introducing foreign material while breaking open and closing the spray piping to perform the test.

<u>Conclusion</u>

(a) PG&E will continue to visually inspect the deluge system nozzles every 18 months to verify the spray patterns are unobstructed and the nozzle openings are not blocked.

(b) PG&E will continue to trip test the outdoor deluge systems at full flow every three years and at reduced flow annually.

(c) PG&E will continue to flush the outdoor deluge systems every 18 months by fully opening strainer flush valves. Flow will be observed during the test to verify that sufficient flow is available to the system, that there is no blockage, and the static and residual pressures are recorded.

(d) PG&E will continue to actuate the hydrogen seal oil cooler deluge valves every 18 months at minimal flow through a system drain to prevent water from flowing to the spray nozzles.

(e) PG&E will enhance the Fire Water System program to flow test dry piping downstream of the hydrogen seal oil cooler deluge valve with air, smoke, or other medium to ensure the piping and nozzles are clear every second visual inspection (i.e., every three years) of the spray nozzles.

(5) Steel tanks will be inspected in accordance with NFPA-25, Section 9.2.6. An exception is being taken to Section 9.2.6.4 in that any degradation, such as described in LR-ISG-2012-02, Appendix D, Table 4a, Note 4, will be entered into the CAP and an engineering evaluation of the inspection results will be performed to determine whether further actions are required. Follow-up actions will be in accordance with either NFPA-25 Section 9.2.7 or 4.6.

(6) NFPA-25 sections referenced in this Attachment specify frequencies. An exception is being taken regarding inspection periodicity in that, in accordance with NFPA-25, Section 4.6, subject to the authority having jurisdiction, frequencies may be adjusted based on testing and inspection results.

Further Enhancements to be Consistent with LR-ISG-2012-02, Section C

PG&E will also make the following enhancements to the DCPP Fire Water System program. Following these enhancements, and with the exceptions stated above, the DCPP Fire Water System program will be consistent with LR-ISG-2012-02, Section C.

(1) Consistent with NFPA-25, Section 5.2.1.1, PG&E will include the acceptance criteria for sprinkler visual inspection.

(2) Consistent with LR-ISG-2012-02, Appendix D, Table 4a, Note 5, PG&E will inspect sprinklers inside containment every refueling cycle for each Unit.

(3) Consistent with LR-ISG-2012-02, Appendix D, Table 4a, Note 1, for those NFPA-25 sections referenced in this Attachment, the inspection scope and periodicity will be consistent with the 2011 Edition, with the exception listed in (6) above.

(4) PG&E will flow test fire water supply piping in the yard and hydrants consistent with NFPA-25, Sections 7.3.1 and 7.3.2.

(5) PG&E will inspect the FWSTs internally, consistent with NFPA-25, Section 9.2.6, with the exception to Section 9.2.6.4 listed above.

(6) PG&E will inspect, repair, and replace strainers every five years consistent with NFPA-25, Sections 10.2.1.7 and 10.2.7.1.

(7) Consistent with NFPA-25, Section 10.3.4.3.2, PG&E will clean deluge system nozzles and retest the system when obstructions are identified during flow testing.

(8) Consistent with LR-ISG-2012-02, Section C.iii.d, PG&E will identify any portions of the fire water deluge system piping that are normally dry and periodically subject to flow, but are unable to be drained. During the five year period prior to the PEO, PG&E will perform either: (a) a flow test or flush sufficient to detect potential flow blockage, or (b) an inspection of 100 percent of the internal surface on those portions unable to be drained. Every 5 years thereafter, 20 percent of the portion will be volumetrically tested so that after 25 years, 100 percent has been volumetrically tested. If and when the hydrogen seal oil cooler deluge system spray piping becomes wetted, an inspection will be conducted to determine if any portions of the spray piping cannot be drained or allows water to collect, and the flow testing and inspection criteria for normally dry wet sprinkler systems above will be applied.

(9) Consistent with NFPA-25 Section 14.2, PG&E will internally inspect wet sprinkler systems using a method capable of detecting flow blockage due to fouling in addition to loss of material.

(10) PG&E will perform obstruction investigations as required by and consistent with NFPA Section 14.3.

(11) 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.

(12) Consistent with LR-ISG-2012-02, Section C.iii.c, following detection of irregularities identified during visual inspections that could indicate wall loss below nominal wall thickness, follow-up volumetric examination will be performed.

(13) Consistent with LR-ISG-2012-02, Section C.iii.p, DCPP Fire Water System program references to biofouling will be revised to the general term fouling.

LRA Sections 3.3.2.1.12 and 3.3.2.2.10.6 and LRA Tables 3.3.1 and 3.3.2-12 are revised to address LR-ISG-2012-02, Section C, as shown in this Attachment. LRA Section A1.13 and Table A4-1, Item 3 are revised to address LR-ISG-2012-02, Section C, as shown in Attachment 15.

3.3.2.1.12 Fire Protection System

Aging Effects Requiring Management

The following fire protection system aging effects require management:

- Loss of material
- Loss of material, cracking and changes in material properties
- Loss of preload
- *Flow blockage due to fouling*

3.3.2.2.10.6 Copper alloy piping and components exposed to internal condensation

The Fire Water System AMP (B2.1.13) manages loss of material due to general pitting, and crevice corrosion for fire water system copper alloy internal surfaces exposed to internal condensation and moisture.

~~The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22) manages loss of material from pitting and crevice corrosion for copper alloy internal surfaces exposed to internal condensation and moisture.~~

Table 3.3.1 Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems (Continued)

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1.28	Copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal)	Loss of material due to pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes	Consistent with NUREG-1801. The plant-specific aging management program(s) used to manage the aging include: *Fire Water System (B2.1.13)*~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22).~~ See further evaluation in Section 3.3.2.2.10.6.

Table 3.3.2-12 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bellows	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Flow Element	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Flow Element	*PB*	*Stainless Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 7*
Flow Indicator	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Hose Station	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Hydrant	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Hydrant	*PB*	*Ductile Iron*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Orifice	*PB*	*Stainless Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 7*
Piping	*LBS, PB, SS*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Piping	*PB*	*Carbon Steel (Galvanized)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Piping	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Piping	*PB*	*Ductile Iron*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Piping	*PB*	*Carbon Steel*	*Atmosphere/ Weather (Int)*	*Loss of material*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 9*
Piping	*PB*	*Carbon Steel*	*Plant Indoor Air (Int)*	*Loss of material*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 9*
Piping	*PB*	*Carbon Steel*	*Atmosphere/ Weather (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 9*

Table 3.3.2-12 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	*PB*	*Carbon Steel*	*Plant Indoor Air (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 9*
Piping	*LBS, PB*	*Stainless Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 7*
Pump	*PB, SS*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Pump	PB, SS	Aluminum	Plant Indoor Air (Int)	None	None	V.F-2	3.2.1.50	A, 2
Spray Nozzle	*SP*	*Copper Alloy*	*Atmosphere/ Weather (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 11*
Spray Nozzle	*SP*	*Copper Alloy*	*Atmosphere/ Weather (Ext)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 11*
Spray Nozzle	*SP*	*Copper Alloy*	*Plant Indoor Air (Ext)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 11*
Spray Nozzle	*SP*	*Copper Alloy*	*Plant Indoor Air (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 11*
Strainer	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Strainer	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Strainer	*PB*	*Copper Alloy*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 8*
Tank	*PB*	*Carbon Steel*	*Raw Water (Ext)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 10*
Tank	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 10*
Test Connection	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Tubing	*LBS, PB*	*Stainless Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 7*

Table 3.3.2-12 Auxiliary Systems – Summary of Aging Management Evaluation – Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	*PB*	*Carbon Steel*	*Plant Indoor Air (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 12*
Valve	*PB*	*Carbon Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Valve	*PB*	*Cast Iron (Gray Cast Iron)*	*Plant Indoor Air (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 12*
Valve	*PB*	*Cast Iron (Gray Cast Iron)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Valve	PB	Copper Alloy	Plant Indoor Air (Int)	Loss of material	*Fire Water System (B2.1.13)*~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~	VII.G-9	3.3.1.28	E, *5*
Valve	*LBS, PB*	*Copper Alloy*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 8*
Valve	*PB*	*Copper Alloy (> 15% Zinc)*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 8*
Valve	*PB*	*Ductile Iron*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Valve	*PB*	*Stainless Steel*	*Raw Water (Int)*	*Flow blockage*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 7*

Plant Specific Notes:

2 This line represents priming pumps associated with the portable diesel driven fire pumps that are not normally connected to the fire water system when the pumps are stored. *The aging effect of flow blockage from LR-ISG 2012-02, Appendix C, Item VII.G.A-403 is not applicable because this line is not normally connected to the Fire Water system so there is no upstream corrosion products that may accumulate in this pump. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

5 *The Fire Water System program (B2.1.13) is used to monitor copper alloy piping, piping components and piping elements exposed to condensation (internal) for loss of material in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-143 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

6 *The Fire Water System program (B2.1.13) is used to monitor steel piping, piping components, and piping elements exposed to raw water for fouling that leads to corrosion and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-33 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

7 *The Fire Water System program (B2.1.13) is used to monitor stainless steel piping, piping components, and piping elements exposed to raw water for fouling that leads to corrosion, and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-55 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

8 *The Fire Water System program (B2.1.13) is used to monitor copper alloy piping, piping components and piping elements exposed to raw water for fouling that leads to corrosion, and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-197 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

9 *The Fire Water System program (B2.1.13) is used to monitor steel piping, piping components, and piping elements exposed to moist air or condensation (internal)for fouling that leads to corrosion and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-23 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

10 *The Fire Water System program (B2.1.13) is used to monitor steel tanks exposed to soil or concrete, air indoor uncontrolled, raw water, treated water, waste water, or condensation for fouling that leads to corrosion, and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-402 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

11 *The Fire Water System program (B2.1.13) is used to monitor copper alloy sprinklers exposed to air indoor controlled, air indoor uncontrolled, air outdoor, moist air, condensation, raw water, or treated water for flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-403 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

12 *The Fire Water System program (B2.1.13) is used to monitor steel, stainless steel, copper alloy or aluminum fire water system piping, piping components, and piping elements exposed to air indoor uncontrolled (internal), air outdoor (internal), or condensation (internal) for fouling that leads to corrosion, and flow blockage due to fouling in the fire protection system. Reference LR-ISG-2012-02, Appendix C, Line VII.G.A-404 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*

LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"

Section D, "Revisions to the Scope and Inspection Recommendations of Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.M29, 'Aboveground Metallic Tanks'"

LR-ISG-2012-02, Section D, provides scope and inspection recommendations for AMP XI.M29, "Aboveground Metallic Tanks." PG&E did not credit the Aboveground Metallic Tanks AMP during the preparation of DCPP LRA. The aging of in-scope aboveground metallic tanks is managed by the Water Chemistry program (B2.1.2), One Time Inspection program (B2.1.16), Close Cycle Cooling Water program (B2.1.9), Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program (B2.1.22) and the External Surfaces Monitoring Program (B2.1.20).

PG&E's licensing basis for the DCPP Water Chemistry program is documented in PG&E Letter DCL-09-079, dated November 23, 2009.

PG&E's licensing basis for the DCPP One-Time Inspection program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-073, dated July 7, 2010
(3) PG&E Letter DCL-10-134, dated October 27, 2010
(4) PG&E Letter DCL-13-119, dated December 23, 2013

PG&E's licensing basis for the DCPP Open-Cycle Cooling Water System program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-122, dated September 22, 2010
(3) PG&E Letter DCL-10-151, dated November 24, 2010

PG&E's licensing basis for the DCPP Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-073, dated July 7, 2010
(3) PG&E Letter DCL-10-105, dated August 18, 2010
(4) PG&E Letter DCL-10-147, dated November 24, 2010

PG&E's licensing basis for the DCPP External Surfaces Monitoring program is documented in the following letters:

(1) PG&E Letter DCL-09-079, dated November 23, 2009
(2) PG&E Letter DCL-10-130, dated October 12, 2010

The NRC evaluated the DCPP Water Chemistry, One-Time Inspection, Open-Cycle Cooling Water, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and External Surfaces Monitoring programs in its SER, Sections 3.0.3.1.2, 3.0.3.1.10, 3.0.3.1.7, 3.0.3.2.11, and 3.0.3.2.10, respectively, dated June 2, 2011.

LR-ISG-2012-02, Section D, revised XI.M29, Program Element 1, "Scope of Program," to include indoor large-volume tanks that meet all of the following criteria: (a) have a large volume (i.e., greater than 100,000 gallons); (b) are designed to near-atmospheric internal pressures; (c) sit on concrete; and (d) are exposed internally to water. DCPP does not have any indoor large-volume tanks that meet these criteria.

DCPP has the following outdoor tanks in the scope of license renewal:

(1) Refueling water storage tanks (LRA Table 3.2.2-1 Safety Injection System)
(2) Component cooling water surge tanks, (LRA Table 3.3.2-4 Component Cooling Water System)
(3) Condensate storage tanks, (LRA Table 3.3.2-5 Makeup Water System)
(4) Transfer storage tank, (LRA Table 3.3.2-5 Makeup Water System)
(5) Backup air supply accumulator tanks, (LRA Table 3.3.2-7 Compressed Air System)
(6) Steam generator blowdown tanks, (LRA Table 3.4.2-1 Turbine Steam Supply System)

Following the enhancements described below, DCPP will be consistent with the recommendations provided in LR-ISG-2012-02, Section D.

The RWSTs are stainless steel tanks encased in concrete. These tanks sit on concrete foundations with an internal environment of treated water and plant indoor air. The AMR lines for these tanks are shown on LRA Table 3.2.2-1. The internal surfaces of these tanks exposed to treated water are managed by the Water Chemistry program (B2.1.2) and the One Time Inspection program (B2.1.16). The internal surfaces of these tanks exposed to plant indoor air are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22). The exterior surfaces of these tanks are encased in concrete and are not exposed to condensation; therefore, there are no aging effects that require managing. To address the recommendations in LR-ISG-2012-02, Section D, a new AMR line to perform volumetric examinations of the tank bottom from the inside has been added to LRA Table 3.2.2-1. The volumetric examinations will be performed from inside the tank each ten-year period starting ten years before entering the PEO to confirm the absence of loss of material due to corrosion. These volumetric examinations will be performed using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22).

The CCW surge tanks are carbon steel tanks with an internal environment of closed cycle cooling water and dry gas. These tanks are not exposed to soil or concrete. The AMR lines for these tanks are shown on LRA Table 3.3.2-4. The internal surfaces of these tanks are managed by the Closed Cycle Cooling Water program (B2.1.10). The external surfaces of these tanks are managed by the External Surfaces Monitoring program (B2.1.20). The external surfaces will be visually inspected every refueling outage interval by the External Surfaces Monitoring program (B2.1.20). No revisions to the AMR lines are required to address the recommendation from LR-ISG-2012-02, Section D.

The condensate storage tanks and the transfer storage tank are carbon steel tanks encased in concrete. These tanks sit on a concrete foundation with an internal environment of demineralized water and plant indoor air. The AMR lines for these tanks are shown on LRA Table 3.2.2-5. The internal surfaces exposed to demineralized water are managed by the Water Chemistry program (B2.1.2) and One Time Inspection program (B2.1.16). The internal surfaces exposed to plant indoor air are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22). The exterior surfaces of these tanks are encased in concrete and are not exposed to condensation; therefore, there are no aging effects that require managing. To address the recommendation from LR-ISG-2012-02 Section D a new AMR line to perform volumetric examinations of the tank bottom from the inside is added to LRA Table 3.2.2-5. The volumetric examinations will be performed from inside the tank each ten-year period starting ten years before entering the PEO to confirm the absence of loss of material due to corrosion. These volumetric examinations will be performed using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.22).

The backup air supply accumulator tanks are carbon steel tanks with an internal environment of dry gas. These tanks are not exposed to soil or concrete. The AMR lines for these tanks are shown on LRA Table 3.3.2-7. Since the internal surface of these tanks is exposed to dry gas there are no aging effects that require managing. The external surfaces of these tanks are managed by the External Surfaces Monitoring program (B2.1.20). The external surfaces will be visually inspected every refueling outage interval by the External Surfaces Monitoring program (B2.1.20). No revisions to the AMR lines are required to address the recommendation from LR-ISG-2012-02, Section D.

The steam generator blowdown tanks are insulated carbon steel tanks with an internal environment of secondary water. These tanks are not exposed to soil or concrete. The AMR lines for these tanks are shown on LRA Table 3.4.2-1, with the external environment listed as Plant Indoor Air. The external environment of these tanks is Atmosphere/Weather, and is revised in Attachment 9. The internal surfaces exposed to secondary water are managed by the Water Chemistry program (B2.1.2) and One Time Inspection program (B2.1.16). The external surfaces beneath insulation will be visually inspected every refueling outage interval by the External Surfaces Monitoring program (B2.1.20), in accordance with the recommendations of LR-ISG-2012-02, Section E. No revisions to the AMR lines are required to address the recommendations from LR-ISG-2012-02, Section D.

LRA Sections 3.2.2.1.1 and 3.3.2.1.5, and Tables 3.2.2-1, 3.3.2-5, and A4-1, Item 9, are revised as shown in this Attachment to address the changes in LR-ISG-2012-02, Section D recommendations. LRA Sections A1.22 and Table A4-1, Item 9, are revised as shown in Attachment 15.

3.2.2.1.1 Safety Injection System

Environment

The safety injection system components are exposed to the following environments:

- Borated Water Leakage
- Closed-Cycle Cooling Water
- *Concrete*
- Demineralized Water
- Dry Gas
- Encased in Concrete
- Lubricating Oil
- Plant Indoor Air
- Reactor Coolant
- Treated Borated Water
- Ventilation Atmosphere

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, 5*

G Environment not in NUREG-1801 for this component and material.

5. 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.

3.3.2.1.5 Makeup Water System

Environment

The makeup water system components are exposed to the following environments:

- Atmosphere/ Weather
- Buried
- *Concrete*
- Demineralized Water
- Encased in Concrete
- Lubricating Oil
- Plant Indoor Air
- Potable Water
- Raw Water
- Sodium Hydroxide
- Sulfuric Acid

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, 6*

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.