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

Section E, "Corrosion Under Insulation"

LR-ISG-2012-02, Section E, provides recommendations to inspect the external surfaces underneath insulation to address loss of material and cracking that could remain undetected. PG&E did not credit the Aboveground Metallic Tanks AMP during the preparation of DCPP's LRA, and instead manages the aging of the external surfaces of aboveground metallic tanks with the External Surfaces Monitoring program (B2.1.20). Aging of the external surfaces of insulated aboveground metallic tanks will be managed under the External Surfaces Monitoring Program (B2.1.20).

PG&E 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 Staff evaluated the DCPP External Surfaces Monitoring program in its SER, Section 3.0.3.2.10, dated June 2, 2011.

PG&E updates its licensing basis for the External Surfaces Monitoring program as follows to address the recommendations in LR-ISG-2012-02, Section E.

(1) Periodic inspections of external surfaces underneath insulation will be conducted during each ten-year period during the PEO.

(2) The following inspection will be performed for outdoor in-scope insulated components, except tanks, and all indoor insulated components exposed to condensation (because the in-scope component is being operated below the dew point):

    (a) Remove insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type.

    (b) Remove insulation and inspect 20 percent of the surface area of components with configurations that do not conform to a 1-foot axial length determination (e.g., valves, accumulators).

    (c) Alternatively, remove the insulation and inspect any combination of a minimum of 25 1-foot axial length sections and components for each material type.

(d) Inspect each material type and environment (e.g., air-outdoor, moist air) where condensation or moisture on the surfaces of the component could occur routinely or seasonally.

(3) The following inspections will be performed for in-scope indoor insulated tanks exposed to condensation, because the in-scope component is being operated below the dew point, or in-scope outdoor insulated tanks:

(a) Inspect the tank exterior after removing either 25 1-square-foot sections or 20 percent of the tank's surface area.

(b) Sample inspection points will be distributed in such a way that inspections will occur on the tank dome and sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water might collect, such as on top of stiffening rings.

(4) Inspection locations will be based on the likelihood of corrosion under insulation occurring (e.g., alternate wetting and drying in environments in which trace contaminants could be present, length of time the system operates below the dew point). Subsequent inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation when the following conditions are met based on the results of the initial inspection:

(a) No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.

(b) No evidence of stress corrosion cracking.

(c) If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as conducted for the initial inspection.

(5) For tightly adhering insulation that is impermeable to moisture:

(a) Removal of insulation is not required unless there is evidence of damage to the moisture barrier.

(b) Tightly adhering insulation will be considered to be a separate population from the remainder of insulation installed on in-scope components.

(c) The entire population of in-scope components that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

LRA Sections 3.2.2.1.4, 3.3.2.1.9, 3.4.2.1.5, and Tables 3.2.2-4, 3.3.2-4, 3.3.2-9, 3.3.2-10, 3.3.2-11, 3.3.2-18, 3.4.2-1, 3.4.2-3, and 3.4.2-5 are revised to address the changes made by LR-ISG-2012-02, Section E, as shown in this Attachment. LRA Section A1.20 and Table A4-1, Item 8, are revised as shown in Attachment 15.

3.2.2.1.4 Containment HVAC System

Aging Effects Requiring Management

The following containment HVAC system aging effects require management:

- *Cracking*
- Hardening and loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Table 3.2.2-4 Engineered Safety Features – Summary of Aging Management Evaluation – Containment HVAC System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, PB, SIA, SS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F3-2	3.3.1.56	D, *10*
Piping	LBS, PB, SIA, SS	Stainless Steel	Plant Indoor Air (Ext)	~~None~~*Loss of material*	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	~~VII.J-15~~ *None*	~~3.3.1.94~~ *None*	~~A~~*H, 12*
Piping	*LBS, PB, SIA, SS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 11*
Valve	PB, SIA, SS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F3-2	3.3.1.56	D, *10*
Valve	PB, SIA, SS	Stainless Steel	Plant Indoor Air (Ext)	~~None~~*Loss of material*	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	~~VII.J-15~~ *None*	~~3.3.1.94~~ *None*	~~A~~*H, 12*
Valve	*PB, SIA, SS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 11*

10. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

11. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line V.E.E-406 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

12. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line V.E.E-403 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

3.3.2.1.9 Miscellaneous HVAC Systems

Aging Effects Requiring Management

The following miscellaneous HVAC systems aging effects require management:

- *Cracking*
- Hardening and loss of strength
- Loss of material
- Loss of preload

Table 3.3.2-4 Auxiliary Systems – Summary of Aging Management Evaluation – Component Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, *6*
Piping	LBS, PB, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-9	3.3.1.58	B, *6*
Piping	PB	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*~~VII.J-15~~	*None*~~3.3.1.94~~	*H, 7*~~A~~
Piping	*PB*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 7*
Piping	PB	Stainless Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	None	None	G, *7*
Piping	*PB*	*Stainless Steel*	*Atmosphere/ Weather (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 7*
Tank	PB	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-9	3.3.1.58	B, *6*
Valve	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, *6*
Valve	PB	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-9	3.3.1.58	B, *6*
Valve	PB	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*~~VII.J-15~~	*None*~~3.3.1.94~~	*H, 7*~~A~~

Table 3.3.2-4 Auxiliary Systems – Summary of Aging Management Evaluation – Component Cooling Water 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*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 7*

6. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*
7. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VII.C1.A-405 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*

Table 3.3.2-9 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous HVAC Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	PB, SS	Copper Alloy	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F4-12	3.3.1.25	E, *4*
Valve	SIA, SS	Copper Alloy	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*	*None*	~~C~~*H, 5*
Valve	PB, SIA, SS	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*	*None*	~~A~~*H, 5*
Valve	*PB, SIA, SS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 5*

4. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

5. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VII.I.A-405 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

Table 3.3.2-10 Auxiliary Systems – Summary of Aging Management Evaluation – Control Room HVAC System

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 (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-11	3.3.1.58	B, *9*
Piping	PB	Carbon Steel (Galvanized)	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*~~VII.J-6~~	*None*~~3.3.1.92~~	~~A~~*H*, 2, *10*
Piping	PB	Copper Alloy	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.F1-16	3.3.1.25	E, *9*

9. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

10. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VII.F1.A-405 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-9	3.3.1.58	B, 7
Piping	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, 7
Piping	LBS	Copper Alloy	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.I-2	3.4.1.41	A, 7
Valve	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, 7
Valve	LBS, PB, SIA	Copper Alloy	Plant Indoor Air (Ext)	*Loss of material*~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	~~VIII.I-2~~ *None*	~~3.4.1.41~~ *None*	~~A~~*H, 8*

7. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

8. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VII.F2.A-405 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-9	3.3.1.58	B, *7*
Piping	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, *7*
Piping	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*
Piping	LBS	Copper Alloy	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-2~~	*None* ~~3.4.1.41~~	*H, 8* ~~A~~
Piping	LBS, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VII.J-15~~	*None* ~~3.3.1.94~~	*H, 8* ~~A~~
Piping	*LBS, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Piping	LBS	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 8* ~~A~~
Piping	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Tank	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tank	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Loss of material*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Tank	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Valve	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VII.I-8	3.3.1.58	B, *7*
Valve	LBS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*
Valve	LBS, SIA	Copper Alloy	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-2~~	*None* ~~3.4.1.41~~	*H, 8* ~~A~~
Valve	LBS	Copper Alloy (> 15% Zinc)	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-2~~	*None* ~~3.4.1.41~~	*H, 8* ~~A~~
Valve	*LBS*	*Copper Alloy (> 15% Zinc)*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Valve	LBS, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VII.J-15~~	*None* ~~3.3.1.94~~	*H, 8* ~~A~~
Valve	*LBS, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 8* ~~A~~
Valve	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*

7. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*
8. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VII.I.A-405 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*

3.4.2.1.5 Auxiliary Feedwater System

Aging Effects Requiring Management

The following auxiliary feedwater system aging effects require management:

- *Cracking*
- Loss of material
- Loss of preload
- Reduction of heat transfer

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	LBS, PB, SIA, SS	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B, *7*
Piping	LBS, PB, SIA, SS	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*
Piping	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	~~A~~*H, 8*
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Tank	LBS, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*
Tank	SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	~~C~~*H, 8*
Tank	*SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*
Valve	LBS, PB, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B, *7*
Valve	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *7*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	LBS	Copper Alloy	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-2~~	*None* ~~3.4.1.41~~	*H, 8*~~A~~
Valve	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 8*~~A~~
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 8*

7. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*
8. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VIII.A.S-402 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*

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
Piping	PB, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B, *2*
Piping	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *2*
Piping	LBS	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 3* ~~A~~
Piping	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 3*
Valve	PB, SIA	Carbon Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-8	3.4.1.28	B, *2*
Valve	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *2*
Valve	PB	Stainless Steel	Atmosphere/ Weather (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	None	None	G, *3*
Valve	*PB*	*Stainless Steel*	*Atmosphere/ Weather (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*G, 3*
Valve	LBS, PB	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)*~~None~~	*None*~~VIII.I-10~~	*None*~~3.4.1.41~~	*H, 3*~~A~~
Valve	*LBS, PB*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 3*

2. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*
3. *External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VIII.D1.S-402 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*

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
Piping	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *2*
Piping	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 3* ~~A, 2~~
Piping	*LBS, PB, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 3*
Tank	LBS	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 3*~~A, 2~~
Tank	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 3*
Valve	LBS, PB, SIA	Carbon Steel	Plant Indoor Air (Ext)	Loss of material	External Surfaces Monitoring Program (B2.1.20)	VIII.H-7	3.4.1.28	B, *2*
Valve	LBS, PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	*Loss of material* ~~None~~	*External Surfaces Monitoring Program (B2.1.20)* ~~None~~	*None* ~~VIII.I-10~~	*None* ~~3.4.1.41~~	*H, 3*~~A~~
Valve	*LBS, PB, SIA*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*Cracking*	*External Surfaces Monitoring Program (B2.1.20)*	*None*	*None*	*H, 3*

2. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

3. External Surfaces Monitoring (B2.1.20) program provisions for outdoor insulated or for indoor insulated components that operate below the dew point apply. Reference LR-ISG-2012-02 Appendix C Line VIII.G.S-402 and PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.

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

Section F, "External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, 'Buried and Underground Piping and Tanks'"

LR-ISG-2012-02, Section F, provides recommendations for inspecting the internal surfaces of underground piping covered by AMP XI.M41, Buried and Underground Piping and Tanks, which were previously removed from the AMP by LR-ISG-2011-03.

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 Staff 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 F, PG&E updates its licensing basis for the Inspection of Internal Surfaces program as follows.

(1) The condition of internal surfaces of buried and underground components can be based on inspections of the interior surfaces of accessible components where the material, environment and aging effects of the buried or underground component are similar to those of the accessible component.

(2) If inspections of the interior surfaces of accessible components with material, environment, and aging effects similar to those of the interior surfaces of buried or underground components are not conducted, internal visual or external volumetric inspections capable of detecting loss of material on the internal surfaces of the buried or underground components will be conducted.

No changes to the LRA Section 3 tables are necessary to address LR-ISG-2012-02, Section F. LRA Section A1.22 and Table A4-1, Item 9, are revised to address LR-ISG-2012-02, Section F.

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

Section G, "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38"

LR-ISG-2012-02, Section G, removes the term "hydrotesting" from the program description for AMP XI.M38. The term is being removed because it is typically associated with test pressures well above the normal operating and design pressures.

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 Staff 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.

The term "hydrotesting" is not used in DCPP's Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program.

LR-ISG-2012-02, Section G, also clarifies the intent of the pressurization option. As recommended by LR-ISG-2012-02, Section G, PG&E revises the DCPP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (A1.22) to indicate that when the pressurization augmented technique is used, that the component is sufficiently pressurized to expand the surface of the material in such a way that cracks or crazing would be evident. LRA Section A1.22 and Table A4-1, Item 9, are revised to address LR-ISG-2012-02, Section G. Refer to Attachment 15.

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

Section H, "Key Miscellaneous Changes to the GALL Report and SRP-LR"

LR-ISG-2012-02, Section H, provides recommendations on key miscellaneous changes to the GALL Report, and the SRP for review of LRA.

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 Staff 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.

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

(1) The ISG revised the definition of "hardening and loss of strength" to provide a more complete list of aging effects and improve consistency with program Element 3, "Parameters Monitored/Inspected" of GALL Report AMP XI.M38, "Inspection of Internal Surfaces and Miscellaneous Piping and Ducting Components." LRA Section A1.22 is revised to be consistent with the revised definition of hardening and loss of strength in accordance with LR-ISG-2012-02, item H.i.

(2) The ISG revised the definition of "elastomer degradation" to include change in material properties as an aging effect example. This makes the definition more consistent with program Element 3, "Parameters Monitored/Inspected" of GALL Report AMP XI.M38, "Inspection of Internal Surfaces and Miscellaneous Piping and Ducting Components." LRA Section A1.22 is revised to be consistent with the revised definition of elastomer degradation in accordance with LR-ISG-2012-02, Item H.ii.

(3) The ISG revised program Element 1, "Scope of Program," of GALL Report AMP XI.M38, "Inspection of Internal Surfaces and Miscellaneous Piping and Ducting Components," to allow the aging of internal surfaces of metallic and polymeric components to be managed by inspections from the external surface when the material and environment combinations are

the same. PG&E's Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program will allow external inspections of components to be credited for managing: (a) loss of material from internal surfaces of metallic components and (b) loss of material, cracking, and change in material properties from the internal surfaces of polymeric components when this condition is met. LRA Section A1.22 is revised to allow external inspections to be credited if the internal material and environment conditions are similar in accordance with LR-ISG-2012-02, Item H.iii.

(4) The ISG revised the definition of fouling to incorporate discussions related to flow blockage of water-based fire protection system piping in LR-ISG-2012-02, Section C. The expanded definition of fouling does not impact the information in the DCPP LRA. Fouling due to flow blockage specific to the fire protection systems is addressed in LR-ISG-2012-02, Section C, "Flow Blockage of Water-Based Fire Protection System Piping," GALL Report AMP XI.M27, "Fire Water System."

(5) The SRP-LR and GALL Report were revised with the following:

(a) The ISG added an AMR line item for high-density polyethylene piping exposed to an underground environment. DCPP does not have any high-density polyethylene components in-scope for license renewal. No updates to the DCPP LRA are needed to address this change.

(b) The ISG added the waste water environment to Line Item 3.3.1-72 in SRP-LR Table 3.3-1, and Item VII.I.A-407 to the GALL Report to reduce the number of non-consistent items in an applicant's LRA. DCPP's LRA was written to GALL Revision 1, which does not include waste water as an environment. The GALL Revision 2 definition of waste water is captured by the GALL Revision 1 definition of raw water. The DCPP Selective Leaching program currently manages in-scope components exposed to raw water. Therefore, no updates to the DCPP LRA are needed to address this change.

(c) The ISG added aging management review lines for copper alloy, stainless steel, and steel components exposed to raw water (nonsafety-related components not covered by NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"), with aging management by GALL Report AMP XI.M38, "Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components." The only existing AMP for

copper alloy, stainless steel, and steel exposed to raw water prior to this change was GALL Report AMP XI.M20, "Open Cycle Cooling Water." The existing line items in DCPP's LRA aging management evaluation tables use g Generic Note E and a plant-specific note to show that aging is instead managed by the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program, which is consistent with LR-ISG-2012-02, Section H. Therefore, no updates to the DCPP LRA are needed to address this change. Use of the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program instead of the OCCW program was reviewed and approved by the NRC in the DCPP SER, dated June 2, 2011.

(d) The ISG added steel and stainless steel pump casings exposed to waste water being managed for loss of material due to general (steel only), pitting, crevice, and microbiologically influenced corrosion to GALL Report AMP XI.M36, "External Surfaces Monitoring", to allow the use of XI.M36 to manage internal aging effects. Although DCPP has pumps exposed internally to raw water, the only pump casings exposed to waste water or raw water (external) are managed by the OCCW System program. Therefore, no updates to the DCPP LRA are needed to address this change.

(e) The ISG added jacketed calcium silicate insulation, fiberglass insulation, and foamglas® insulation exposed to outdoor air and uncontrolled indoor air being managed with GALL Report AMP XI.M36 for degradation of thermal insulation due to moisture intrusion. The ISG also stated that walkdowns of jacketing installed on in-scope insulation would be an acceptable method of managing aging. Alternatively, an inspection methodology would need to be proposed by the applicant. DCPP has no insulation of this type in-scope for license renewal. Insulation associated with the safety injection system, containment spray system, auxiliary feedwater system, chemical and volume control system, and the residual heat removal system is not required to minimize heat load into rooms during design basis events. DCPP does not use insulation in the emergency diesel generator exhaust penetrations to maintain temperature of the structure. The pressurizer loop seals are insulated to maintain the loop seal water near saturation conditions so that, upon safety valve operation, most of the seal water flashes to steam, thus reducing the hydraulic loading on the downstream piping. However, by PG&E Letter DCL-10-123, RAI 3.1.2.3.2-2, the calcium silicate insulation on the pressurizer loop seals was

replaced with reflective mirror insulation. Therefore, no updates to the DCPP LRA are needed to address this change.

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

LR-ISG-2013-01, "Draft Interim Staff Guidance 2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings'"

The NRC issued the final LR-ISG-2013-01 on November 14, 2014. PG&E will evaluate LR-ISG-2013-01 and provide an updated evaluation to the NRC by February 2015.

In response to draft LR-ISG-2013-01, PG&E performed a review to identify the components with internal coatings that are within the scope of license renewal.

Based on this review, the in-scope components with internal coatings include:

(1) Condensate polisher demineralizer
(2) Zinc injection pump pulsation dampener
(3) CCW system heat exchanger waterboxes
(4) CCW butterfly valves
(5) Makeup water system asbestos cement pipe
(6) Condensate storage tank
(7) CST floating cover
(8) Raw water storage reservoir
(9) Transfer tank
(10) ASW piping and pipe components
(11) Circulating water pump equalizing lines
(12) Fire water system asbestos cement pipe
(13) Fire water storage tank
(14) Fire water system sprinkler piping with galvanized coating
(15) Demineralizer regenerant receiver tanks
(16) Demineralizer regenerant receiver tank piping
(17) Hot laundry and shower drain tanks
(18) Diesel fuel oil storage tank manway
(19) Centrifugal charging pump gear oil cooler shell
(20) Steam generator blowdown demineralizer regeneration system piping and pipe components

Item number (13): The fire water storage tank internal coating is not addressed in the response to this ISG. The aging effects associated with the fire water storage tank internal coatings are managed by the Fire Water System program as described in PG&E's evaluation of LR-ISG-2012-02 in Attachment 7C of this submittal.

Item numbers (15) and (16): The demineralizer regenerant receiver tanks are coated with a rubber liner and the associated demineralizer regenerant receiver tank piping has a plastic liner. The liners were designed to protect the tank from acid and caustic from demineralizer regeneration, but the system was never used for that purpose. Instead, the tanks and associated piping were converted to accept excess equipment floor drain

liquid. Degradation of the demineralizer regenerant receiver tank liners and associated piping liner cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for components in the scope of license renewal. Corrosion rates and inspection intervals are not based on the integrity of the liners. Applying the guidance of the draft LR-ISG-2013-01, the coatings in the demineralizer regenerant receiver tanks and the piping associated with the demineralizer regenerant receiver tanks, do not require inspections of coatings.

Item number (17): The interior of the hot laundry and shower drain tanks are coated with paint. Degradation of the tank coating cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for components in the scope of license renewal. Corrosion rates and inspection intervals are not based on the integrity of the coating. Applying the guidance of the draft LR-ISG-2013-01, the hot laundry and shower drain tanks coatings do not require inspections of coatings.

Item number (20): The steam generator blowdown treatment demineralizer system piping and piping components and demineralizers have internal coatings or linings. The flowpath of this system was evaluated and it was determined that failure of these coatings and linings could not adversely affect a safety-related function or prevent satisfactory accomplishment of any function identified under 10 CFR 54.4(a)(3) by causes such as reduction in flow, drop in pressure, or reduction in heat transfer for components in the scope of license renewal. Corrosion rates or inspection intervals are not based on the integrity of these coatings. Applying the guidance of the draft LR-ISG-2013-01, the steam generator blowdown treatment demineralizer system coatings do not require inspections of coatings.

For the remaining item numbers, coating inspections are required to manage loss of coating integrity. The inspections will be managed using the Closed Cycle Cooling Water System program, Open Cycle Cooling Water System program, Fire Water System program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. These programs will include the following elements for the management of internal Service Level III (augmented) coatings:

<u>Scope of Program</u>

The scope of program includes components manufactured from copper alloy, concrete, foam, nickel alloy, stainless steel, and steel with a Service Level III (augmented) internal coating exposed to closed cycle cooling water, fuel oil, lubricating oil, raw water, treated borated water, and demineralized water.

<u>Inspection Method and Parameters Inspected</u>

Visual inspections are intended to identify coatings that do not meet acceptance criteria, such as peeling and delamination. The definition of these terms is

included in Section 10.2 of ASTM D7167-12, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant." Physical testing is intended to identify potential delamination of the coating.

Inspection Scope

Baseline Service Level III (augmented) coatings inspections will be conducted in the ten-year period prior to the PEO. Subsequent inspections will be established by a coating specialist based on an evaluation (discussed in extent of inspections below). The inspection intervals will not exceed those in Draft LR-ISG-2013-01, Appendix C, Table 4a.

Extent of Inspections

The extent of each inspection will be determined by a qualified coatings inspector based on an evaluation of the effect of a coating failure on the in-scope component's intended function(s), potential problems identified during prior inspections, and known service life history. Inspection locations are selected based on susceptibility to degradation and consequences of failure. The extent of inspections will not be any less than all accessible internal surfaces of tanks and heat exchangers. The inspection of piping will be no less than a representative 73 1-ft axial length circumferential segments of piping or 50 percent of the total length of each coating material and internal and external environments. The external environment is the material to which the coating is affixed. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased in order to cover an equivalent 73 1-foot axial length sections.

Coating surfaces captured between interlocking surfaces (e.g., flanges) are not required to be inspected unless the joint has been disassembled to allow access for an internal coating inspection or other reasons. For areas not readily accessible for direct inspection, such as small pipelines, heat exchangers, and other equipment, consideration is given to the use of remote or robotic inspection tools.

Inspection of coatings may be omitted for components where: (a) it has been determined that degradation of coatings cannot result in downstream effects on license renewal intended functions such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components, and (b) corrosion rates or inspection intervals of in scope components are not based on the integrity of the coating. For piping or tanks where degradation of the base metal is the only issue related to degradation of the components coating, then external wall

thickness measurements may be performed in lieu of visual inspection to confirm the acceptability of the corrosion rate of the base metal.

Coating Inspector Training and Qualification

The training and qualification of individuals involved in coating inspections and evaluating degraded conditions is conducted in accordance with an ASTM International standard endorsed in Regulatory Guide 1.54 including NRC guidance associated with a particular standard.

Monitoring and Trending of Coating Degradation

Monitoring and trending includes pre-inspection reviews of the previous two inspection results and any subsequent repair activities. The review will be performed by a coatings specialist and includes: (a) a list and location of all areas evidencing deterioration, (b) a prioritization of the repair areas into areas that must be repaired before returning the system to service, (c) areas where repair can be postponed to the next inspection, and (d) where possible, photographic documentation indexed to inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component and external wall thickness measurements are used in lieu of internal visual inspections of the coating, the corrosion rate of the base metal will be trended.

Acceptance Criteria

(1) Indications of peeling and delamination are not acceptable and the coatings are repaired or replaced. For coated surfaces that show evidence of delamination or peeling, physical testing is performed where physically possible. The test consists of destructive or nondestructive adhesion testing using ASTM International Standards. A minimum of three sample points adjacent to the defective area are tested.

(2) Blisters are evaluated by a coatings specialist. The cause of blisters needs to be determined if the blister is not repaired. Physical testing is conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister is inspected to determine if unanticipated corrosion has occurred.

(3) Indications such as cracking, flaking and rusting are to be evaluated by a coatings specialist.

(4) Minor cracking and spalling of cementitious coatings is acceptable provided there is no evidence that the coating is debonding from the base material.

(5) As applicable, wall thickness measurements meet design minimum wall requirements.

(6) Adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.

Corrective Action

Indications noted will be entered into the DCPP CAP for appropriate evaluation or disposition.

Coatings that do not meet acceptance criteria are repaired or replaced.

The DCPP fire water system contains galvanized piping (item number (14) above). The Fire Water System program will be used to demonstrate that an adequate amount of the zinc-based coating remains intact throughout the PEO. As discussed in Attachment 7C, 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, the obstruction investigation requires an internal inspection of fire water sprinkler piping (NFPA 25, Sections 14.2 and 14.3). The DCPP Fire Water System program will be enhanced to internally inspect wet sprinkler systems using a method capable of detecting flow blockage due to fouling in addition to loss of material. At least one of the three sections of fire water sprinkler piping fabricated from galvanized steel will be conducted during each inspection interval.

LRA Sections 3.3.2.1.3, 3.3.2.1.4, 3.3.2.1.5, 3.3.2.1.8, 3.3.2.1.12, 3.3.2.1.13, and 3.4.2.1.4 and Tables 3.3.2-3, 3.3.2-4, 3.3.2-5, 3.3.2-8, 3.3.2-12, 3.3.2-13, and 3.4.2-4 are revised as shown in this Attachment to identify systems and components with internal coatings. LRA Sections A1.9, A1.10, A1.13, and A1.22 and Table A4-1, Item 9, are revised as shown in Attachment 15 to identify aging management activities that will be performed to manage loss of coating integrity for in scope components with internal coatings. LRA Table A4-1, Item 74 is added as shown in Attachment 15.

3.3.2.1.3 Saltwater and Chlorination System

Materials

The materials of construction for the saltwater and chlorination system component types are:

- *Metallic with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following saltwater and chlorination system aging effects require management:

- *Loss of coating integrity*

3.3.2.1.4 Component Cooling Water System

Materials

The materials of construction for the component cooling water system component types are:

- *Metallic with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following component cooling water system aging effects require management:

- *Loss of coating integrity*

3.3.2.1.5 Makeup Water System

Materials

The materials of construction for the makeup water system component types are:

- *Metallic or cement with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following makeup water system aging effects require management:

- *Loss of coating integrity*

3.3.2.1.8 Chemical and Volume Control System

Materials

The materials of construction for the chemical and volume control system component types are:

- *Metallic with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

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

- *Loss of coating integrity*

3.3.2.1.12 Fire Protection System

Materials

The materials of construction for the fire protection system component types are:

- *Metallic or cement with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following fire protection system aging effects require management:

- *Loss of coating integrity*

3.3.2.1.13 Diesel Generator Fuel Oil System

Materials

The materials of construction for the diesel generator fuel oil system component types are:

- *Metallic with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following diesel generator fuel oil system aging effects require management:

- *Loss of coating integrity*

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
Piping	*LBS, PB*	*Carbon Steel (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Open-Cycle Cooling Water System (B2.1.9)*	*None*	*None*	*H, 3*
Valves	*LBS, PB*	*Carbon Steel (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Open-Cycle Cooling Water System (B2.1.9)*	*None*	*None*	*H, 3*

Plant Specific Notes:

3 *The Open-Cycle Cooling Water System (B2.1.9) program is used to monitor piping and valves fabricated of carbon steel (with internal coating or lining) with an internal environment of raw water (Int) for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8 in response to draft LR-ISG-2013-01, Appendix B, Table VII.*

Table 3.3.2-4 Auxiliary Systems – Summary of Aging Management Evaluation – Component Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (CCW Heat Exchanger)	*PB*	*Nickel-Alloys (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Open-Cycle Cooling Water System (B2.1.9)*	*None*	*None*	*H, 6*
Heat Exchanger (CCW Heat Exchanger)	*PB*	*Copper Alloy (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Open-Cycle Cooling Water System (B2.1.9)*	*None*	*None*	*H, 6*
Valve	*LBS, PB, SIA*	*Carbon Steel (with coating or lining)*	*Closed Cycle Cooling Water (Int)*	*Loss of coating integrity*	*Closed-Cycle Cooling Water System (B2.1.10)*	*None*	*None*	*H, 7*
Valve	*PB*	*Carbon Steel (with coating or lining)*	*Demineralized Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 8*
Valve	*PB*	*Copper Alloy (with coating or lining)*	*Closed Cycle Cooling Water (Int)*	*Loss of coating integrity*	*Closed-Cycle Cooling Water System (B2.1.10)*	*None*	*None*	*H, 7*
Valve	*PB*	*Stainless Steel (with coating or lining)*	*Closed Cycle Cooling Water (Int)*	*Loss of coating integrity*	*Closed-Cycle Cooling Water System (B2.1.10)*	*None*	*None*	*H, 7*

<u>Plant Specific Notes:</u>

6 *The Open-Cycle Cooling Water System (B2.1.9) program is used to monitor components of the CCW Heat Exchanger fabricated from nickel-alloys or copper alloys (with internal coating or lining) with an internal environment of raw water (Int) for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8 in response to draft LR-ISG-2013-01, Appendix B, Table VII.*

7 The Closed-Cycle Cooling Water System (B2.1.10) program is used to monitor valves fabricated of carbon steel, copper alloy, and stainless steel (with internal coating or lining) closed cycle cooling water (Int) for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8 in response to draft LR-ISG-2013-01, Appendix B, Table VII.

8 The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor carbon steel (with internal coating or lining) with an internal environment of demineralized water (Int) for loss of coating integrity . Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.

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
Piping	*PB*	*Asbestos Cement (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 6*
Tank	*LBS, PB*	*Carbon Steel (with coating or lining)*	*Demineralized Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 6*
Tank	*PB*	*Concrete (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 6*
Tank	*PB*	*Fiberglass*	*Demineralized Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 6*

Plant Specific Notes:

6 The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor tanks fabricated from concrete, fiberglass, and carbon steel (with coating or lining), and piping fabricated from asbestos cement (with internal coating or lining) for loss of coating integrity with an internal environment of demineralized water (Int) or raw water (Int) . Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.

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
Pulsation Dampener	*LBS*	*Elastomer*	*Secondary Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 10*
Heat Exchanger (Centrifugal Charging)	*PB*	*Carbon Steel (Galvanized)*	*Lubricating Oil (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 10*

Plant Specific Notes:

10 The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor pulsation dampers (with internal coating or lining) with an internal environment of secondary water (Int) and centrifugal charging heat exchanger (with internal coating or lining) with an internal environment of lubricating oil for loss of coating integrity . Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.

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
Piping	*PB*	*Asbestos Cement (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 5*
Piping	*PB*	*Carbon Steel (Galvanized)*	*Raw Water (Int)*	*Loss of coating integrity*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*
Tank	*PB*	*Carbon Steel (with coating or lining)*	*Raw Water (Int)*	*Loss of coating integrity*	*Fire Water System (B2.1.13)*	*None*	*None*	*H, 6*

Plant Specific Notes:

5 *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor asbestos concrete piping (with internal coating or lining) with an internal environment of raw water for loss of coating integrity . Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.*

6 *The Fire Water System (B2.1.13) program is used to monitor piping fabricated from carbon steel (with internal coating or lining) and tanks fabricated from carbon steel (with internal coating or lining) with an internal environment of raw water for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.*

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 (with coating or lining)*	*Fuel Oil (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 2*

Plant Specific Notes:

2 *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor tanks fabricated from carbon steel (with internal coating or lining) with an internal environment of fuel oil for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, Appendix B, Table VII.*

3.4.2.1.4 Condensate System

Materials

The materials of construction for the condensate system component types are:

- *Metallic with Service Level III (augmented) Internal Coating*

Aging Effects Requiring Management

The following condensate system aging effects require management:

- *Loss of coating integrity*

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Demineralizer	*LBS*	*Carbon Steel (with coating or lining)*	*Secondary Water (Int)*	*Loss of coating integrity*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*None*	*None*	*H, 5*

Plant Specific Notes:

5 *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting (B2.1.22) program is used to monitor condensate polisher demineralizers fabricated from carbon steel (with internal coating or lining) with an internal environment of secondary water for loss of coating integrity. Reference DCL-14-103, Enclosure 1, Attachment 8 in response to draft LR-ISG-2013-01, Appendix B, Table VIII.*

Updates to Reflect Installed Plant Equipment and Editorial Corrections

The annual review of components identified required changes in materials, environments, and other clarifications. As a result of the review, PG&E is revising the following LRA sections and tables. Unless otherwise indicated, LRA markups are provided in this Attachment.

(1) Section 2.1.2.2: During the development of the LRA, DCPP included all nonsafety-related SSCs in the auxiliary building, containment, and the fuel handling building as being within the scope of license renewal for Criterion (a)(2) spatial interaction considerations, except as discussed in LRA Sections 3.1.1 and 3.1.2. As a result, no room by room or any similar structure breakdown was required for these structures. However, engineering evaluations have determined that certain nonsafety-related SSCs are located such that there is no potential to impact safety-related SSCs. Inclusion of these nonsafety-related SSCs in the scope of License Renewal will present an undue burden for inspection or replacement. PG&E is updating its scoping and screening methodology to allow nonsafety-related systems and components that contain fluid or steam included in-scope for potential spatial interaction under criterion 10 CFR 54.4(a)(2), and are located inside structures that contain safety-related SSCs, to be scoped out if a component-specific engineering evaluation is performed. LRA Section 2.1.2.2 is updated to reflect this change in methodology.

(2) Section 2.3.2.4: The description of the control rod drive mechanism exhaust system is updated to reflect the replacement reactor head configuration. The replacement reactor heads were installed in Units 1 and 2 in 2010 and 2009, respectively.

(3) Table 3.3.2-3: During a review of design documents, PG&E determined that a portion of existing, in-scope, buried piping in the ASW system is super austenitic stainless steel and not carbon steel, as currently listed in Table 3.3.2-3. Table 3.3.2-3 is revised to include this material and environment combination of the existing in-scope piping. The aging management of this piping is discussed in Attachment 3.

(4) Table 3.3.2-5: In the makeup water system, PG&E has replaced the temporary PVC portable emergency eyewash stations with permanent emergency eyewash/shower stations made of stainless steel. Table 3.3.2-5 is revised to reflect this different material.

(5) Table 3.3.2-7: An editorial correction is made to specify the correct AMP number for the Selection Leaching of Materials AMP. PG&E has also removed an in-scope stainless steel valve from the plant. Since this valve

was the only in-scope stainless steel valve in the system with a leakage boundary spatial interaction function, an internal environment of demineralized water and an external environment of plant indoor air, the associated Table 3.3.2-7 line items are revised.

(6) Table 3.3.2-8: PG&E determined that Valve LWS-0-TCV-10 was actually Valve DC-0-08-P-V-CVCS-0-TCV-10, which was verified to already be in-scope of license renewal. LWS-0-TCV-10 had previously been evaluated and assigned a material of stainless steel. Table 3.3.2-8 line items pertaining to LWS-0-TCV-10 are being deleted.

(7) Table 3.3.2-9: PG&E determined that Valves VAC-1-442 and VAC-1-443 were no longer installed in the plant. The valve material is copper alloy and the intended function is structural integrity attached. The external environment is plant indoor air and the internal environment is ventilation atmosphere. Since these valves are the only ones in the system with an intended function of structural integrity attached, structural integrity attached is deleted from the applicable Table 3.3.2-9 line items.

(8) Table 3.3.2-11: PG&E determined that the material property for test connections PX-449 and PX-450 in the auxiliary building/heating, ventilation, and air conditioning system is carbon steel. Table 3.3.2-11 line items are added/modified to account for the associated material and environment combination.

(9) Table 3.3.2-12: PG&E determined that in-scope fire water sprinklers were brass (copper alloy greater than 15 percent Zn). Table 3.3.2-12 line items are revised to align the LRA with actual plant component information.

(10) Table 3.3.2-12 and Section A1.18: PG&E determined that Valve FP-0-1212 was not in-scope of license renewal because it is part of the fire protection system portion that is not relied upon in the fire hazards analysis. The valve material is stainless steel and the intended function is pressure boundary. The external environment is buried and the internal environment is raw water. Since this was the only buried stainless steel valve in the system, the associated line item is deleted from Table 3.3.2-12. Since the deleted component was the only non super austenitic stainless steel component in the scope of the Buried Piping and Tanks Inspection program, Section A1.18 is revised as shown in Attachment 15 to delete reference to visual inspection of stainless steel. The super austenitic stainless steel piping will be managed consistent with LR-ISG-2011-03 as described in Attachment 3.

(11) Table 3.3.2-18: PG&E determined that Sample Coolers -81 in Units 1 and 2 are in-scope of license renewal. Table 3.3.2-18 line items are added to reflect the sample coolers.

(12) Table 3.4.2-1: PG&E determined that the Steam Generator Blowdown Tanks are exposed to an environment of atmosphere/weather. Table 3.4.2-1 line items are revised to align the LRA with the actual plant configuration.

2.1.2.2 Title 10 CFR 54.4(a)(2) – Nonsafety-Related Affecting Safety-Related

Nonsafety-Related SSCs with Spatial Interaction with Safety-Related SSCs

The preventative option as implemented at DCPP is based on an approach for scoping of nonsafety-related SSCs having potential spatial interaction with safety-related SSCs. Potential spatial interaction is evaluated for any SSC in proximity to active or passive safety-related SSCs. The structures of concern for potential spatial interaction were identified based on the review of the CLB to determine which structures contained safety-related SSCs.

Nonsafety-related systems and components that contain fluid or steam, and are located inside structures that contain safety-related SSCs are included in scope for potential spatial interaction under criterion 10 CFR 54.4(a)(2) *unless scoped out by a component-specific engineering evaluation*.

2.3.2.4 Containment HVAC System

Control Rod Drive Mechanism (CRDM) Exhaust System

The purpose of the CRDM exhaust system is to remove heat from the CRDM area during normal plant operation. This system consists of *integrated shroud assemblies and cooling ducts, an air plenum, exhaust fans, and backdraft dampers*~~exhaust fans mounted on the removable CRDM shroud~~. This system is not designed to operate during accident conditions.

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	*PB*	*Stainless Steel*	*Buried (Ext)*	*Loss of material*	*Buried Piping and Tanks Inspection (B2.1.18)*	*VII.C1-16*	*3.3.1.29*	*E*

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
Eye Wash Sink	LBS	*Stainless Steel* ~~Polyvinyl Chloride (PVC)~~	Plant Indoor Air (Ext)	None	None	*VII.J-15*~~None~~	*3.3.1.94* ~~None~~	~~F~~*C*
Eye Wash Sink	LBS	*Stainless Steel* ~~Polyvinyl Chloride (PVC)~~	Plant Indoor Air (Int)	None	None	None	None	~~F~~*G*

Table 3.3.2-7 Auxiliary Systems – Summary of Aging Management Evaluation – Compressed Air System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Regulators	PB	Copper Alloy (> 15% Zinc)	Atmosphere/ Weather (Ext)	Loss of material	Selective Leaching of Materials (B2.1.~~18~~17)	None	None	G
~~Valve~~	~~LBS~~	~~Stainless Steel~~	~~Demineralized Water (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~VIII.E-29~~	~~3.4.1.16~~	~~A~~
Valve	~~LBS,~~ PB, SIA	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A

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
~~Valve~~	~~LBS, SIA~~	~~Stainless Steel~~	~~Steam (Int)~~	~~Cracking~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~VIII.B1-2~~	~~3.4.1.39~~	~~E, 5~~
~~Valve~~	~~LBS, SIA~~	~~Stainless Steel~~	~~Steam (Int)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~VIII.B1-3~~	~~3.4.1.37~~	~~E, 5~~

Table 3.3.2-9 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous HVAC Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve	~~SIA,~~ SS	Copper Alloy	Plant Indoor Air (Ext)	None	None	VIII.I-2	3.4.1.41	C
Valve	~~SIA,~~ SS	Copper Alloy	Ventilation Atmosphere (Int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)	VII.G-9	3.3.1.28	E

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Test Connection	*LBS*	*Carbon Steel*	*Plant Indoor Air (Ext)*	*Loss of material*	*External Surfaces Monitoring Program (B2.1.20)*	*VII.I-8*	*3.3.1.58*	*B*
Test Connection	*LBS*	*Carbon Steel*	*Plant Indoor Air (Int)*	*Loss of material*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)*	*VII.G-23*	*3.3.1.71*	*B*
Test Connection	~~LBS,~~ SIA	Stainless Steel	Plant Indoor Air (Ext)	None	None	VII.J-15	3.3.1.94	A
~~Test Connection~~	~~LBS~~	~~Stainless Steel~~	~~Plant Indoor Air (Int)~~	~~Loss of material~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.22)~~	~~VII.F2-1~~	~~3.3.1.27~~	~~E~~

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
Spray Nozzle	SP	~~Carbon Steel~~ *Copper Alloy (> 15% Zinc*	Atmosphere/ Weather (Int)	Loss of Material	~~External Surfaces Monitoring Program (B2.1.20)~~ *Selective Leaching of Materials (B2.1.17)*	~~VII.I-9~~ *None*	~~3.3.1.58~~ *None*	~~B~~G
Spray Nozzle	SP	~~Carbon Steel~~ *Copper Alloy (> 15% Zinc*	Atmosphere/ Weather (Ext)	Loss of Material	~~External Surfaces Monitoring Program (B2.1.20)~~ *Selective Leaching of Materials (B2.1.17)*	~~VII.I-9~~ *None*	~~3.3.1.58~~ *None*	~~B~~G
Spray Nozzle	SP	~~Stainless Steel~~ *Copper Alloy (> 15% Zinc)*	Plant Indoor Air (Ext)	None	None	~~VII.J-15~~ *VIII.I-2*	~~3.3.1.94~~ *3.4.1.41*	A
Spray Nozzle	SP	~~Stainless Steel~~ *Copper Alloy (> 15% Zinc)*	Plant Indoor Air (Int)	None	None	None	None	G
Spray Nozzle	*SP*	*Copper Alloy (> 15% Zinc)*	*Raw Water (Int)*	*Loss of Material*	*Selective Leaching of Materials (B2.1.17)*	*VII.G-13*	*3.3.1.84*	*A*
~~Valve~~	~~PB~~	~~Stainless Steel~~	~~Buried (Ext)~~	~~Loss of material~~	~~Buried Piping and Tanks Inspection (B2.1.18)~~	~~VII.G-20~~	~~3.3.1.29~~	~~E~~

Table 3.3.2-18 Auxiliary Systems – Summary of Aging Management Evaluation – Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat Exchanger (Sample Cooler)	*LBS*	*Stainless Steel*	*Plant Indoor Air (Ext)*	*None*	*None*	*VIII.I-10*	*3.4.1.41*	*A*
Heat Exchanger (Sample Cooler)	*LBS*	*Stainless Steel*	*Secondary Water (Int)*	*Loss of material*	*Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)*	*VIII.C-1*	*3.4.1.16*	*A*
Heat Exchanger (Sample Cooler)	*LBS*	*Stainless Steel*	*Secondary Water (Int)*	*Cracking*	*Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)*	*VIII.C-2*	*3.4.1.14*	*A*
Heat Exchanger (Sample Cooler)	*LBS*	*Stainless Steel*	*Closed Cycle Cooling Water (Int)*	*Loss of material*	*Closed-Cycle Cooling Water (B2.1.10)*	*VIII.E-24*	*3.4.1.25*	*B*
Heat Exchanger (Sample Cooler)	*LBS*	*Stainless Steel*	*Closed Cycle Cooling Water (Int)*	*Cracking*	*Closed-Cycle Cooling Water (B2.1.10)*	*VIII.E-25*	*3.4.1.23*	*B*

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tank	*SIA*	*Carbon Steel*	*Atmosphere/ Weather (Ext)*	*Loss of material*	*External Surfaces Monitoring Program (B2.1.20)*	*VIII.H-7*	*3.4.1.28*	*B*

Removal of Caustic Dilution Heat Exchanger Tubes Exposed to Secondary Water from Scope of License Renewal

LRA Section 2.3.4.4 states that high energy portions of the condensate system in the turbine building are in the scope of license renewal since they could prevent the satisfactory accomplishment of a safety-related function associated with certain safety-related cables. LRA Table 3.4.2-4 is revised to remove the caustic dilution heat exchanger tube sheet exposed to secondary water from the scope of license renewal since the tube sheet is not a high energy portion of the condensate system. The caustic dilution heat exchanger shell (steam side) will appropriately remain in the scope of license renewal. Refer to revised LRA Table 3.4.2-4 in this Attachment.

Table 3.4.2-4 Steam and Power Conversion System – Summary of Aging Management Evaluation – Condensate System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~Heat Exchanger (Caustic Dilution Hx – Tubesheet)~~	~~LBS~~	~~Copper Alloy~~	~~Secondary Water (Ext)~~	~~Loss of material~~	~~Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16)~~	~~VIII.A-5~~	~~3.4.1.15~~	~~C~~

Update to Reflect WCAP-17103 Revisions that Addressed Regulatory Issue Summary 2011-14 Regarding User Intervention in Westems™.

In December 2011, the NRC issued RIS 2011-14, "Metal Fatigue Analysis Performed by Computer Software." This RIS was concerned with Westinghouse Westems™ software, which allows for a user to manually modify stress peak and valley times in the total stress intensity time history used to calculate the cumulative usage factor.

WCAP-17103, "Diablo Canyon Unit 1 Insurge/Outsurge and Environmental Fatigue Evaluations" and WCAP-17104, "Diablo Canyon Unit 2 Insurge/Outsurge and Environmental Fatigue Evaluations" were completed for license renewal and used the Westinghouse Westems™ software. Both WCAPs were revised to justify user intervention when calculating the fatigue usage. New analyses were performed for Units 1 and 2 to clearly demonstrate the peak selection process. For Unit 1 (WCAP-17103), the new analysis resulted in a change to the calculated pressurizer heater penetration cumulative usage factor. The component remains qualified. The new Unit 2 analysis did not result in any cumulative usage factor changes. Refer to revised LRA Tables 4.3-1 and 4.3-6 and Section 4.9 in this Attachment.

Table 4.3-1 Summary of Monitored Fatigue Usage, and Method of Management by the Enhanced DCPP Fatigue Management Program

Component	**Maximum Design CUF**		**Fatigue Management Method**
	Unit 1	**Unit 2**	
RPV Closure Studs	0.7537	0.7537	Global
Inlet Nozzle / Support Pad[a]	0.142	0.142	Global
Outlet Nozzle / Support Pad[a]	0.311	0.311	Global
RPV Core Support Pads	0.892	0.892	Global
RPV Bottom Head to Shell[a]	0.0102	0.0102	CBF
Hot Leg Surge Nozzle[a]	0.5387	0.5387	CBF
Pressurizer Spray Nozzle	0.9469	0.7840	Global
Pressurizer Heater Penetration	~~0.9391~~*0.9598*	0.5442	Global
Unit 2 Pressurizer Upper Head and Shell	NA	0.7598	Global
RCS Cold Leg Charging Line Nozzle[a]	0.0641	0.0641	CBF
Accumulator Safety Injection Nozzle[a][b]	2.6353	2.6353	CBF
RHR-to-Accumulator Safety Injection Line Tee[a]	0.0093381	0.0093381	CBF

(a) Location is a NUREG/CR-6260 location for older vintage Westinghouse plants
(b) For further discussion of the Accumulator Safety Injection Nozzle design CUF of greater than 1.0, refer to Section 4.3.4.

Table 4.3-6 Summary of DCPP Pressurizer ASME Section III Class A Analyses and Fatigue Usage Factors

Component Analysis	**Limiting Location CUF**			
	Unit 1		**Unit 2**	
	50-Year Value	**60-Year Projection[a]**	**50-Year Value**	**60-Year Projection[a]**
Surge Nozzle Analysis	0.2288	0.2746	0.2201	0.2641
Spray Nozzle Analysis	0.9469	1.13628	0.784	0.9408
Safety and Relief Nozzle Analysis	0.0062	0.00744	0.069	0.0828
Lower Head Welds[b]	Head to Shell 0.2304	Head to Shell 0.2765	Head to Shell 0.088 Head to Surge Nozzle 0.2276	Head to Shell 0.1056 Head to Surge Nozzle 0.2731
Heater Penetration	2.9643	~~0.9391~~*0.9598*[€]	0.5443	0.6532
Upper Head and Shell Analysis[b]	0.2869	0.34428	0.7498	0.8997
Support Skirt and Flange Analysis	0.0045	0.0054	0.0045	0.0054
Support Lug Analysis	0.269 (lug), 0.188 (shell)	0.3228 (lug), 0.2256 (shell)	0.269 (lug), 0.188 (shell)	0.3228 (lug), 0.2256 (shell)
Manway Analysis	0.00	-	S_a < endurance limit[d]	-
Upper Instrument Nozzle Analysis	0.121	0.1452	0.121	0.1452
Lower Instrument Nozzle Analysis	0.0424	0.05088	0.08672	0.0037
Immersion Heater Analysis	0.005	0.006	0.005	0.0060
Valve Support Bracket Analysis[€]	NA	NA	0.0418	0.0502

(a) 60-year Projection = 50-year Design CUF x 1.2
(b) The Unit 1 pressurizer upper and lower heads are cast. The Unit 2 pressurizer upper and lower heads are fabricated.
(c) This value is the result of a fatigue analysis performed using the 60-year projected number of transients instead of the design basis numbers of transients.
(d) An alternating stress (Sa) less than the endurance limit indicates that there is no fatigue life associated with this components.
(e) Unit 1 has no such support bracket.

4.9 REFERENCES

20. Westinghouse Report WCAP-17103. *Diablo Canyon Unit 1 Insurge/Outsurge and Environmental Fatigue Evaluations*. Rev. ~~1~~4. *May 2013*~~October 2009~~. Westinghouse Proprietary Class 2.

Reactor Coolant Pump Flywheel Inspection Interval

The current TLAA for the RCP flywheel relies on use of NRC Staff-approved WCAP-14535-A to relax the inspection requirements for the RCP flywheel. As stated in LRA Section 4.7.4 and SER Section 4.7.4, WCAP-14535-A performed an evaluation of the probability of failure over the PEO for all operating Westinghouse plants. It demonstrates that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension assuming 6,000 pump starts over a 60-year life. Since the evaluation is based on the 60-year operating period, the TLAA covers the PEO and is dispositioned under 10 CFR 54.21(c)(1)(i).

By letter "Diablo Canyon Power Plant, Unit Nos. 1 and 2 – Issuance of Amendments Re: Revision to Technical Specification 5.5.7, 'Reactor Coolant Pump Flywheel Inspection Program,' in Accordance with TSTF-421A, Revision 1," dated September 5, 2013, the NRC Staff issued Amendment Nos. 216 and 218 to the Units 1 and 2 facility operating licenses, respectively to rely on the analysis provided in WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination."

LRA Sections 4.7.4 and 4.9 are revised to reflect License Amendments 216 and 218. LRA Section 4.7.4 is also revised to reflect an additional change in response to request for additional information 4.1-2 in PG&E Letter DCL-10-123, "Response to NRC Letter dated August 30, 2010, 'Request for Additional Information (Set 21) for the Diablo Canyon License Renewal Application,'" dated September 29, 2010.

Refer to revised LRA Sections 4.7.4 and 4.9 in this Attachment.

4.7.4 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis Summary Description

NUREG-1800 identifies "Fatigue analysis of the reactor coolant pump flywheel" as a potential TLAA.

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles inside containment and could also damage pump seals or other pressure boundary components in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway. This concern is the subject of Regulatory Guide 1.14, *Reactor Coolant Pump Flywheel Integrity*. ~~At DCPP, flywheel fatigue is a recognized aging effect, but the aging effect is not the subject of a TLAA.~~

The original DCPP SER, NUREG-0675, states that the RCP motor flywheel is designed to meet the guidelines of Regulatory Guide 1.14. The DCPP flywheel design and its compliance with Regulatory Guide 1.14 is described in the FSAR Section 5.2.6. The inspection recommendations are incorporated in the DCPP ISI Program and are required by the TS.

To reduce the inspection frequency and scope, DCPP amended its initial compliance with Regulatory Guide 1.14 by implementing WCAP-~~14535~~*15666*-A [Reference 9], which supports relaxation of the inspection required by Regulatory Guide 1.14 Position C.4.b(1) and (2). The NRC has reviewed and accepted this topical report for use in license renewal applications. This relaxation was approved for DCPP ~~with the Improved TS conversion~~ [Reference 12] and was incorporated into the DCPP ISI Program and the TS.

Analysis
WCAP-~~14535~~*15666*-A [Reference 9] performed an evaluation of the probability of failure over the period of extended operation for all operating Westinghouse plants. It demonstrates that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension assuming 6,000 pump starts over a 60 year life. Since the evaluation is based on the 60-year operating period, the TLAA covers the period of extended operation and is dispositioned under 10 CFR 54.21€(1)(i).

Disposition: Validation, 10 CFR 54.21€(1)(i)
Using a conservative projection of 1,000 cycles for a 60 year plant life, the 6,000 events assumed in the fatigue crack growth analysis for the reactor coolant pump flywheels during 60 years of operation is conservative. The analysis is valid for the period of extended operation in accordance with 10 CFR 54.21€(1)(i).

4.9 REFERENCES

9. ~~Westinghouse Report WCAP-14535-A. Westinghouse Topical Report. P. L. Strauch et al. *Topical Report on Reactor Coolant Pump Motor Flywheel Inspection Elimination*. Pittsburgh: Westinghouse, November 1996.~~
Westinghouse Report WCAP-15666-A, Revision 1. Westinghouse Topical Report. P.L. Strauch et al. Extension of Reactor Coolant Pump Motor Flywheel Examination. Pittsburgh: Westinghouse, October 2003.

12. ~~US NRC Letter. From Jack N. Donohew, Senior Project Manager, Section 1, Project Directorate IV & Decommissioning, Division of Licensing Project Management, Office of Nuclear Reactor Regulation; to Mr. Gregory M. Rueger, Senior Vice President and General Manager, DCPP. "Conversion to Improved Technical Specifications for Diablo Canyon Power Plant, Units 1 and 2 – Amendment No. 135 to Facility Operating License Nos. DPR 80 and DPR 82 (TAC Nos. M98984 and M98985)." 28 May 1999.~~
US NRC Letter. From Jennie K. Rankin, Project Manager, Plant Licensing Branch IV, Division of Operating Reactor Licensing, Office of Nuclear Reactor Regulation; to Mr. Edward D. Halpin, Senior Vice President and Chief Nuclear Officer, DCPP. "Diablo Canyon Power Plant, Unit Nos. 1 and 2 – Issuance of Amendments Re: Revision to Technical Specification 5.5.7, "Reactor Coolant Pump Flywheel Inspection Program," in Accordance with TSTF-421-A,

Flow-Accelerated Corrosion Program (B2.1.6)

PG&E revises the DCPP FAC program to address NSAC-202L-R4.

Background

In PG&E Letter DCL-09-079, Enclosure 1, Appendix B2.1.6, PG&E took an exception to NUREG-1801, Scope of Program – Element 1 and Detection of Aging Effects – Element 4, as follows:

> "NUREG-1801, Section XI.M17, states that the FAC program should be based on the recommendations in NSAC-202L-R2. The guidelines provided in the governing procedure are based on the recommendations provided in the EPRI Guideline NSAC-202L-R3. The third revision of NSAC-202L contains recommendations updated with the experience of members of the CHECWORKS Users Group (CHUG), plus recent developments in detection, modeling, and mitigation technology. These recommendations are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs. The guidance contained in the third revision of NSAC-202L supersedes that contained in all prior versions of NSAC-202L."

In letter, "Safety Evaluation Report Related to the License Renewal of Diablo Canyon Nuclear Power Plant, Units 1 and 2," dated June 2, 2011, Section 3.0.3.2.2, "Flow Accelerated Corrosion," the NRC Staff found EPRI NSAC-202L-R3 acceptable because it will continue to allow the applicant to manage wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon and low alloy steel piping and components that contain both single-phase and two-phase, high-energy fluids.

PG&E revises its exception to NUREG-1801, Scope of Program – Element 1 and Detection of Aging Effects – Element 4, to utilize the guidelines provided in the governing procedure based on the recommendations provided in the EPRI Guideline NSAC-202L-R4. The recommendations in NSAC-202L-R4 are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs. The guidance contained in NSAC-202L-R4 supersedes that contained in all prior versions of NSAC-202L. PG&E also revises NSAC-202L's revision from Revision 3 to Revision 4 in LRA Section A1.6 as shown in Attachment 15.

License Renewal Application Chapter 2 Update to Address LR-ISGs

As shown on the following pages, LRA Section 2.1.5, "Interim Staff Guidance" is updated to add LR-ISG-2011-01 through LR-ISG-2011-05; LR-ISG-2012-01 and LR-ISG-2012-02; and Draft LR-ISG-2013-01 to LRA Table 2.1-2, "NRC Interim Staff Guidance Associated with License Renewal." LRA Sections 2.1.5.8 through 2.1.5.15 were added to provide a summary discussion of the LR-ISGs added to LRA Table 2.1-2.

2.1.5 Interim Staff Guidance

Table 2.1-2 NRC Interim Staff Guidance Associated with License Renewal

Issue Number	Purpose	Discussion Status
LR-ISG-2011-01	*Aging Management of Stainless Steel Structures and Components in Treated Borated Water*	*The staff has issued LR-ISG-2011-01, Revision 1*
LR-ISG-2011-02	*Aging Management Program for Steam Generators*	*The staff has issued LR-ISG-2011-02*
LR-ISG-2011-03	*Aging Management Program for Buried and Underground Piping and Tanks*	*The staff has issued LR-ISG-2011-03*
LR-ISH-2011-04	*Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors*	*The staff has issued LR-ISG-2011-04*
LR-ISG-2011-05	*Ongoing Review of Operating Experience*	*The staff has issued LR-ISG-2011-05*
LR-ISG-2012-01	*Wall Thinning Due to Erosion Mechanisms*	*The staff has issued LR-ISG-2012-01*
LR-ISG-2012-02	*Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation*	*The staff has issued LR-ISG-2012-02*
LR-ISG-2013-01	*Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings*	*The staff has issued for public comment draft LR-ISG–2013-01*

2.1.5.8 (LR-ISG-2011-01) Aging Management of Stainless Steel Structures and Components in Treated Borated Water

The staff has issued this LR-ISG to provide guidance as to one acceptable approach for managing the effects of aging during the period of extended operation for stainless steel structures and components exposed to treated borated water within the scope of license renewal. This LR-ISG is discussed in PG&E Letter DCL-14-103.

2.1.5.9 (LR-ISG-2011-02) Aging Management Program for Steam Generators

The staff has issued this LR-ISG to evaluate the suitability of using Revision 3 of NEI 97-06 to manage steam generator aging and to correct an incorrect revision in NUREG-1801, Revision 2, to the Steam Generator Integrity Assessment Guidelines. This LR-ISG is discussed in PG&E Letter DCL-14-103.

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

The staff has issued this LR-ISG to provide one acceptable approach for managing the effects of aging of buried and underground piping and tanks within the scope of the License Renewal Rule. This LR-ISG is discussed in PG&E Letter DCL-14-103.

2.1.5.11 (LR-ISG-2011-04) Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors

The staff issued this LR-ISG to revise the recommendations in the GALL Report and the NRC Staff's acceptance criteria and review procedures in the SRP-LR to ensure consistency with MRP-227-A. This LR-ISG also provides a framework to ensure that PWR license renewal applicants will adequately address age-related degradation and aging management of reactor vessel internal components during the term of the renewed license. This LR-ISG is discussed in PG&E Letter DCL-14-103.

2.1.5.12 (LR-ISG-2011-05) Ongoing Review of Operating Experience

The staff issued this LR-ISG to provide a framework to ensure that license renewal applicants' operating experience review activities will adequately address operating experience concerning age-related degradation and aging management during the term of the renewed license. This LR-ISG is discussed in PG&E Letter DCL-14-103.

2.1.5.13 (LR-ISG-2012-01) Wall Thinning Due to Erosion Mechanisms

The staff issued this LR-ISG to provide interim guidance for an approach acceptable to the NRC Staff to manage the effects of aging during the period of extended operation for wall thinning due to various erosion mechanisms for piping and components within the scope of the License Renewal Rule. This LR-ISG is discussed in PG&E Letter DCL-14-103.

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

The staff issued this LR-ISG to provide an acceptable approach for managing the associated aging effects for components within the scope of the License Renewal Rule. This LR-ISG is discussed in PG&E Letter DCL-14-103.

2.1.5.15 (LR-ISG-2013-01) Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings

This draft LR-ISG was issued in draft for public comment. This draft LR-ISG provides an acceptable approach for managing loss of coating integrity in service level III (augmented) coatings for components within the scope of the License Renewal Rule. This draft LR-ISG is discussed PG&E Letter DCL-14-103.

LRA Appendix A, "Final Safety Analysis Report Supplement"

This Attachment contains revisions to LRA Appendix A resulting from the 2014 DCPP LRA Update. Below is a basis for the changes or a reference to the Attachment that contains the basis.

(1) Section A1: Refer to Attachment 5, "LR-ISG-2011-05, 'Ongoing Review of Operating Experience.'"

(2) Section A1.2: The Water Chemistry Program FSAR Supplement is updated to add the aging effect of reduction of heat transfer listed in LRA Chapter 3 Tables.

(3) Section A1.6:

(a) Refer to Attachment 6, "LR-ISG-2012-01, 'Wall Thinning Due to Erosion Mechanisms.'"

(b) Refer to Attachment 13, "Flow-Accelerated Corrosion Program (B2.1.6)." PG&E revises NSAC-202L Revision 3 to Revision 4.

(4) Section A1.9:

(a) The Open Cycle Cooling Water System program FSAR Supplement is revised to clarify that the program is consistent with PG&E Letters DCL-90-027, dated January 26, 1990, and DCL-91-286, dated November 25, 1991, in response to NRC Generic Letter 89-13 regarding performance testing of the component cooling water heat exchangers.

(b) Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'"

(5) Section A1.10: Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'"

(6) Section A1.13:

(a) Refer to Attachment 7C, "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.'"

(b) Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'"

(7) Section A1.15: Refer to Attachment 17. In order for PG&E to participate in the EPRI PWR Supplemental Surveillance Program, the donated specimens will no longer be stored.

(8) Section A1.16: Refer to Attachment 16, "One-Time Inspection." PG&E adopts the NUREG-1801, Revision 2 sample size where the One-Time Inspection program verifies the effectiveness of the DCPP Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis programs."

(9) Section A1.18:

(a) Refer to Attachment 3, "LR-ISG-2011-03, 'Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, 'Buried and Underground Piping and Tanks.''"

(b) Refer to Attachment 9. Section A1.18 is revised to delete reference to visual inspection of stainless steel.

(10) Section A1.20: Refer to Attachment 7E, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section E, "Corrosion Under Insulation."

(11) Section A1.22:

(a) Refer to Attachment 7A, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section A, "Recurring Internal Corrosion."

(b) Refer to Attachment 7B, "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.'"

(c) Refer to Attachment 7D, "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 Tank.'"

(d) Refer to Attachment 7F, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section F, "External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, Buried and Underground Piping and Tanks."

(e) Refer to Attachment 7G, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation.'" Section G, "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38." Visual inspections may be augmented by sufficient pressurization of the elastomer material to expand the surface in such a way that cracks or crazing is evident.

(f) Refer to Attachment 7H, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section H, "Key Miscellaneous Changes to the GALL Report and SRP-LR."

(g) Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'"

(12) Section A1.41: Refer to Attachment 4, "LR-ISG-2011-04, 'Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors.'"

(13) Table A4-1, Item 3: Refer to Attachment 7C, "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.'"

(14) Table A4-1, Item 8: Refer to Attachment 7E, "LR-ISG-2012-02, 'Aging Management if Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section E, "Corrosion Under Insulation."

(15) Table A4-1, Item 9:

(a) Refer to Attachment 7A, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section A, "Recurring Internal Corrosion."

(b) Refer to Attachment 7B, "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.'" Implementation schedule is changed from prior to the PEO to six months prior to the PEO.

(c) Refer to Attachment 7D, "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 Tank.'"

(d) Refer to Attachment 7F, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section F, "External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, Buried and Underground Piping and Tanks."

(e) Refer to Attachment 7G, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation.'" Section G, "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38." Visual inspections may be augmented by sufficient pressurization of the elastomer material to expand the surface in such a way that cracks or crazing is evident.

(f) Refer to Attachment 7H, "LR-ISG-2012-02, 'Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,'" Section H, "Key Miscellaneous Changes to the GALL Report and SRP-LR."

(g) Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'"

(16) Table A4-1, Item 20: Refer to Attachment 5, "LR-ISG-2011-05, 'Ongoing Review of Operating Experience.'"

(17) Table A4-1, Item 22 (Reactor Vessel Internals): Refer to Attachment 4, "LR-ISG-2011-04, 'Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors.'"

(18) Table A4-1, Item 32: This item is complete. A DCPP plant procedure was revised to perform concrete inspections per ASME Section XI, Subsection IWL within a five-year interval.

(19) Table A4-1, Item 48: Refer to Attachment 16, "One-Time Inspection." PG&E deleted this commitment because PG&E will determine the nondestructive examination of a representative sample size of 20 percent of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components.

(20) Table A4-1, Item 52: Refer to Attachment 3, "LR-ISG-2011-03, 'Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, 'Buried and Underground Piping and Tanks.''"

(21) Table A4-1, Item 64: This item is complete. The existing indication was examined during the seventeenth refueling outage in Unit 2. The examination confirmed the absence of service-related flaw growth. Results of the examination were reported to the NRC in PG&E Letter DCL-12-089, "Inservice Inspection Report for Unit 1 Seventeenth Refueling Outage," dated September 13, 2012. WIC-95 will continue to be inspected at a frequency required by the Inservice Inspection Program Plan.

(22) Table A4-1, Items 66 and 68:

As discussed in PG&E Letter DCL-11-037, dated March 25, 2011, PG&E committed to revising the flux thimble tube inspections plant procedure to, in part, include a 5 percent allowance for predictability and to use a net acceptance criterion of 65 percent (LRA Table A4-1, Items 65 and 68). In PG&E Letter DCL-12-124, dated December 20, 2012, PG&E indicated these commitments were complete.

During the Unit 1 18th refueling outage, which began in February 2014, a flux thimble tube scheduled for replacement was found to have a wear scar that was 5.1 percent over the predicted value. Because the actual wear was greater than 5 percent of the predicted wear, it was entered into the DCPP Corrective Action Program for evaluation and disposition. The evaluation concluded that the predictability allowance should be revised to 5.1 percent to account for the new plant-specific wear data. All other acceptance criteria remained the same.

As discussed in PG&E Letter DCL-11-037, WCAP-12866 recommended an 80 percent through wall acceptance criterion. This value includes an additional safety margin established by Westinghouse for allowable wear in the thimble tube. WCAP-12866 did not require adding an allowance for eddy current testing instrument uncertainties. Based on the WCAP-12866 80 percent acceptance criterion, including the revised 5.1 percent predictability uncertainty and 10 percent for eddy current testing instrument and wear scar uncertainty, PG&E will use a revised net acceptance criterion of 64.9 percent. The revised acceptance criteria provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained.

The flux thimble tube inspections procedure revision was completed in August 2014. The subject flux thimble tube was replaced, as-scheduled, in the Unit 1 18th refueling outage.

LRA Table A4-1, Items 66 and 68, are updated to address the revised flux thimble tube acceptance criteria and completion of the procedure revision.

(23) Table A4-1, Items 72 and 73: Refer to Attachment 4, "LR-ISG-2011-04, 'Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors.'"

(24) Table A4-1, Item 74: Refer to Attachment 8, "Draft LR-ISG-2013-01, 'Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings.'" PG&E will conform to Draft LR-ISG-2013-01 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 8.

A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

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

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

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

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

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

(2) *Plant-specific and incoming industry operating experience will be screened to determine whether they may involve age-related degradation or aging management impacts. Sources of industry operating experience will include License Renewal Interim Staff Guidance (LR-ISG) documents; all revisions to NUREG-1801; and other NRC and industry guidance documents and standards applicable to aging management, such as Information Notices, Regulatory Issue Summaries, etc.*

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

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

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

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

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

adequately managed, the CAP will be used to either enhance the AMP or develop and implement new AMPs.

(8) Initial and periodic training on age-related degradation and aging management will be provided to those personnel responsible for implementing the AMPs and personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience.

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

A1.2 WATER CHEMISTRY

The Water Chemistry program manages loss of material~~, and~~ cracking*, and reduction of heat transfer* in the primary and secondary water systems. The program relies on monitoring and control of primary and secondary water chemistry to mitigate damage caused by corrosion and stress corrosion cracking. The Water Chemistry program is a mitigation program and does not provide for the detection of aging effects. Inspections of selected components at susceptible locations in a system (e.g., at low flow or stagnant areas) performed under the separate One-Time Inspection program (A1.16) provide verification of the effectiveness of the Water Chemistry program. The Water Chemistry program is based on the guidelines of EPRI TR-105714, Revision 6 (issued as TR-1014986), *PWR Primary Water Chemistry Guidelines*, and EPRI TR-102134, Revision 7 (issued as TR-1016555), *PWR Secondary Water Chemistry Guidelines* or later revisions.

A1.6 FLOW ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon steel piping, elbows, reducers, expanders, and valve bodies which contain ~~high energy fluids (~~both single phase and two phase~~s)~~ *fluids*. Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to flow accelerated corrosion are used to predict the amount of wall thinning. The program includes analyses to determine critical locations. Initial inspections are performed to determine the extent of thinning at these critical locations, and follow-up inspections are used to confirm the predictions. Inspections are performed using ultrasonic and/or radiographic inspection techniques capable of detecting wall thinning. Repairs and replacements are performed as necessary.

Where applicable, the program also manages wall thinning due to erosion mechanisms such as cavitation, flashing, droplet impingement, and solid particle impingement. Susceptible locations with be identified based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry operating experience. The effectiveness of corrective actions for which design changes have been implemented to eliminate the source of erosion will periodically verified until the effectiveness of the corrective action has been has been confirmed. The FAC program implements the recommendations in LR-ISG-2012-01, as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 6.

The FAC program is based on EPRI guidelines in NSAC-202L-R~~3~~*4*, *Recommendations for an Effective Flow-Accelerated Corrosion Program*. Procedures and methods used by the FAC program are consistent with DCPP's commitments to NRC Bulletin 87-01, *Thinning of Pipe Wall in Nuclear Power Plants*, and NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

A1.9 OPEN CYCLE COOLING WATER SYSTEM

The Open-Cycle Cooling Water System program manages cracking, loss of material, ~~and~~ reduction of heat transfer for components*, and loss of integrity for Service Level III (augmented) internal coatings* that are exposed to the raw water of the DCPP OCCW system. The DCPP OCCW system is the auxiliary saltwater (ASW) system. Components within the scope of the OCCW System program are components of the ASW system and the component cooling water heat exchangers that are cooled by the ASW system. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in components of the ASW system or structures and components serviced by the ASW system that are within the scope of license renewal. The program also includes periodic visual inspections and non-destructive examinations to detect biofouling, defective coatings, and degraded piping and components of, systems and components.~~, and~~ *The program also currently performs periodic* CCW heat exchanger performance testing~~,~~ to ensure that the effects of aging on components are adequately managed for the period of extended operation. The program is consistent with commitments as established in *PG&E Letters DCL-90-027, dated January 26, 1990, and DCL-91-286, dated November 25, 1991,* ~~DCPP~~ *in* response~~s~~ to NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, including Supplement 1.

As discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, the program includes visual inspections of Service Level III (augmented) internal coatings. For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the NRC associated with a particular standard.

A1.10 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System program manages loss of material, cracking, ~~and~~ reduction in heat transfer, *and loss of integrity for Service Level III (augmented) internal coatings* for components within the scope of license renewal in closed-cycle cooling water systems. The program includes maintenance of system chemistry parameters following the guidance of EPRI TR-107396, Revision 1, *Closed Cooling Water Chemistry Guidelines (EPRI-1007820)* to minimize aging. The program provides for: (1) preventive measures to minimize corrosion including maintenance of corrosion inhibitor, pH buffering agent, and biocide concentrations, and (2) periodic system and component performance testing and inspection. Periodic inspection and testing to confirm function and monitor corrosion is performed in accordance with EPRI TR 107396, Revision 1 (EPRI 1007820), and industry and plant operating experience.

As discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 8, in response to draft LR-ISG-2013-01, the program includes visual inspections of Service Level III (augmented) internal coatings. For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the NRC associated with a particular standard.

A1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material due to corrosion, *including* MIC, ~~or bio~~fouling, *flow blockage because of fouling, and loss of integrity for Service Level III (augmented) internal coatings* for water-based fire protection systems. Internal and external inspections and tests of fire protection equipment are performed *consistent, with exceptions identified in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C, with* ~~considering applicable National Fire Protection Association (~~NFPA*-25 (2011 edition)*~~) codes and standards~~. *Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA-25 (2011 edition). Portions of the deluge systems that are normally dry but periodically subjected to flow and cannot be drained or allow water to collect will undergo augmented testing beyond that in NFPA-25 consisting of volumetric wall thickness examinations.* The fire water system is managed by performing routine preventive maintenance, inspections~~,~~ and testing; operator rounds, performance monitoring, and reliance on the corrective action program; and system improvements to address aging and obsolescence issues.

The Fire Water System program *will* conduct~~s~~ a ~~water~~ flow test *with air, water, or other medium* through each open spray nozzle to verify that deluge systems *nozzles are unobstructed. Water flow tests will verify that the deluge system* provide full coverage of the equipment it protects. ~~Either periodic non-intrusive volumetric examinations or v~~*V*isual inspections will be performed on firewater piping. Non-intrusive *follow-up* volumetric examinations *will be performed if internal visual inspections detect surface irregularities to determine if* ~~would detect loss of material due to corrosion, and would confirm~~ wall thickness is within acceptable limits ~~so that aging will be detected before the loss of intended function~~. Visual inspections ~~would~~ *will* evaluate *for the presence of sufficient foreign material to obstruct fire water pipe or sprinklers.* ~~(1) wall thickness as it applies to avoidance of catastrophic failure, and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system. The volumetric examination technique employed will be one that is generally accepted in the industry, such as ultrasonic or eddy current.~~

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

In response to draft LR-ISG-2013-01, the program includes visual inspections of Service Level III (augmented) internal coatings. For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the NRC associated with a particular standard.

The Fire Water program implements the recommendations in LR-ISG-2012-02, as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachments 7C and 8.

A1.15 Reactor Vessel Surveillance

The Reactor Vessel Surveillance program manages loss of fracture toughness due to neutron embrittlement in reactor materials exposed to neutron fluence exceeding $1.0E^{17}$ n/cm2 (E>1.0 MeV). The program is consistent with ASTM E 185-70 and ASTM E 185-73 for Units 1 and 2, respectively. Capsules are periodically removed during the course of plant operating life. Neutron embrittlement is evaluated through surveillance capsule testing and evaluation, ex-vessel neutron fluence calculations, and monitoring of reactor vessel neutron fluence. The testing program and reporting conform to requirements of 10 CFR 50 Appendix H, *Reactor Vessel Material Surveillance Program Requirements*. Data resulting from the program is used to:

- Determine pressure-temperature limits, minimum temperature requirements, and end-of-life Charpy upper-shelf energy (C_V USE) in accordance with the requirements of 10 CFR 50 Appendix G, *Fracture Toughness Requirements*; and,
- Determine end-of-life RT_{PTS} values in accordance with 10 CFR 50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock*.

The Reactor Vessel Surveillance program provides guidance for removal and testing or storage of material specimen capsules. *As discussed in PG&E Letter DCL-14-103, in order for PG&E to participate in the EPRI PWR Supplemental Surveillance Program, the donated specimens will no longer be stored.* All *other* capsules that have been withdrawn and tested were stored.

In order for PG&E to participate in the EPRI PWR Supplemental Surveillance Program, PG&E takes exception to NUREG-1801, Revision 1, Section XI.M31, Criterion 4, which states that pulled and tested capsules are placed in storage. Participation in the EPRI PWR Supplemental Program includes donation of up to seven Charpy V-Notch specimens (material Plate B5454-1) from the already tested DCPP Unit 2 Capsule V. The donated specimens will no longer be stored.

For Unit 1, the last capsule is expected to be withdrawn during the 1R23 refueling outage after it has accumulated a fluence equivalent to 94.2 years of operation. The remaining four standby capsules have low lead factors, will remain inside the vessel throughout the vessel lifetime, and will be available for future testing.

There are no capsules remaining in the Unit 2 vessel. All capsules were removed because high lead factors produced exposures comparable to the fluences expected at the end of the period of extended operation.

DCPP Units 1 and 2 currently use ex-vessel monitoring dosimetry, which consists of four gradient chains with activation foils outside the reactor vessel, which will be used to monitor the neutron fluence environment within the beltline region.

A1.16 ONE-TIME INSPECTION

The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (A1.2), Fire Water System program (A1.13), Fuel Oil Chemistry program (A1.14), and Lubricating Oil Analysis program (A1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. The One-Time Inspection program determines non-destructive examination *of a representative* sample size *of 20 percent of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components as discussed in DCL-14-103, Enclosure 1, Attachment 16.* ~~. for each material-environment group using an engineered sampling technique for each material-environment group~~ *This sample will be* based on criteria such as the longest service period, most severe operating conditions, lowest design margins, lowest or stagnant flow conditions, high flow conditions, and highest temperature. The One-Time Inspection program evaluates unacceptable inspection results using the corrective action program.

This new program will be implemented and completed during the 10-year period prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.18 BURIED PIPING AND TANKS INSPECTION

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

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

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

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended~~-of~~ operation. Inspections will be conducted during each 10-year period beginning 10 years prior to entering the period of extended operation. Examinations of buried piping ~~and tanks~~ will consist of visual inspections. *Significant indications of degradation observed during visual inspections of buried piping will require a supplemental surface and/or volumetric non-destructive testing.*~~as well as non-destructive examinations (e.g. ultrasonic examination capable of measuring wall thickness) to perform an overall assessment of the condition of buried piping and tanks~~.

The Buried Piping and Tanks Inspection program implements the recommendations in LR-ISG-2011-03 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3.

A1.20 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program manages loss of material for external surfaces of steel, stainless steel, aluminum, and copper alloy components, and hardening and loss of strength for elastomers. The program is a visual monitoring program that includes those systems and components within the scope of license renewal that require external surfaces monitoring.

Surfaces that are inaccessible or not readily visible during plant operations are inspected during refueling outages. Surfaces that are inaccessible or not readily visible during both plant operations and refueling will be evaluated by the DCPP Corrective Action Program to evaluate applicable industry and plant specific aging operating experience for the material and environment combination. The evaluation will determine if there is a representative location, based on the material, environment, and applicable aging effect that has been or can be inspected in place of the inaccessible components.

A sample of outdoor component surfaces that are insulated and indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are periodically inspected during the period of extended operation.

When appropriate for the component configuration and material, physical manipulation of elastomers is used to augment visual inspections to confirm absence of hardening or loss of strength for elastomers. Personnel performing external surfaces monitoring inspection will be qualified in accordance with site controlled procedures and processes.

The External Surfaces Monitoring Program is a new program that will be implemented *six months* prior to the period of extended operation. *The External Surfaces Monitoring program implements the recommendations in LR-ISG-2012-02, as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E.*

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

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

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

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

At a minimum, in each ten-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect), or a maximum of 25 components per population is inspected. Where practical, inspections focus on the bounding or lead components most susceptible to aging

because of time in service and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. Inspections (other than opportunistic inspections) will be based on assessments of the potential degradation which could lead to loss of intended function, and on current industry and plant-specific operating experience. Opportunistic inspections will be based on assessments of the potential degradation which could lead to loss of intended function, and on current industry and plant-specific operating experience.

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

In response to draft LR-ISG-2013-01, the program includes visual inspections of Service Level III (augmented) internal coatings. For coated surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). The test consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the NRC associated with a particular standard.

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

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented *six months* prior to the period of extended operation*, except for the volumetric tank inspections, which will begin ten years prior to the PEO in accordance with LR-ISG-2012-02, Appendix E, Table 4a*. *The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program implements the recommendations in LR-ISG-2012-02 and LR-ISG-2013-01, as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachments 7A, 7B, 7D, 7F, 7G, 7H, and 8.*

A1.41 PRESSURIZED WATER REACTOR VESSEL INTERNALS

The 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 the reactor vessel internals components. This program is consistent with LR-ISG-2011-04 as discussed in DCL-14-103, Enclosure 1, Attachment 4, and is used to manage: (a) cracking, including stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking, and cracking due to fatigue/cyclical loading; (b) loss of material induced by wear; (c) loss of fracture toughness due to either thermal aging embrittlement, 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 PWR Vessel Internals program is a new program that will be implemented prior to the period of extended operation.

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
3	Enhance the Fire Water System program: (a) Sprinkler heads in service for 50 years will be replaced or representative samples from one or more sample areas will be tested consistent with NFPA 25, *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, 2011 Edition* guidance. Test procedures will be repeated at 10-year intervals during the period of extended operation, for sprinkler heads that were not replaced prior to being in service for 50 years, to ensure that signs of degradation, such as corrosion, are detected prior to the loss of intended function, and (b) ~~For either periodic, non-intrusive volumetric examinations, or visual inspections on firewater piping. N~~*To perform n*on-intrusive *follow-up* volumetric examinations *if internal visual inspections detect surface irregularities to determine if* ~~would detect any loss of material due to corrosion to ensure that aging effects are managed,~~ wall thickness is within acceptable limits ~~and degradation would be detected before the loss of intended function~~. Visual inspections *will* ~~would~~ evaluate *for the presence of sufficient foreign material to obstruct fire water pipe or sprinklers* ~~(1) wall thickness as it applies to avoidance of catastrophic failure, and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system. The volumetric examination technique employed will be one that is generally accepted in the industry, such as ultrasonic or eddy current, and~~ (c) ~~To state trending requirements.~~ *To be in conformance with LR-ISG-2012-02, Section C as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7C.*	B2.1.13	~~Prior to the period of extended operation~~ *Program is implemented 5 years before the period of extended operation. Inspections of wetted normally dry piping segments that cannot be drained or that allow water to collect begin 5 years before the period of extended operation. The program's remaining inspections begin during the period of extended operation*

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
8	Implement the External Surfaces Monitoring Program as described in LRA Section B2.1.20 *and to be in conformance with LR-ISG-2012-02, Section E as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 7E*.	B2.1.20	*Six months* ~~P~~*p*rior to the period of extended operation.
9	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program as described in LRA Section B2.1.22 *and to be in conformance with LR-ISG-2012-02 and Draft LR-ISG-2013-01 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachments 7A, 7B, 7D, 7F, 7G, 7H, and 8 respectively.*	B2.1.22	*Six months p*rior to the period of extended operation
20	~~As additional Industry and applicable plant-specific operating experience become available, the operating experience will be evaluated and appropriately incorporated into the new programs through the DCPP Corrective Action and Operating Experience Programs. This ongoing review of operating experience will continue throughout the period of extended operation and the results will be maintained on site.~~ *DCPP procedures will be enhanced and implemented to conform to LR-ISG-2011-05, "Ongoing Review of Operating Experience," as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 5.*	~~B2.1.16~~ ~~B2.1.17~~ ~~B2.1.18~~ ~~B2.1.20~~ ~~B2.1.22~~ ~~B2.1.24~~ ~~B2.1.34~~ ~~B2.1.35~~ ~~B2.1.39~~ *A1*	~~Prior to the period of extended operation~~ *Upon receipt of the renewed operating licenses*
22	PG&E will: A. For Reactor Coolant System Nickel-Alloy Pressure Boundary Components: (1) Implement applicable NRC Orders, Bulletins and Generic Letters associated with nickel-alloys; (2) implement staff-accepted industry guidelines, (3) participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel-alloys, and (4) 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 coolant system nickel-alloy pressure boundary components to the NRC for review and approval~~, and~~. ~~B. For Reactor Vessel Internals:~~ ~~(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; (3) upon completion of these programs, but not less than~~	3.1 ~~4.3.3~~	Concurrent with industry initiatives and upon completion submit an inspection plan and not less than 24 months before entering the period of extended operation. ~~Information requested in the safety evaluation for MRP-227 will be~~

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
	~~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. 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; 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.~~		~~submitted 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.~~
32	DCPP plant procedures will be revised to perform concrete inspections per ASME Section XI Subsection IWL within a 5-year interval.	B2.1.28	~~Prior to the period of extended operation.~~*Complete*
~~48~~	~~DCPP will perform 100 percent eddy current testing of one nonregenerative heat exchanger as part of the One-Time Inspection Program within ten years prior to the period of extended operation.~~*Deleted in PG&E Letter DCL-14-103, Enclosure 1, Attachment 16.*	~~B2.1.16~~	~~During the 10 years prior to the period of extended operation.~~
52	The Buried Piping and Tanks Inspection Program will be revised to~~-~~ *conform to LR-ISG-2011-03 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3.* ~~-include the following inspections that will be conducted during each 10-year period beginning 10 years prior to the entry in the period of extended operation. Examinations of buried piping and tanks will consist of visual inspections as well as non-destructive examinations (e.g. ultrasonic examination capable of measuring wall thickness) to perform an overall assessment of the condition of buried piping and tanks.~~ ~~Each inspection will examine either the entire length of a run of pipe or a minimum of 10 feet. If the number of inspections times the minimum inspection length (10 feet) exceeds 10 percent of the length of the piping under consideration, only 10 percent will need to be inspected. If the total length of the in-scope pipe constructed of a given material times the percentage to be inspected is less than 10 feet, either 10 feet or the total length of pipe present, whichever is less will be inspected.~~ ~~Inspections of Buried Piping Based on Material and Environment Combinations~~	B2.1.18	Within 10 years prior to the period of extended operation

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
	Fire mains will be subject to a periodic flow test in accordance with NFPA 25 section 7.3 at a frequency of at least one test in each one year period. These flow tests will be performed in lieu of excavating buried portions of Fire Water pipe for visual inspections. ~~For cathodically-protected metallic piping, at least one excavation and visual inspection of steel piping will be conducted. Cathodically-protected steel piping within the scope of license renewal exists in the Auxiliary Salt Water (ASW) system intake lines.~~ ~~For non cathodically-protected buried metallic piping, at least four excavations and visual inspections of steel piping will be conducted. Non Cathodically-protected steel piping within the scope of license renewal exists in the ASW system discharge.~~ ~~For non metallic piping, at least one excavation and visual inspection each of polyvinyl chloride (PVC) and Asbestos Cement Pipe (ACP) will be conducted. PVC piping within the scope of license renewal exists in the Fire Water system. Asbestos cement piping within the scope of license renewal exists in the Fire Water system and Make-up Water system.~~		

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
64	PG&E will perform a regularly scheduled ISI ultrasonic inspection of WIC-95 during the upcoming 1R17 refueling outage, scheduled for May 2012, to confirm the absence of service-related flaw growth. Should service-related flaw growth be identified in this inspection, the corrective action program will be entered and appropriate corrective action will be taken in accordance with ASME Section XI Code. In absence of flaw growth, WIC-95 will continue to be inspected at a frequency required by the ISI Program Plan.	B2.1.1	~~Prior to the completion of 1R17~~*Complete*
66	PG&E will revise its plant procedure to include a 5.*1* percent allowance for predictability and a 10 percent allowance to account for instrument and wear scar uncertainty. This procedure will also be revised to include an 80 percent through wall acceptance criterion based upon its plant-specific FTT data wear and NRC acceptance of this 80 percent criterion. In conclusion, based on the WCAP-12866 80 percent acceptance criterion, including 5.*1* percent predictability uncertainty and 10 percent for eddy current testing instrument and wear scar uncertainty, PG&E will use a net acceptance criterion of ~~65~~ *64.9* percent. This procedure revision is currently scheduled to be completed prior to December 2011, but will be completed prior to the period of extended operation.	B2.1.21	Completed. PG&E Letter DCL-12-124. *Commitment modified and completed per PG&E Letter DCL-14-103.*
68	PG&E will revise its plant procedure to require the actual plant FTT specific wear data versus wear projections be evaluated every refueling outage to ensure it remains consistent with a maximum nonconservative wear projection of 5.*1* percent for wear above 40 percent. If the wear projection for a tube is determined to exceed the 5.*1* percent under-prediction and has over 40 percent wear the previous cycle, PG&E will enter it into the corrective action program for evaluation and disposition. This procedure revision is currently scheduled to be completed prior to December 2011, but will be completed prior to the period of extended operation.	B2.1.21	Completed. PG&E Letter DCL-12-124. *Commitment modified and completed per DCL-14-103.*
72	*Implement the PWR Vessel Internals Program to conform to LR-ISG-2011-04 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 4, including the plant-specific action items, conditions, and limitations identified in the NRC Safety Evaluation, Revision 1, for MRP-227.*	*B2.1.41*	*Prior to the period of extended operation*
73	*The NRC SE for MRP-227 contains eight action items for applicants/licensees to consider. Responses to the applicable aging management program 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. Reference DCL-14-103, Enclosure 1, Attachment 4.*	*B2.1.41*	*December 2015*

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
74	*PG&E will conform to Draft LR-ISG-2013-01 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 8.*	*B2.1.9* *B2.1.10* *B2.1.13* *B2.1.22*	*No later than six months before the period of extended operation and inspections begin no later than the last refueling outage before the period of extended operation*

One-Time Inspection

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-10-129, dated October 8, 2010
(4) PG&E Letter DCL-10-134, dated October 27, 2010
(5) PG&E Letter DCL-13-119, dated December 23, 2013

The NRC evaluated the DCPP One-Time Inspection program in its SER, Section 3.0.3.1.10, dated June 2, 2011.

The DCPP LRA was prepared to NUREG-1801, Revision 1. After the DCPP LRA was submitted, NUREG-1801, Revision 2, was issued, which incorporates additional operating experience. The NRC did not request any additional information that specifically referenced NUREG-1801, Revision 2, regarding DCPP's One-Time Inspection program.

SER Section 3.0.3.1.10 summarizes DCPP's current commitment for One-Time Inspection sampling size:

> "The applicant stated that it will conduct a ten percent inspection of the most susceptible locations (e.g., stagnant flow, low points) for each in-scope system to verify the effectiveness of (a) the Water Chemistry Program in managing loss of material, and cracking of stainless steel components exposed to an environment greater than 140°F, and (b) the Fuel Oil Chemistry Program in managing loss of material. The applicant also stated that it would inspect one heat exchanger per in-scope system that is (a) exposed to treated water and being managed by the Water Chemistry Program for fouling of heat exchanger tubes, and (b) exposed to lubricating oil and being managed by the Lubricating Oil Analysis Program for loss of material. The applicant further stated that it will perform a 100 percent eddy current test of stainless steel tubes in one of the nonregenerative heat exchangers."

PG&E is revising its licensing basis for the One-Time Inspection program to adopt the sample size for inspections recommended by Element 4, "Detection of Aging Effects" of AMP XI.M32, One-Time Inspection in NUREG-1801, Revision 2. The following describes the recommended sample size:

> For components managed by the AMP XI.M2, Water Chemistry"; AMP XI.M30, "Fuel Oil Chemistry"; and AMP XI.M39, "Lubricating Oil Analysis," programs, a representative sample size is 20 percent of the population (defined as

> components having the same material, environment, and aging effect combination) or a maximum of 25 components. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection should be included as part of the program's documentation.

This NUREG-1801, Revision 2, sample size will supersede the sample size previously described in PG&E's licensing basis where the One-Time Inspection program verifies the effectiveness of the DCPP Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis programs. Other portions of the program will remain as evaluated by the NRC in SER Section 3.0.3.1.10.

PG&E revises LRA Section A1.16 as shown in Attachment 15 to state that the One-Time Inspection program determines nondestructive examination of a representative sample size of 20 percent of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 25 components.

Because the revised sample size will be representative of all component types, including heat exchangers, PG&E deletes Table A4-1, Item 48, as shown in Attachment 15.

Reactor Vessel Surveillance Program

In order for PG&E to participate in the EPRI PWR Supplemental Surveillance Program, PG&E takes exception to NUREG-1801, Revision 1, Section XI.M31, Criterion 4, which states that pulled and tested capsules are placed in storage. Participation in the EPRI PWR Supplemental Program includes donation of up to seven Charpy V-Notch specimens (material Plate B5454-1) from the already tested DCPP Unit 2 Capsule V. The donated specimens will no longer be stored.

PG&E Letter DCL-09-079, Enclosure 1, Section B2.1.15 states that the Reactor Vessel Surveillance program provides guidance for removal and testing or storage of material specimen capsules. All capsules that have been withdrawn and tested were stored.

The NRC Staff evaluated the Reactor Vessel Surveillance program in its SER, Section 3.0.3.1.9, dated June 2, 2011. SER Section 3.0.3.1.9 (page 3-29) states:

> *"The applicant stated, in LRA Section B2.1.15, that the Reactor Vessel Surveillance Program provides guidance for removal and testing or storage of material specimen capsules, and it stored all capsules that have been withdrawn. The staff noted that a new license condition will require that all capsules placed in storage be maintained for future insertion, and any changes to storage requirements must be approved by the staff. Therefore, the Reactor Vessel Surveillance Program is consistent with GALL with respect to Criterion 4."*

NUREG-1801, Revision 2, Section XI.M31 recommends that all pulled and tested capsules with a neutron fluence greater than 50 percent of the projected reactor vessel neutron fluence at the end of the PEO are placed in storage (these specimens and capsules are saved for future reconstitution and reinsertion use). XI.M31 also states that if all surveillance capsules have been removed, alternative dosimetry may be used to monitor neutron fluence during the PEO.

DCPP has ample capsules remaining for future use since all of the Unit 2 capsules are in storage and are available for future use.

The Unit 2 capsules with the highest effective full power years are Capsules V, W, and Z. These capsules have a neutron fluence greater than 50 percent of the projected reactor vessel neutron fluence at the end of the PEO. DCPP FSAR Update, Table 5.2-22, Unit 2 Capsule V, was removed in refueling outage 9 (2R9) at 52.5 EFPY and tested. Unit 2 Capsules W and Z were also removed in 2R9 at 61.5 EFPY. All of these capsules are in storage.

FSAR Update Section 5.2.4.4.2, states that the six Unit 2 capsules contain a total of 180 Charpy V-Notch specimens (material Plate B5454-1). Unit 2 Capsule V contains a total of 30 Charpy V-Notch specimens (material Plate B5454-1). The EPRI PWR

Supplemental Surveillance Program requests use of up to seven of these from Capsule V, leaving twenty three other Unit 2 Capsule V subject specimens in storage for future use.

The DCPP Unit 2 reactor vessel surveillance program currently relies on monitoring of ex-vessel dosimetry (LRA Section B2.1.15; SER Section 3.0.3.1.9(7)) in lieu of in-vessel capsules.

Since the Unit 2 reactor vessel surveillance program can be successfully reestablished with the remaining available Capsule V specimens or use of any of the other five available capsules that are in storage, PG&E can participate in the EPRI PWR Supplemental Surveillance Program with a donation of up to seven Charpy V-Notch specimens (material Plate B5454-1).

In conclusion, PG&E takes exception to NUREG-1801, Revision 1, Section XI.M31, Criterion 4, which states that pulled and tested capsules are placed in storage (Note: These specimens are saved for future reconstitution use, in case the surveillance program is reestablished.). While all capsules that have been withdrawn and tested were stored, several Charpy V-Notch specimens from Unit 2 Capsule V have been donated to an industry research program. These donated specimens will no longer be available for future use at DCPP. If the Unit 2 surveillance program were to be reestablished, the remaining available Charpy V-Notch specimens within Unit 2 Capsule V could be used. Further, two other Unit 2 capsules of similar exposure are available to reestablish the surveillance program.

PG&E revises LRA Section A1.15 as shown in Attachment 15.

Acronym List

AMP	Aging Management Program
AMR	Aging management review
ASTM	American Society for Testing and Materials
ASW	Auxiliary saltwater
CAP	corrective action program
CCW	Component cooling water
CST	Condensate storage tank
DCPP	Diablo Canyon Power Plant
DFOST	Diesel fuel oil storage tank
ECG	equipment control guideline
EPRI	Electric Power Research Institute
FAC	Flow Accelerated Corrosion
FSAR	Final Safety Analysis Report
FWST	Fire water storage tank
GALL Report	Generic Aging Lessons Learned
LR-ISG	License Renewal – Interim Staff Guidance
LRA	License Renewal Application
MRP	Materials Reliability Program
MW	Makeup water
mV	milllivolt
NEI	Nuclear Energy Institute
NDT	Non-destructive testing
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
OCCW	Open-Cycle Cooling Water
OE	Operating experience
PEO	Period of extended operation
PG&E	Pacific Gas and Electric Company
ppb	Parts per billion
PVC	Poly-vinyl chloride
PWR	Pressurized water reactor
RCP	Reactor coolant pump
RIC	Recurring internal corrosion
RIS	Regulatory Issue Summary
RWSR	Raw water storage reservior
RWST	Refueling water storage tank
SE	Safety Evaluation
SER	Safety Evaluation Report
SRP	Standard Review Plan
SSC	Structure, system, or component
TLAA	Time-limited aging analysis

References

(1) PG&E Letter DCL-90-027, “Service Water System Problems Affecting Safety-Related Equipment,” dated January 26, 1990

(2) PG&E Letter DCL-91-286, “Supplemental Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment,” dated November 25, 1991

(3) PG&E Letter DCL-09-079, “License Renewal Application,” dated November 23, 2009

(4) PG&E Letter DCL-10-073, “Supplemental Response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment,” dated July 7, 2010

(5) PG&E Letter DCL-10-097, “Response to NRC Letter dated July 19, 2010, Request for Additional Information (Set 9) for the Diablo Canyon License Renewal Application,” dated August 2, 2010

(6) PG&E Letter DCL-10-105, “Response to NRC Letter dated July 22, 2010, Request for Additional Information (Set 15) for the Diablo Canyon License Renewal Application,” dated August 18, 2010

(7) PG&E Letter DCL-10-113, “Response to NRC Letter dated August 3, 2010, Request for Additional Information (Set 16) for the Diablo Canyon License Renewal Application,” dated August 26, 2010

(8) PG&E Letter DCL-10-122, “Response to NRC Letter dated August 26, 2010, Request for Additional Information (Set 20) for the Diablo Canyon License Renewal Application and LRA Errata,” dated September 22, 2010

(9) PG&E Letter DCL-10-123, “Response to NRC Letter dated August 30, 2010, Request for Additional Information (Set 21) for the Diablo Canyon License Renewal Application,” dated September 29, 2010

(10) PG&E Letter DCL-10-129, “Response to NRC Letter dated September 15, 2010, Summary of Telephone Conference Call Held on August 18, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application,” dated October 8, 2010

(11) PG&E Letter DCL-10-130, "Response to NRC Letter dated September 17, 2010, Request for Additional Information (Set 24) for the Diablo Canyon License Renewal Application," dated October 12, 2010

(12) PG&E Letter DCL-10-134, "Response to NRC Letter dated September 28, 2010, Summary of Telephone Conference Call Held on September 2, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated October 27, 2010

(13) PG&E Letter DCL-10-147, "Response to Draft Requests for Additional Information (Sets 31 & 33) for the Diablo Canyon License Renewal Application," dated November 24, 2010

(14) PG&E Letter DCL-10-148, "Response to NRC Letter dated November 03, 2010, Request for Additional Information (Set 29) for the Diablo Canyon License Renewal Application, dated November 24, 2010

(15) PG&E Letter DCL-10-151, "Response to Telephone Conference Call Held on November 9, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated November 24, 2010

(16) PG&E Letter DCL-11-002, "Response to Telephone Conference Call Held on December 9, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated January 21, 2011

(17) PG&E Letter DCL-11-022, "Pacific Gas and Electric Company Supplements a Response to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated March 14, 2011

(18) PG&E Letter DCL-11-037, "Response to Telephone Conference Calls Held on February 2 and 4, 2011, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated March 25, 2011

(19) 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

(20) PG&E Letter DCL-12-089, "Inservice Inspection Report for Unit 1 Seventeenth Refueling Outage," dated September 13, 2012

(21) PG&E Letter DCL-12-124, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application and License Renewal Application Amendment Number 46," dated December 20, 2012

(22) PG&E Letter DCL-13-119, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application and License Renewal Application Amendment Number 47," dated December 23, 2013

Affected LRA Appendix E Sections, Tables, Figures, and Appendices

The following LRA Appendix E sections, tables, figures, and appendices were updated to provide information necessary to complete the NRC environmental review, as requested in the letter dated July 3, 2014, "Summary of June 5, 2014, Conference Call to Discuss the Status of the License Renewal Application Review of the Diablo Canyon Nuclear Power Plant, Units 1 and 2." LRA Appendix E, Chapter 7, "Alternatives to the Proposed Action," Chapter 8, "Comparison of Environmental Impacts of License Renewal With the Alternatives," Section 9.2, "Alternatives", and Attachment F, "Severe Accident Mitigation Alternatives," are currently scheduled to be submitted to the NRC in February 2015.

ER Reference	Subject
Section 1.2	Environmental Report Scope and Methodology
Section 1.4	References
Table 1.2-1	Environmental Report Responses to License Renewal Environmental Regulatory Requirements
Section 2.1	Location and Features
Section 2.2	Aquatic Ecology
Section 2.3	Groundwater Resources
Section 2.4	Important Terrestrial Habitats
Section 2.5	Threatened or Endangered Species
Section 2.6	Demography
Section 2.7	Taxes
Section 2.8	Land Use Planning
Section 2.9	Social Services and Public Facilities
Section 2.10	Meteorology and Air Quality
Section 2.11	Historic and Archaeological Resources
Section 2.12	Known or Reasonably Foreseeable Projects in the Site Vicinity
Section 2.13	Geology and Soils (previously References)
Section 2.14	References
Table 2.2-1	Phylogenic Listing of Intertidal (I) and Subtidal (S) Marine Organisms Associated with the DCPP Coastline
Table 2.2-3	Aquatic Special Status Species with the Potential to Occur Off the Diablo Canyon Lands
Table 2.4-1	Terrestrial Special Status Species with the Potential to Occur On the Diablo Canyon Lands
Table 2.5-1	List of Federally Threatened or Endangered Species that may Occur on the DCPP Site or Immediately Offshore
Table 2.6-1	Population Trends of the State of California and of San Luis Obispo and Santa Barbara Counties
Table 2.6-2	Minority and Low Income Population Information
Table 2.7-1	Property Tax Breakdown for 2004-2014
Table 2.8-1	Housing Statistics for San Luis Obispo and Santa Barbara Counties

ER Reference	Subject
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Table 2.9-3	San Luis Obispo County School District Statistics
Table 2.10-1	Attainment Status of SLO County, All Monitoring Stations
Figure 2.3-1	Onsite Monitoring Well Locations
Figure 2.5-2	Black Abalone Decline
Figure 2.6-1	Aggregate Minority Populations
Figure 2.6-2	Hispanic Minority Populations
Figure 2.6-3	Low-Income Populations
Figure 2.6-4	Other Minority Populations
Figure 2.6-5	Black/African American Minority Populations
Figure 2.8-1	Land-Use Map
Figure 2.13-1	Geomorphic Regions in the DCPP Vicinity
Figure 2.13-2	Geologic Units in the DCPP Vicinity
Figure 2.13-3	Faults in the DCPP Vicinity
Section 3.1	General Plant Information
Section 3.2	Refurbishment Activities
Section 3.4	Employment
Section 3.5	References
Figure 3.1-1	Site Layout
Section 4.0	Discussion of Updated GEIS License Renewal Categories
Section 4.2	Entrainment of Fish and Shellfish in Early Life Stages
Section 4.3	Impingement of Fish and Shellfish
Section 4.4	Heat Shock
Section 4.5	Groundwater Use Conflicts (Plants Using <100 GPM of Groundwater)
Section 4.10	Threatened or Endangered Species
Section 4.11	Air Quality During Refurbishment (Non-Attainment Areas)
Section 4.17	Offsite Land Use
Section 4.18	Transportation
Section 4.21	Environmental Justice
Section 4.22	References
Chapter 5	Assessment of New and Significant Information
Section 5.1	References
Section 6.1	License Renewal Impacts
Section 6.2	Mitigation
Section 6.3	Unavoidable Adverse Impacts
Section 6.4	Irreversible and Irretrievable Resource Commitments
Section 6.6	References
Table 6-1	Category 2 Environmental Impacts related to License Renewal at DCPP
Chapter 7	Alternatives to the Proposed Action (currently scheduled to be submitted in February 2015)

ER Reference	Subject
Chapter 8	Comparison of Environmental Impacts of License Renewal With the Alternatives (currently scheduled to be submitted in February 2015)
Section 9.1	Proposed Action
Section 9.2	Alternatives (currently scheduled to be submitted in February 2015)
Table 9-1	Environmental Authorizations for Current DCPP Operations
Table 9-2	Environmental Authorizations for DCPP License Renewal
Attachment A	NRC NEPA Issues for License Renewal of Nuclear Power Plants
Table A-2	DCPP Environmental Report Cross-Reference of New License Renewal NEPA Issues Identified in the Revised GEIS
Attachment E	CZMA Consistency Certification
Attachment F	Severe Accident Mitigation Alternatives (currently scheduled to be submitted in February 2015)