UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

February 2, 2016

Mr. Edward D. Halpin
Senior Vice President and Chief
Nuclear Officer
Pacific Gas and Electric Company
P.O. Box 56, Mail Code 104/6
Avila Beach, CA 93424

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DIABLO CANYON POWER PLANT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 39 (TAC NOS. ME2896 AND ME2897)

Dear Mr. Halpin:

By letter dated November 23, 2009, Pacific Gas & Electric Company (PG&E) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew the operating licenses DPR-80 and DPR-82 for Diablo Canyon Power Plant, Units 1 and 2, respectively. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information were discussed with Mr. Terry Grebel, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me at 301-415-1427 or by e-mail at richard.plasse@nrc.gov.

Sincerely,

/RA/

Richard Plasse, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-275 and 50-323

Enclosure:
As stated

cc: Listserv

February 2, 2016

Mr. Edward D. Halpin
Senior Vice President and Chief
Nuclear Officer
Pacific Gas and Electric Company
P.O. Box 56, Mail Code 104/6
Avila Beach, CA 93424

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DIABLO CANYON POWER PLANT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 39 (TAC NOS. ME2896 AND ME2897)

Dear Mr. Halpin:

By letter dated November 23, 2009, Pacific Gas & Electric Company (PG&E) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew the operating licenses DPR-80 and DPR-82 for Diablo Canyon Power Plant, Units 1 and 2, respectively. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information were discussed with Mr. Terry Grebel, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me at 301-415-1427 or by e-mail at richard.plasse@nrc.gov.

Sincerely,

/RA/

Richard Plasse, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-275 and 50-323

Enclosure: As stated

cc: Listserv

DISTRIBUTION:
See next page
ADAMS Accession No.: **ML16011A365**
Document Name: Draft RAI Set 39 Annual Update Questions.doc
☑ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☑ Non-Sensitive

To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl, "E" = Copy with attach/encl, "N" = No copy

OFFICE	LA:DLR	PM:RPB1:DLR	BC:RPB1:DLR	PM:RPB1:DLR
NAME	YEdmonds	RPlasse	YDiaz-Sanabria	RPlasse
DATE	1/ 14 /16	1/ 14 /16	2/ 1 /16	2/ 2 /16

OFFICIAL RECORD COPY

Letter to E. Halpin from R. Plasse dated February 2, 2016

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DIABLO CANYON POWER PLANT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 39 (TAC NOS. ME2896 AND ME2897)

DISTRIBUTION:

HARD COPY:
DLR RF

E-MAIL:
PUBLIC
RidsNrrDlr Resource
RidsNrrDlrRpb1 Resource
RidsNrrDlrRpb2 Resource
RidsNrrDlrRerb Resource
RidsNrrDlrRarb Resource
RidsNrrDlrRasb Resource
RidsNrrDlrRsrg Resource
RidsOgcMailCenter Resource
RidsNrrPMDiabloCanyon Resource

R. Plasse
M. Wentzel
J. Danna
S. Lingam
S. Uttal, OGC
J. Lindell, OGC
E. Williamson, OGC
T. Hipschman, SRI
J. Reynoso, RI
G. Miller, RIV
W. Walker, RIV
W. Maier, RIV
D. McIntyre, OPA
V. Dricks, OPA
A. Moreno, OCA
R. Rihm, EDO

LICENSE RENEWAL APPLICATION
DIABLO CANYON POWER PLANT, UNITS 1 AND 2

REQUESTS FOR ADDITIONAL INFORMATION – SET 39
(TAC NOS. ME2896 AND ME2897)

RAI 2.1-4

Background:

10 CFR 54.4, “Scope,” states, in part:

(a) Plant systems, structures and components within the scope of this part are –

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions –

(i) The integrity of the reactor coolant pressure boundary;
(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11 of this chapter, as applicable.

(2) All nonsafety-related systems, structures and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

Issue:

The staff reviewed the applicant’s, December 22, 2014, letter that provided an update to the Diablo Canyon License Renewal Application (LRA). Attachment 9 of the letter, “Updates to Reflect Installed Plant Equipment and Editorial Corrections,” stated that the methodology contained in LRA Section 2.1.2.2, “Title 10 CFR 54.4(a)(2) – Nonsafety-Related Affecting Safety Related,” had been modified.

LRA Section 2.1.2.2, described the method used to identify nonsafety-related systems, structures, and components (SSCs), having the potential for spatial interaction with safety-related SSCs that could impact the ability of the safety-related SSCs to perform their intended functions, for inclusion within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). LRA Section 2.1.2.2 originally stated:

> 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).

ENCLOSURE

Attachment 9 modified LRA Section 2.1.2.2 as follows (italics added):

> 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*.

<u>Request</u>:

The staff requests the applicant to provide the following:

1. Describe the component specific engineering evaluation process used to remove nonsafety-related SSCs from the scope of license renewal, which were originally documented in the LRA as being included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2)
2. List the nonsafety-related SSCs for which component specific engineering evaluations were performed.
3. List the nonsafety-related SSCs for which the component specific engineering evaluations resulted in a different conclusion than that originally documented in the LRA, as to whether the SSC was within or not within the scope of license renewal, and describe those conclusions.

RAI B2.1.13-5a

<u>Background</u>:

By letter dated October 21, 2015, PG&E responded to RAI B2.1.13-5 by discussing corrective actions taken in the Fire Water System program for past occurrences of recurring internal corrosion (RIC). These actions included the development of long-term plans for monitoring and replacement of corroded piping with new corrosion-resistant piping and the use of high quality reverse osmosis water in the fire water system with chemistry controls to mitigate against corrosion starting in 2008. With respect to RIC, PG&E stated that augmented inspections are not necessary because follow-up inspections conducted since implementation of the corrective actions demonstrate the adequacy of the corrective actions.

<u>Issue</u>:

The RAI asked that a discussion be included about the trend for internal corrosion occurrences in the fire protection system to show that the program adequately manages recurring aging effects. However, the response did not provide any trend information to demonstrate the adequacy of the corrective actions or identify the corrosion mechanism resulting in RIC. If the trend for internal corrosion occurrences has not decreased or the follow-up inspections were not conducted on piping prone to RIC (e.g., conducting follow-up inspections on random locations when the corrosion mechanism resulting in RIC does not affect the system uniformly), then it is unclear to the staff how the adequacy of the past corrective actions has been demonstrated, and whether augmented inspections are necessary.

Request:

Identify the corrosion mechanism resulting in RIC and describe the follow-up inspections that have been conducted since the implementation of corrective actions to demonstrate the adequacy of the corrective actions. Include trend data for internal corrosion occurrences in the fire water system to show that the program adequately manages recurring aging effects. If the trend for internal corrosion occurrences in the fire water system is not decreasing, then provide justification why augmented inspections are not warranted to address recurring internal corrosion.

RAI B2.1.15-3

Background:

Attachment 17 of the applicant's 2014 annual update (December 22, 2014) states that 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. Unit 2 Capsule V was removed in refueling outage 9 (2R9) at 52.5 effective full power years (EFPY) and tested. Unit 2 Capsules W and Z were also removed in 2R9 at 61.5 EFPY. All these capsules are in storage.

Generic Aging Lessons Learned (GALL) Report, Rev. 2, aging management program (AMP) XI.M31 "Reactor Vessel Surveillance," states that the plant-specific or integrated surveillance program shall have at least one capsule with a projected neutron fluence equal to or exceeding the 60-year peak reactor vessel wall neutron fluence prior to the end of the period of extended operation. The GALL Report also states that the program withdraws one capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation and tests the capsule in accordance with the requirements of ASTM E 185-82.

Issue:

The staff noted that UFSAR Table 5.2-22, "Reactor Vessel Material Surveillance Program Withdrawal Schedule," states that Capsules W and Z for Unit 2 were removed during refueling outage 9. It is unclear to the staff whether or not one of the 61.5 EFPY capsules (either Capsule W or Z) will be tested in accordance with the requirements of ASTM E 185-82.

Request:

State whether or not one of the 61.5 EFPY capsules (either Capsule W or Z) will be tested in accordance with the requirements of ASTM E 185-82, for the purpose of license renewal. If not, justify why neither capsule will be tested.

RAI B2.1.18-4a

Background:

The response to RAI B2.1.18-4, dated October 21, 2015, states an alternative to qualification of individuals responsible for determining the type and extent of coating degradation for buried piping to NACE (formerly known as the National Association of Corrosion Engineers) or Electric Power Research Institute (EPRI) qualifications. The alternative is to use inspectors qualified to ASTM D4537, "Standard Guide for Establishing Procedures to Qualify and Certify Personnel Performing Coating and Lining Work Inspection in Nuclear Facilities."

Issue:

The staff noted that ASTM D4537 is endorsed by RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends that a coating specialist be used to assess degraded coatings.

Request:

State the basis for using an individual qualified to conduct inspections to assess the type and extent of coating degradation.

RAI B2.1.18-5a

Background:

The response to RAI B2.1.18-5, dated October 21, 2015, states:

> As stated in PG&E Letter DCL-14-1 03, Enclosure 1, Attachment 3, item 11, the buried piping encased in concrete for which PG&E states no aging effect requiring management is the ASW discharge piping. There is reasonable assurance that the exterior surface of the buried ASW piping encased in concrete will continue to perform its intended function during the period of extended operation consistent with the current licensing basis because the piping is encased in structural concrete. The ASW piping encased in concrete meets American Concrete Institute (ACI) 318. Cracking of this concrete is controlled through proper arrangement and distribution of reinforcing steel and is constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI. In addition, the ASW discharge piping is located approximately 57 feet above the anticipated high ground water elevation.

Issue:

Although the concrete, consistent with the GALL Report, meets ACI 318 and the pipe is well above the anticipated high ground water elevation, the piping is buried in soil that is exposed to rainwater. LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks'," recommends that the top surfaces and at least 50 percent of the side surface of concrete (in soil) surrounding piping be visually inspected for cracks in the concrete that could admit groundwater to the external surfaces of the piping.

Request:

State the basis for why inspections are not proposed to verify that cracking is not occurring in the concrete surrounding buried piping encased in concrete.

RAI 3.0.3.2.6-2a

Background:

The response to RAI 3.0.3.2.6-2, dated October 21, 2015, states that for fire water storage tanks, "[i]f adverse wall thickness trends are identified during routine inspections such that minimum wall thickness is projected to be reached prior to the next scheduled inspection (currently every 5 years), then the tank will be drained down, the 6 tests specified in NFPA-25, Section 9.2.7 will be performed, corroded base metal will be restored, and degraded coatings will be repaired."

Issue:

The lack of adverse wall thickness measurements is not a sufficient basis to conclude that the coating tests cited in NFPA 25 Section 9.2.7 are not required. Degraded coatings in and of themselves can cause a loss of intended function due to downstream flow blockage.

Request:

State the basis for why the lack of adverse wall thickness measurements is a sufficient criterion to conclude that degraded coating testing may not be required.

RAI 3.4.2.3.1-1a

Background:

As amended by letter dated October 21, 2015, LRA Table 3.4.2-1 states that internally coated/lined carbon steel piping, valves, and tanks exposed to demineralized water may be temporarily exposed to sulfuric acid in the steam generator blowdown treatment demineralizer system. The letter states that the sulfuric acid concentration would be between 4 and 96 percent, flowing up to a rate of 24.5 gallons per minute at ambient temperature. The linings used in the system are polypropylene, ethylene, fluorinated ethylene propylene, and semi-hard rubber.

ASM Handbook, Volume 13C, states that polyethylene is compatible with sulfuric acid up to 98 percent concentration at ambient temperature for short durations of service, that fluorinated ethylene propylene is compatible with all concentrations of sulfuric acid up to 205 °C, and that polypropylene is used in linings for pipe that handles sulfuric acid. ASM Handbook, Volume 13C, did not provide information on the compatibility of semi-hard rubber and sulfuric acid.

Corrosion Resistant Linings and Coatings by Philip A. Schweitzer (2001) states that semi-hard natural rubber is compatible with sulfuric acid at 10 percent concentration up to 82 °C, compatible with sulfuric acid at 50 percent concentration up to 38 °C, and incompatible with sulfuric acid at concentrations of 70, 90, and 98 percent.

As amended by letter dated October 21, 2015, internally coated/lined carbon steel components in the steam generator blowdown treatment demineralizer system were evaluated and determined to meet the six alternative inspection criteria of LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Lining on In-Scope Piping, Piping Components, Heat Exchangers and Tanks," and will now be managed using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program. The fourth alternative inspection criteria listed in LR-ISG-2013-01 states "[t]he internal environment would not promote microbiologically-influenced corrosion (MIC) of the base metal."

EPRI Report 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," Revision 4, states "[a]lthough MIC is not probable in treated water systems it cannot be categorically excluded due to the potential for contamination and subsequent damage if left untreated."

Issue:

1. Although components in the steam generator blowdown treatment demineralizer system would only be exposed to sulfuric acid in the event of a steam generator tube rupture or significant steam generator tube leak, lining systems should be compatible with sulfuric acid at the specified operating conditions for short durations of service. The staff has reviewed ASM Handbook, Volume 13, and has concluded that polypropylene, polyethylene, and fluorinated ethylene propylene linings would be compatible with sulfuric acid at the specified operating conditions.

   The staff could not determine if the use of the term 'ethylene' in letter dated October 21, 2015, refers to polyethylene and could therefore not determine if this lining is adequate for the sulfuric acid operational environment. Furthermore, the staff could not determine whether semi-hard rubber would be compatible with the sulfuric acid operational environment based on review of the ASM Handbook and Corrosion Resistant Linings and Coatings by Philip A. Schweitzer (2001).

2. The staff notes that MIC is not addressed in GALL Report, Revision 2, for carbon steel exposed to treated water. However, the staff has concluded that MIC is an applicable aging effect for carbon steel exposed to treated water. It is unclear to the staff why MIC is not an applicable aging effect for this material/environment combination.

Request:

1. State whether the use of the term ethylene in letter dated October 21, 2015 refers to polyethylene. If not, justify why the Internal Surfaces in Miscellaneous Piping and Ducting Components program is adequate such that the intended function of ethylene lined carbon steel piping, valves, and tanks exposed to sulfuric acid for short durations will be maintained.

   Justify why the Internal Surfaces in Miscellaneous Piping and Ducting Components program is adequate such that the intended function of semi-hard rubber lined carbon steel piping, valves, and tanks exposed to sulfuric acid for short durations will be maintained.

2. In order to determine if the six alternative inspection criteria of LR-ISG-2013-01 are met, state the basis for why MIC is not an applicable aging effect for carbon steel exposed to demineralized water in the Turbine Steam Supply System.

RAI 3.4.2.3.1-3a

Background:

By letter dated September 24, 2015, RAI 3.4.2.3.1-3 requested further information on coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply (LRA Table 3.4.2-1) and condensate systems (LRA Table 3.4.2-4).

Issue:

By letter dated October 21, 2015, the response to RAI 3.4.2.3.1-3 does not address coated/lined carbon steel demineralizers exposed to secondary water in the condensate system (LRA Table 3.4.2-4).

Request:

Explain why coated/lined carbon steel demineralizers exposed to secondary water in the condensate system (LRA Table 3.4.2-4) are not addressed in the response to RAI 3.4.2.3.1-3.

RAI 4.2.1-2

Background:

Attachment 2 of the applicants 2011 annual update (December 21, 2011) indicates that for both units, the nozzle shell course and the associated nozzle shell to intermediate shell weld are projected to exceed the $1x10^{17}$ n/cm^2 threshold. The applicant also stated, however, that the nozzles themselves as well as the nozzle to nozzle shell welds remain below the $1x10^{17}$ n/cm^2 threshold through 54 effective full-power year (EFPY).

Issue:

It is not clear to the staff why the nozzle shell course and the associated nozzle shell to intermediate shell weld are projected to exceed $1x10^{17}$ n/cm^2 while the nozzles themselves, the nozzle to nozzle shell welds, and the lower shell to lower head weld remain below the $1x10^{17}$ n/cm^2 threshold through 54 EFPY.

Request:

Identify the specific nozzles and nozzle-to-nozzle weld components that are being referred to in the above statement and identify what the inside surface neutron fluences are for these components, as projected to 54 EFPY. If any of the neutron fluences for these components are projected to exceed a value of $1x10^{17}$ n/cm^2 (E > 1.0 MeV) at 54 EFPY, provide the associated pressurized thermal shock (PTS) and upper shelf energy (USE) calculations for the components at 54 EFPY.