UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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November 17, 2010

John T. Conway
Senior Vice President-Energy &
Supply and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Nuclear Plant
77 Beale Street, Mail Code B32
San Francisco, CA 94105

SUBJECT: DIABLO CANYON POWER PLANT - NRC LICENSE RENEWAL INSPECTION REPORT 05000275/2010008 AND 05000323/2010008

Dear Mr. Conway:

On September 16, 2010, a U.S. Nuclear Regulatory Commission (NRC) team completed the onsite portion of an inspection of your application for license renewal of your Diablo Canyon Power Plant. The team discussed the inspection results with Mr. L. Sharp, Engineering Services Senior Director, and other members of your staff.

This inspection examined activities that supported the application for a renewed license for the Diablo Canyon Power Plant. The inspection addressed your processes for scoping and screening structures, systems, and components to select equipment subject to an aging management review. Further, the inspection addressed the development and implementation of aging management programs to support continued plant operation into the period of extended operation. As part of the inspection, the NRC examined procedures and representative records, interviewed personnel, and visually examined accessible portions of various structures, systems, or components to verify license renewal boundaries and to observe any effects of equipment aging. The visual examination of structures, systems, and components also included some areas not normally accessible, which included the diesel fuel oil vaults. These NRC inspection activities constitute one of several inputs into the NRC review process for license renewal applications.

The team concluded that your staff appropriately implemented the screening and scoping of nonsafety-related structures, systems, and components that could affect safety-related structures, systems and components. The team concluded that your staff conducted an appropriate review of the materials and environments and established appropriate aging management programs, as described in the license renewal application and as supplemented through your responses to requests for additional information from the NRC. The team concluded that your staff maintained the documentation supporting the application in an auditable and retrievable form. The team identified a number of issues that resulted in your staff supplementing or amending the application, programs, and procedures.

Based on the samples reviewed by the team, the inspection results support a conclusion of reasonable assurance that actions have been identified and have been or will be taken to manage the effects of aging in the structures, systems, and components identified in your application and that the intended functions of these structures, systems, and components will be maintained in the period of extended operation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Neil O'Keefe, Chief
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Division of Reactor Safety

Dockets: 50-275; 50-323
Licenses: DPR-80; DPR-82

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	05000275, 05000323
Licenses:	DPR-80, DPR-82
Report:	05000275/2010008, 05000323/2010008
Applicant:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	August 16 through September 16, 2010
Inspectors:	G. Pick, Senior Reactor Inspector L. Carson, Senior Reactor Inspector G. Meyer, Senior Reactor Inspector J. Watkins, Reactor Inspector J. Melfi, Reactor Engineer A. Erickson, Reactor Inspector
Approved By:	Neil O'Keefe, Chief Engineering Branch 2 Division of Reactor Safety

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2010008, 05000323/2010008; 08/16/2010 – 09/16/2010; Diablo Canyon Power Plant, Scoping of Nonsafety-Related Affecting Safety-Related Systems and Review of License Renewal Aging Management Programs

NRC inspectors from Region IV and Region I performed onsite inspections of the applicant's license renewal activities. The team performed the evaluations in accordance with Manual Chapter 2516, "Policy and Guidance for the License Renewal Inspection Programs," and Inspection Procedure 71002, "License Renewal Inspection." The team did not identify any findings as defined in NRC Manual Chapter 0612.

The team concluded the applicant adequately performed screening and scoping of nonsafety-related structures, systems, and components as required in 10 CFR 54.4(a)(2). The team concluded that the applicant conducted an appropriate review of the materials and environments and established appropriate aging management programs, as described in the license renewal application and as supplemented through responses to requests for additional information from the NRC. The team found that the applicant provided the documentation that supported the application and inspection process in an auditable and retrievable form. The team identified a number of issues that resulted in changes to the application, programs, and procedures.

Based on the samples reviewed by the team, the inspection results supported a conclusion of reasonable assurance that actions have been identified and have been taken or planned to manage the effects of aging in the structures, systems, and components identified in the application and that the intended functions of these structures, systems, and components would be maintained in the period of extended operation.

A. <u>NRC-Identified and Self-Revealing Findings</u>

No findings of significance were identified

B. <u>Licensee-Identified Violations</u>

No findings of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA5 Other - License Renewal

a. Inspection Scope (IP 71002)

NRC inspectors performed this inspection to evaluate the thoroughness and accuracy of the applicant's screening and scoping of nonsafety-related structures, systems, and components (SSC), as required in 10 CFR 54.4(a)(2). The team evaluated whether aging management programs will be capable of managing identified aging effects in an appropriate manner.

In order to evaluate scoping activities, the team selected a number of SSCs for review to evaluate whether the methodology used by the applicant appropriately addressed the nonsafety-related systems affecting the safety functions of a structure, system, or component within the scope of license renewal. In addition, because of several requests for additional information related to scoping of nonsafety-related systems affecting safety-related systems, the team conducted walkdowns to verify information in the responses provided by the applicant.

The team selected a sample of 24 of the 40 aging management programs developed by the applicant to verify the adequacy of the applicant's guidance, implementation activities, and documentation. The team evaluated the programs to determine whether the applicant would appropriately manage the effects of aging and to verify that the applicant would maintain the component safety functions during the period of extended operation.

The team reviewed supporting documentation and interviewed applicant personnel to confirm the accuracy of the license renewal application conclusions. For a sample of plant structures and systems, the team walked down accessible portions of the systems to observe aging effects. During the plant walkdowns, the team reviewed the material condition of the SSCs.

b.1 Evaluation of Scoping of Nonsafety-Related Structures, Systems, and Components

For scoping and screening, the team reviewed the applicant's program guidance and scoping and screening results for the facility to assess the thoroughness and accuracy of the methods used to bring SSCs within the scope of the license renewal application. Further, the team assessed documentation related to scoping nonsafety-related SSCs, as required in 10 CFR 54.4(a)(2). The team verified that the applicant established procedures consistent with the NRC-endorsed guidance contained in Nuclear Energy Institute 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 6, Appendix F, Sections 3, 4, and 5. The team assessed whether the applicant evaluated (1) nonsafety-related SSCs within the scope of the current licensing basis, (2) nonsafety-related SSCs directly connected to safety-related SSCs, and (3) nonsafety-related SSCs not directly connected but spatially near safety-related SSCs, respectively.

The team reviewed license renewal drawings, sampling between Units 1 and 2. The applicant had color-coded the drawings to indicate in-scope systems and components required by 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The team interviewed personnel, reviewed program documents and independently walked down numerous areas and structures within the plant, which included:

- Units 1 and 2 auxiliary buildings
- Units 1 and 2 turbine building
- Diesel generator rooms 1-3, 2-1, and 2-3
- Units 1 and 2 closed cooling water heat exchanger rooms
- Intake structure
- Oily waste sump room
- Unit 1 diesel generator fuel oil storage vault
- Discharge structure
- Raw water ponds
- 230 kV and 500 kV switchyards

For SSCs selected because of potential spatial interactions, where failure of nonsafety-related SSCs could adversely affect adjacent safety-related components, the team determined that the applicant continued to submit changes to their license renewal application to accurately categorize the in-plant configuration in response to requests for additional information. The team determined the personnel involved in the process were knowledgeable and appropriately trained.

For SSCs selected because of potential structural interactions caused by an earthquake, the team determined that the applicant accurately identified and categorized the structural boundaries. Based on independent sampling of the isometric drawings and the seismic boundary determinations, the team determined that the applicant appropriately identified the seismic design boundaries and correctly included the applicable SSCs within the license renewal scope.

Subsequent to the application submittal, the applicant added portions of additional systems to those already in scope based on lessons learned from another applicant and deficiencies identified during the Division of License Renewal scoping and screening audit. Specifically, the applicant determined that they had not adequately evaluated situations where age-related failures of systems in the turbine building could have affected nearby safety-related cables.

The team evaluated the plant configurations for SSCs that had been added since the scoping and screening audit conducted in March 2010. Specifically, the team conducted interviews, reviewed walkdown reports, and walked down configurations of SSCs in the plant to evaluate the impact of nonsafety-related SSCs affecting safety-related SSCs in the turbine building, terminations points in the compressed air system, the configuration of the oily waste sump, and the configuration of SSCs in the diesel generator fuel oil vaults. Specifically, the team:

- Verified that nonsafety-related service cooling water piping entered and exited the Diesel Generator 2-3 room and did not enter the other diesel generator rooms.

- Verified that no safety-related electric cables entered the oily waste sump room by reviewing plant drawings and walking down the oily waste sump.

- Verified that water spray from the service cooling water surge tank would not have affected the safety-related control room pressurization system components. Further, the team determined that control room pressurization electrical and instrumentation system components would not be affected.

- Verified that the applicant evaluated the impact of high-energy fluid piping failures on in-scope safety-related components in the turbine building.

- Verified that the applicant identified nonsafety-related components that could impact Class II components required to respond to a seismic event.

The applicant issued Notification 50341848 to document that they had not included the service cooling water surge tank as a component within the scope of license renewal. The team determined the applicant planned to revise Topical Report TR-6DC, "Criterion (a)(2) - License Renewal Feasibility Study Position Paper," Revision 1. The revised topical report would describe their basis for excluding the service water system surge tank since the tank would not impact the control room pressurization system. The team considered this an appropriate resolution after verifying that the water spray would not affect the control room pressurization system components.

In summary, the team concluded that the applicant had implemented an acceptable method of scoping of nonsafety-related SSCs and that this method resulted in accurate scoping determinations for the samples reviewed with some exceptions noted.

b.2 Evaluation of New Aging Management Programs

The team reviewed six of the nine new aging management programs to determine whether the applicant had established appropriate actions or had actions planned to manage the effects of aging. At the time of the inspection, the applicant had completed many of the elements identified in the programs, including drafting implementing procedures. The team reviewed site-specific operating experience to determine whether there were any aging effects for the systems and components within the scope of these programs that had not been identified when considering applicable industry operating experience.

The team selected in-scope SSCs to assess how the applicant maintained plant equipment under existing programs and to visually observe examples of nonsafety-related equipment determined to be within scope because of the proximity to safety-related equipment and the potential for failure as a result of aging effects.

.1 B2.1.16 One-Time Inspection (XI.M32)

The one-time inspection program was a new program, consistent with NUREG-1801, "Generic Aging Lessons Learned (GALL Report) Tabulation of Results," Volume 2, Revision 1 (hereafter referred to as the GALL Report). The applicant credited the one-time inspection program with verifying the effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis programs through nondestructive evaluation of a sample of components maintained by these programs. Qualified personnel will perform the nondestructive evaluation by using procedures and processes consistent with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code and 10 CFR Part 50, Appendix B. The applicant planned to implement these inspections in the 10 years prior to the period of extended operation.

The team reviewed the license renewal application, the NRC aging management program audit results, aging management program evaluation report, and program procedure. The team evaluated the bases used to identify the inspection samples, and the team discussed the program evaluations and planned activities with the responsible staff.

The team noted that the applicant had evaluated component data, established a detailed sampling plan based on the material and environment combinations, and identified a population of 35 samples to inspect out of an estimated 12,000 components. The team informed the applicant that the NRC and industry had developed improved guidelines for identifying samples based on combinations of materials and the environment. The new guidance was to be included in the next revision of the GALL Report. Applying the improved guidance at Diablo Canyon would result in a more appropriate, increased number of samples for the program. Further, the team noted that the applicant's sampling approach emphasized testing of the material judged to be most susceptible to degradation (typically carbon steel), which could result in failure to identify other susceptible materials. The team considered that the inspection scope should be expanded to other potentially susceptible materials. The applicant initiated Notification 50341874 to re-evaluate the sampling plan to identify the appropriate sample size and scope and address the above concerns.

For the one-time inspection program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described including re-evaluating the sample size and the sampling plan scope of materials to identify the most appropriate samples, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.2 B2.1.17 Selective Leaching of Materials (XI.M33)

The Selective Leaching of Materials program was a new program, consistent with the GALL Report, credited with managing the aging of components made of cast iron, bronze, brass, and other alloys exposed to raw water, treated water, soil, or other environments that may lead to selective leaching. The program will include a one-time visual inspection of a sample of components with metallurgical properties susceptible to selective leaching to determine whether loss of material has occurred and to determine whether any identified selective leaching would affect the ability of the components to perform the intended function during the period of extended operation.

The team reviewed the license renewal application, the NRC aging management program audit results, aging management program evaluation report, and program procedure. The team evaluated the basis used to identify the inspection sample and discussed the program evaluations and planned activities with the responsible staff.

The team also evaluated site-specific operating experience by reviewing relevant action requests. The team noted that Diablo Canyon had previously identified that the December 2008 failure of a buried, gray cast iron fire water system pipe had occurred because of selective leaching. The team concluded that the selective leaching program should be revised to address this known aging effect, including specifying on-going aging management activities to address this aging effect and updating the application, if appropriate. The applicant issued Notification 50341752 to evaluate the most appropriate aging management program to use to monitor this piping.

The team noted that, in 1997, the applicant had also identified indications of “dealloying” on aluminum bronze saltwater system valves. The team was concerned that this dealloying could have resulted from selective leaching of the aluminum bronze. The team concluded that two planned samples of the 26 such components provided an insufficient sample based on this possibility. The applicant would not be able to thoroughly evaluate whether selective leaching existed on this material and environment combination without increasing the sample size or performing destructive examination. The applicant agreed with the team’s concern and added this additional concern in Notification 50341752 to consider revising the sampling plan.

For the Selective Leaching of Materials program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history, with exceptions noted above, to determine the effects of aging in components and systems that have metal alloys subject to this aging mechanism. The team concluded that, pending specification of suitable aging management activities for gray cast iron fire protection system piping and aluminum bronze auxiliary saltwater piping and, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.3 <u>B2.1.18 Buried Piping and Tanks Inspection (XI.M34)</u>

The Buried Piping and Tanks Inspection program was a new program, consistent with the GALL Report, credited with managing cracking, loss of material, and change in the surface conditions of buried components. The applicant included asbestos cement piping in this aging management program because the in-scope fire water systems had this type of piping. The applicant identified that they would manage the effects of aging through inspection either during an opportunistic excavation for other maintenance or during a specifically planned excavation. The applicant will perform one excavation prior to the period of extended operation and one excavation within the first 10 years of the period of extended operation. This program included the auxiliary saltwater, diesel generator fuel transfer, fire protection, and the makeup water systems.

The team reviewed the license renewal application, the NRC aging management program audit results, and applicant's responses to requests for additional information. The team interviewed the system engineers for the auxiliary saltwater, diesel fuel oil transfer and storage, fire protection, and cathodic protection systems. The team interviewed personnel cognizant of aspects of the buried pipe program, including the program owner. The team reviewed the program documents, drawings, corrective actions for previous buried piping issues, plant-specific operating experience evaluations, and procedures. The team also evaluated applicant activities related to the operation and maintenance of the cathodic protection system.

The applicant took two exceptions to the GALL Report. The applicant included buried stainless steel and asbestos cement piping because the applicant had in-scope systems that contained these materials (Elements 1 and 3). The applicant planned visual inspections of stainless steel piping that was not coated or wrapped to detect loss of material resulting from corrosion. Also, visual inspections of buried asbestos cement piping that was not coated or wrapped will be performed to detect evidence of cracking, loss of material, and material changes in surface conditions (Elements 1, 2, 3, 4, and 6). The team agreed that these exceptions ensured that the applicant would meet the intent of the GALL Report after including unwrapped stainless steel and asbestos lined cement piping within the scope of license renewal. The applicant had included applicable requirements for conducting the piping and tank inspections for to be consistent with the GALL Report.

The team determined that the applicant had recently upgraded the cathodic protection system and programs. Nuclear Energy Institute 09-14, "Guideline for the Management of Buried Pipe Integrity," dated January 2010, recommended following the guidance contained in Electric Power Research Institute Report 1016456, "Recommendations for an Effective Program to Control the Degradation of Buried Pipe." The initiative included ranking piping that contained regulated material. The team determined that the applicant had taken actions prior to this initiative to understand and monitor the condition of underground piping. Further, the team determined that the applicant adopted appropriate milestone dates recommended in the initiative letter and had initiated actions to begin risk ranking the systems by January 2011. Also, the applicant was implementing Procedure TS5.ID3, "Buried Piping and Tanks Program," Revision 1, as part of its groundwater contamination and protection initiative.

As a result of external operating experience related to degradation of fire protection systems caused by inadequate backfilling of soil around the piping, the applicant reviewed their fire protection piping design conditions. The applicant determined that original methods of backfilling soil onto the fire protection piping were unlikely to degrade fire protection piping. The applicant further determined that the fire protection pipe installation met the nonsafety-related pipe installation specifications, and once buried components were replaced the system would last beyond the re-licensed period. The applicant had replaced the safety-related fuel oil storage and transfer tanks and piping to comply with state regulations. In 1997 and 1998 for Units 1 and 2, respectively, the applicant replaced portions of the auxiliary saltwater piping.

For the Buried Piping and Tanks Inspection program, the team concluded that the applicant had performed appropriate evaluations of the piping conditions and considered pertinent industry experience and plant operating history to determine the effects of aging on buried piping and tanks. The team concluded that, if implemented as described, the applicant developed guidance to appropriately identify and address aging effects during the period of extended operation.

.4 B2.1.20 External Surfaces Monitoring (XI.M36)

The External Surfaces Monitoring program was a new program, consistent with the GALL Report, credited with managing loss of material for external surfaces of steel, aluminum, copper alloy components, as well as hardening and loss of strength for elastomers in ventilation and mechanical systems. Because the applicant had copper and aluminum alloy components, the applicant expanded the inspections to include those items. The applicant will also visually inspect for aging effects related to hardening and loss of strength of elastomers. The program will use visual inspections during engineering walk downs each refueling cycle to evaluate the condition of bolting, ducting, fans, and flexible connections in ventilation systems, and external surfaces of pumps, valves, piping, tanks, expansion joints, and other mechanical components. During the 10 years prior to the period of extended operation, the applicant planned to incorporate additional plant-specific operating experience and associated lessons learned into this aging management program and their procedures.

The team reviewed license renewal program basis documents, aging management review documents, existing and draft procedures, long-range planning documents, and system engineer qualification procedures. The team interviewed personnel involved with the development of the external surface inspection procedure and performed walk downs to assess the external condition of piping and components. The team confirmed that system engineers presently monitored the external surfaces of their systems in accordance with the guidance contained in Procedure TS5.ID1, “System Engineering Programming,” Revision 15.

The applicant took three exceptions to the GALL Report that expanded the scope of the program (Elements 1, 3, and 4). The first exception included expanding the visual inspections for the effects of aging to include aluminum, copper alloy, and elastomers. Because the applicant included elastomers within this program, the second exception identified elastomer hardening and loss of strength as additional aging effects that required managing. The third exception specified manually moving elastomers as an appropriate method to augment the visual inspections. The team considered these exceptions appropriate since they expanded the program to include materials of in-scope components and included actions to manage the effects of aging. Although the applicant had historically required system engineers to look for degraded conditions, the applicant had not specifically identified those conditions (e.g., corrosion, through wall leaks) as signs of aging effects in Procedure TS5.ID1, the applicant considered this a new program.

The team determined from review of corrective action documents that system engineers had successfully identified degraded conditions on plant equipment external surfaces since establishing system engineers in 1993. Issues identified included systems within the scope of license renewal, and involved corrosion, leaks, and pitting issues. The team concluded that the applicant implemented the current program in a manner that detected and corrected age-related degradation of external surfaces.

The applicant specified that personnel performing external surface inspections would be specifically qualified. The team reviewed the type of external surface inspection training that system engineers have had related to erosion, corrosion, and degraded coatings on piping. The team reviewed training records of several system engineers related to the qualification specified in Procedure TS5.ID1. The team determined that the training provided to system engineers at the time of the inspection did not meet the commitment the applicant described in the External Surfaces Monitoring program aging management program evaluation report. The applicant initiated Notification 50335453 to identify this deficiency and to identify the new training and skills to ensure system engineers could effectively monitor external corrosion and material condition of structures systems and components, as required by this program. The applicant indicated that they would provide the appropriate training to personnel based upon the analysis as part of their Project Plan for License Renewal Implementation.

For the External Surfaces Monitoring program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on the external surfaces of the included components. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.5 <u>B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E1)</u>

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program was a new program, consistent with the GALL Report, credited with managing the aging effects of cables/cable jackets, connections and terminal blocks exposed to adverse localized environments caused by heat, radiation, or moisture. The aging effects included embrittlement, melting, cracking, swelling, surface contamination, or discoloration of cables, connections, and terminal blocks. The applicant planned to monitor the aging effects through periodic visual inspections of cables, connectors and terminal blocks in accessible areas. As further specified in the GALL Report for inaccessible cables, the applicant planned to use engineering evaluations to demonstrate that they would be similarly unaffected or requires corrective actions. The applicant will complete the first inspection sample of these cables prior to entering the period of extended operation and once every 10 years thereafter. At the time of the inspection the applicant had not established a sample size for evaluation.

The team reviewed relevant license renewal program basis documents, aging management review documents, existing and new procedures, plant specific operating experience, and preventive maintenance requirements. The team interviewed the license renewal project personnel and the responsible engineers. The team walked down numerous accessible areas within the plant where cable trays and exposed cables were installed, including the cable spreading rooms. The team interviewed plant personnel regarding their plans for developing a procedure and conducting these aging effects evaluations. Plant personnel described that their program will be closely modeled on, and incorporate the guidance in, Electric Power Research Institute Report TR-109619, "Guideline for Management of Adverse Localized Environments," dated June 1999.

From review of plant-specific operating experience, the team identified examples where the applicant had already successfully identified aging of cables and replaced cables subject to adverse localized environments. In 1992, a scheduled inspection of Reactor Coolant Pump 1-4 identified heat related cracking of the cable jacket in the high temperature environment surrounding the reactor coolant pump terminal box. Because the cable continued to deteriorate, the applicant replaced the power cables for all of the reactor coolant pumps to protect against future failure. The applicant performed follow-up inspections as part of normal plant maintenance, testing, and inspections and had not identified any additional degradation for the replaced cables.

For the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for cables/cable jackets, connections, and terminal blocks exposed to adverse localized environments. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.6 B2.1.35 Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E6)

The Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program was a new, one-time program, consistent with the GALL Report, credited with managing aging effect of loosening of bolted external connections because of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation to ensure that electrical connections remained capable of performing their intended function.

The team reviewed relevant license renewal program basis documents, aging management review documents, existing and new procedures, and preventive maintenance requirements. The team interviewed license renewal project personnel and the responsible engineers. Because this is a new one-time inspection program, the applicant had not yet developed any program or procedure documents for performing these inspections to verify whether a periodic aging management program would be required.

The applicant took exception to the GALL Report periodic program and specified a one-time program in accordance with draft interim staff guidance. The interim staff guidance, the draft GALL Report, Revision 2 and the applicant's program narrowed the scope of connections to external connections, specifically excluding internal connections, limiting the frequency of testing, and adjusting the sample size of connections to be tested. Therefore, the team concluded the applicant had established a program consistent with the latest NRC guidance and consistent with the intent of the GALL Report.

The applicant planned to: (1) conduct a one-time test of a representative sample of external connections prior to the period of extended operation using infrared thermography to determine whether aging effects existed that require management; (2) select the sample based upon application (medium and low voltage), circuit loading (high load), and environment (temperature, high humidity, vibration, etc.), and (3) document the technical basis for the sample selected and the acceptance criteria used for each inspection or test for the specific type of cable connections. The applicant had not developed a specific sample size at the time of the inspection.

The applicant planned to establish acceptance criteria for thermography testing on the temperature rise above the reference temperature. The reference temperature will be the ambient temperatures or baseline temperature data from the same type of connections being tested. If thermography inspection was not possible or if the results were inconclusive, the connection integrity can be confirmed by another acceptable connection integrity test method such as contact resistance measurement.

The applicant routinely performed infrared thermography on electrical components and connections as part of the current predictive maintenance program. A search and review of the plant operating experience identified electrical connections showing thermal anomalies that resulted from significant temperature variances between phases or from normal temperatures. When the applicant detected anomalies, they monitored the condition closely for degradation or initiated corrective actions. No loss of equipment intended function had occurred.

For the Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on electrical connections. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation that was consistent with the current licensing basis.

b.3 Evaluation of Existing Aging Management Programs

The team sampled 18 of the 31 existing aging management programs, which included one plant specific aging management program, to determine whether the applicant had taken or planned to take appropriate actions to manage the effects of aging, as specified in the GALL Report.

The team reviewed site-specific operating experience to determine whether there were any aging effects for the systems and components within the scope of these programs that had not been identified from the applicant's review of industry operating experience.

The team evaluated whether the applicant implemented or planned to implement appropriate actions to manage the affects of aging. These programs have established procedures, records of past corrective actions, and previous operating experience related to applicable components. Further, some programs required the applicant to implement enhancements (i.e., program aspects that will be implemented prior to the period of extended operation) to ensure consistency with the GALL Report.

The team walked down selected in-scope SSCs to assess how the applicant maintained plant equipment under the current operating license, to visually observe examples of nonsafety-related equipment determined to be in-scope because of the proximity to safety-related equipment, and to assess the potential for failure as a result of aging effects.

.1 B2.1.2 Water Chemistry (XI.M2)

The Water Chemistry program was an existing program, consistent with the GALL Report, credited with managing the effects of aging caused by cracking, denting, hardening and loss of strength, loss of material, reduction of heat transfer, and wall thinning in primary and secondary water systems. The Water Chemistry program maintained the chemical environment in the reactor coolant system and related auxiliary systems, and maintained the chemical environment in the steam generator secondary side and the secondary cycle systems. The one-time inspection program described inspections planned to verify the effectiveness of chemistry control programs by evaluating whether significant degradation has occurred prior to entry into the period of extended operation.

The team reviewed the license renewal application, the NRC aging management program audit results, the aging management program evaluation report, and program procedures. The team also reviewed: site strategic chemistry plans; chemistry operating experience evaluations; chemistry procedures; chemistry-related action requests; and primary and secondary chemistry data/trends for the past 5 years. In addition, the team interviewed plant chemists. The team verified that the applicant administered the water chemistry programs in accordance with Technical Specifications and guidance contained in Electrical Power Research Institute Reports TR-1014986, "Pressurized Water Reactor Primary Water Chemistry Guidelines," Revision 6, and TR-1016555, "Pressurized Water Reactor Secondary Water Chemistry Guidelines," Revision 7. The team reviewed the last three quality assurance chemistry audits and the periodic quality verification reports completed since 2005.

The team determined that the applicant had maintained their chemistry parameters well within their administrative limits and had not exceeded any action levels. The team verified that the applicant took appropriate corrective actions in response to deficiencies identified in corrective action documents. The applicant used zinc injection to help minimized primary water stress corrosion cracking in their steam generators by creating a protective oxide layer. The applicant maintained a lithium control program to create a pH environment that was not conducive to corrosion in the primary plant. The licensee established a reducing environment in their steam generators by addition of an amine and hydrazine to scavenge oxygen.

For the Water Chemistry program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging. The team concluded that, if implemented as described, the applicant provided guidance to appropriately address aging effects for the reactor coolant system and the steam generators during the period of extended operation.

.2 B2.1.4 Boric Acid Corrosion (XI.M10)

The Boric Acid Corrosion program was an existing program, consistent with the GALL Report, credited with managing the loss of material resulting from boric acid leakage. The program implemented the recommendations in NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants," to monitor the condition of the reactor coolant pressure boundary for borated water leakage. The program inspected for leakage during normal operations and during reactor coolant system pressure tests, identified leak paths and quantified the leakage, removed the boric acid residues, assessed for any damage caused by boric acid leakage, and conducted follow-up inspections to verify the adequacy of corrective actions taken to isolate the leakage. The program maintained tracking and trending records for boric acid leakage from plant components and established a component-based visual history of boric acid leakage/seepage. The applicant managed the effects of aging by visually inspecting the external surfaces of mechanical and structural components in any system that contained borated water and protected electrical components on which borated water may leak.

The team reviewed the aging management program evaluation report, the NRC aging management program audit report, implementing procedures, self assessments, relevant action requests, notifications, work orders, summaries of associated plant and industry operating experience, and the applicant's tracking data base of boric acid indications. In addition, the team discussed program development, response to NRC generic communications, program implementation, and self-assessment results with engineers to understand the program and how assessments and operating experience have been incorporated into the program. The team walked down accessible systems containing borated water to assess the material condition of plant components and the status of any boric acid leakage. The team reviewed corrective actions taken for leaks identified during boric acid inspections to assess the effectiveness of the program for identifying, monitoring, trending, and correcting boric acid leaks from systems containing borated water.

For the Boric Acid Corrosion program, the team concluded that the applicant had performed the appropriate evaluations and considered pertinent industry experience and site-specific operating history to determine the effects of aging on piping and component surfaces. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.3 B2.1.6 Flow-Accelerated Corrosion (XI.M17)

The Flow-Accelerated Corrosion program was an existing program, consistent with the GALL Report, designed to manage wall thinning resulting from flow-accelerated corrosion on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies that contain high energy fluids (both single-phase and two-phase fluids). The program implemented the Electric Power Research Institute guidelines in NSAC-202L, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” Revision 3, using Procedures TS1.ID1, "Flow-Accelerated Corrosion Monitoring Program Interfaces and Responsibilities," Revision 2, and TS1.NE1, "Flow-Accelerated Corrosion Monitoring Program," Revision 6, to detect, measure, monitor, predict, and mitigate component wall thinning.

The team reviewed applicable license renewal program basis documents, aging management review documents, and existing procedures. In addition, the team searched the applicant’s corrective action database for relevant operating experience. The team also interviewed plant personnel, examined specimens of piping demonstrating the effects of flow-accelerated corrosion, and reviewed specifications for specific chromium-content piping.

The team determined that the GALL Report endorsed Revision 2 of NSAC-202L. The team reviewed an Electric Power Research Institute document that compared NSAC-202L, Revisions 2 and 3, and determined that Revision 3 incorporated lessons learned and improvements to detection, modeling, and mitigation technologies that became available since the Electric Power Research Institute had published Revision 2. The updated recommendations refined and enhanced those of previous revisions without contradictions to ensure continuity of existing plant flow-accelerated corrosion programs.

The applicant achieved the objectives of the Flow-Accelerated Corrosion program by: (1) identifying system components susceptible to flow-accelerated corrosion; (2) performing analysis using the predictive code CHECWORKS to determine critical locations for inspection and evaluation; (3) providing guidance for follow-up inspection; (4) repairing, replacing, or performing evaluations for components not acceptable for continued service; and (5) evaluating and incorporating the latest technologies, industry and site-specific operating experience. The team determined the procedures and methods used in the flow-accelerated corrosion program were consistent with commitments to Bulletin 87-01, “Thinning of Pipe Wall in Nuclear Power Plants,” and Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.”

To aid in the planning of inspections and choosing inspection locations, the applicant utilized Electric Power Research Institute predictive code CHECWORKS that used the implementation guidance described in NSAC-202L, Revision 3. The applicant periodically updated the CHECWORKS model based on the inspection results, changes in the plant design or operating conditions, and changes in pipe configurations. For example, the applicant included criteria in the model to account for small bore piping inspections for piping 2 to 4 inches in diameter. However, the applicant did not model small-bore piping with a nominal diameter of two inches or less since it was not suitable for CHECWORKS modeling.

For the Flow-Accelerated Corrosion program, the team concluded that the applicant had performed appropriate evaluations and had considered pertinent industry experience and plant operating history to determine the effects of aging on carbon and low-alloy steel piping and component surfaces. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.4 B2.1.9 Open-Cycle Cooling Water System (XI.M20)

The Open-Cycle Cooling Water System program was an existing program, consistent with the GALL Report, credited with managing the aging effects resulting from material loss and reduction of heat transfer for components in, or cooled by, open-cycle cooling water systems. The applicant managed the aging effects of material loss and heat transfer reduction through heat exchanger performance monitoring and periodic maintenance, surveillance tests and chemistry control techniques. The applicant implemented the maintenance and test requirements in accordance with their commitments to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989, and in response to Letters DCL 94-037, "Auxiliary Saltwater System Operability," dated February 15, 1994, and DCL 94-174, "Reply to Notice of Violation in NRC Enforcement Action 94-056 (NRC Inspection Report Nos. 50-275/94-08 and 50-323/94-08), dated June 3, 1994. The components included within the scope of this program included the auxiliary saltwater system piping and the component cooling water heat exchangers.

The team reviewed the implementing procedures and selected test results related to pipe inspections, monthly flow tests, intake bay inspections, and heat exchanger macrofouling inspections for each component cooling water heat exchanger. The team reviewed selected corrective actions for identified deficiencies. In addition, the team interviewed the program manager and walked down accessible portions of the auxiliary saltwater piping. The team determined from interviews with the program owner, reviews of selected heat transfer test results, and other pipe inspection information that the applicant successfully monitored heat transfer and loss of material in component cooling water heat exchangers and auxiliary saltwater piping, respectively. The team verified that Procedure MA1.ID20, "Testing and Inspections for the Auxiliary Saltwater System for Compliance with NRC Generic Letter 89-13," Revision 2, appropriately established requirements to perform activities that enabled the applicant to manage the effects of aging.

The team verified that the applicant continuously chlorinated the auxiliary saltwater system and alternated flow through each component cooling water heat exchanger weekly to minimize low flow and stagnant areas and to ensure that each heat exchanger was chlorinated to minimize microbiologically induced corrosion and biological fouling. From a review of the heat exchanger test results, the team determined that the mid-cycle and refueling outage heat exchanger tube cleaning by a mechanical brush ensured the heat exchanger remained capable of removing the design basis heat load. The applicant inspected the inside of the auxiliary saltwater piping at the intake structure, the component cooling water heat exchangers, and the vacuum breaker vaults on a 4-cycle frequency. From a review of corrective action documents, the team determined that the applicant effectively monitored for corrosion inside the auxiliary saltwater piping and maintained the plastic pipe coating in good condition. The applicant conducted eddy current testing on 20 percent of the tubes in each component cooling water heat exchanger every refueling outage plus any tubes that had prior evidence of wall thinning.

From a review of Procedure MA1.ID20, the team determined that the applicant identified that heat transfer testing was prudent although not required by their commitments to Generic Letter 89-13. The team verified that the applicant had completed heat transfer tests on each of the heat exchangers prior to entering refueling outages since 2004. In addition, the component cooling water heat exchangers were tested prior to each outage to demonstrate their heat transfer capability. The team identified that the current program procedure did not match the commitments specified in the license renewal application. Notification 50359698 documented the need to revise Procedure MA1.ID20 to align with the requirements in the license renewal application.

For the Open-Cycle Cooling Water System program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in components cooled by open-cycle cooling water. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.5 B2.1.10 Closed-Cycle Cooling Water System (XI.M21)

The Closed-Cycle Cooling Water System program was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material, cracking, and reduction in heat transfer for components in closed-cycle cooling water systems. The program included maintenance of system corrosion inhibitor concentrations and chemistry parameters following the guidance of Electric Power Research Institute TR-107396, “Closed Cooling Water Chemistry Guideline,” Revision 1, to minimize the effects of aging. The program included periodic testing and inspections to evaluate system and component performance. Inspection methods included visual, ultrasonic, and eddy current testing.

The applicant maintained water chemistry in the component cooling water and service cooling water systems by adding corrosion inhibitors (potassium molybdate, potassium nitrite, and tolyltriazole), pH control chemicals (potassium hydroxide), and biocides (glutaraldehyde and isothiazoline). The systems addressed by this license renewal program included diesel generator jacket water, component cooling water, service cooling water, and the auxiliary building heating, ventilation and air conditioning chill water systems. The team confirmed that the applicant only included the service cooling water and the heating, ventilation and air conditioning chill water systems because of their potential for spatial interactions with safety-related systems.

The team reviewed the implementing procedures, self-assessments, strategic chemistry plans, and chemistry data for the component cooling water and diesel jacket water systems. The team reviewed selected corrective action documents and confirmed that the applicant had satisfactorily resolved the identified problems. The team interviewed the component cooling water system engineer, the diesel generator system engineer, and chemistry personnel.

The team determined that the applicant planned to enhance this program by performing inspections of the component cooling water isolation check valves to the reactor coolant pumps (Valves CCW-1-585 and CCW-2-585) as a leading indicator of the interior piping components otherwise inaccessible for visual inspection. The applicant planned to perform the inspections every 5 years (Elements 4, 5, 6, and 7). Because the applicant had experienced some fouling and had low flow areas and because the applicant had not selected these valves based on a technical evaluation regarding whether the flow conditions represented the typical low flows in the component cooling water system, the team questioned whether these valves would provide the needed information since they were not located in low flow areas. The applicant initiated Notification 50341717 to evaluate whether performing inspections at these locations provided representative low-flow conditions for the closed cooling water system.

The applicant took five exceptions to the GALL Report. The first exception related to the concentration of chromates in the diesel jacket water system (Elements 2, 3, and 6). The applicant used a chromate concentration that ranged from 1580 to 3150 ppm, whereas, the guidelines in Electric Power Research Institute Report TR-107396 specified a range of 150 to 300 ppm. The chromate limit resulted from a study identified in National Association of Corrosion Engineers 7G181 that documented chromate levels above 500 ppm had degraded some mechanical seals. The team determined that the applicant had experienced some leaks of their jacket water pump seals; however, the applicant concluded the seal leakage had not resulted from high chromate levels. The applicant initiated Notification 50341936 to evaluate the cause for the seal failures. The team verified that the applicant had experienced leakage from jacket water pump seals, but no catastrophic seal failures. Further, the majority of the seal replacements had occurred after 15 years in service. The applicant replaced the jacket water pumps every 13 years. Although no definitive proof existed that the seal leakage resulted from high chromate levels in the jacket water, the team determined that the frequency of the preventive maintenance task provided an appropriate means to manage any aging effects.

The second exception related to the decision to not monitor chloride and fluoride as control parameters for the diesel jacket water system (Elements 2 and 3). The applicant supported this exception to the GALL Report by noting that demineralized water was used to makeup to the system, no pathways existed to allow chlorides and fluorides into the system, and the chromate prevented pitting by chlorides and fluorides because of the anodic inhibitor properties of the high chromate concentration. The team verified that the applicant used demineralized water to makeup to the diesel jacket water system and confirmed that chromate acts as an anodic inhibitor. The team identified no concerns with this exception.

The third exception related to the monitoring frequency for the jacket water control parameters quarterly instead of monthly, as specified in the GALL Report (Elements 2 and 3). The team determined that the chemistry parameters remained stable for long periods of time such that decreasing the sampling frequency to quarterly remained frequent enough to detect changes in chemistry in a timely fashion. The team verified that the applicant had maintained stable water chemistry for the past 25 years and verified that the jacket water system remained closed with little chance of contamination. The team identified no concerns with this exception.

The fourth exception related to using chemistry controls and other evaluation techniques for the different closed cooling water systems instead of monitoring heat exchanger parameters such as flow, inlet and outlet temperatures, and differential pressure (Elements 3, 4, and 5). Instead of testing the heat exchangers serviced by component cooling water system (e.g., component cooling water, centrifugal charging pump, safety injection pump lubricating oil coolers and the residual heat exchanger), the applicant credited monitoring of corrosion coupons, heat transfer testing of the component cooling water heat exchanger, inspection of the interior of the component cooling water isolation valves to the reactor coolant pumps, and inspection of low flow spool pieces. For the diesel jacket water system, the applicant credited monitoring of the jacket water supply and return header temperatures, hydrostatic testing of the jacket water after coolers, and visual inspection of the jacket water radiators. The team had no concerns with this exception.

The fifth exception related to using Electric Power Research Institute 1007820, “Closed Cooling Water Chemistry Guideline,” Revision 1 instead of Revision 0, as described in the GALL Report (Elements 2, 3, 4, 5, 6, and 7). The team identified no concerns related to implementing a newer version of the chemistry guideline.

From a review of plant operating experience, the team determined the applicant had appropriately resolved past contamination of their closed cooling water systems. The applicant had experienced a significant biofouling event in 2005 in the closed cooling water system. The applicant identified the root cause as poor chemistry control after changing corrosion control from chromates to molybdates in 1991. The applicant began adding a dispersant to the closed cooling water system that enabled the molybdates to penetrate throughout the biofilm minimizing any biological growth.

From a review of plant operating experience, the team confirmed that the applicant had taken appropriate actions to maintain chemistry controls in the auxiliary building heating, ventilation, and air conditioning chill water system. The team determined that, for the service cooling water system, the applicant took appropriate actions to mechanically clean and chemically treat the service cooling water system whenever chemistry parameters exceeded their recommended ranges.

For the Closed-Cycle Cooling Water System program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in components cooled by closed-cycle cooling water. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.6 B2.1.13 Fire Water System (XI.M27)

The Fire Water System program was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material resulting from general, pitting, crevice, and galvanic corrosion; microbiological corrosion; or biofouling of carbon steel, stainless steel, cast-iron, copper, bronze, brass, galvanized, and ductile iron components in fire protection systems exposed to water. The Fire Water System program managed the aging of piping, pipe components, pump casings, sprinkler heads, tanks, and hydrants as well as loss of material in fire protection system components through periodic hydrant inspections, fire main flushing, sprinkler inspections and flow testing in accordance with National Fire Protection Association codes and standards.

The team reviewed applicable license renewal program basis documents, aging management review documents, procedures and surveillances, and surveillance results. In addition, the team searched the applicant's corrective action database for relevant operating experience. The team also interviewed plant personnel and walked down fire water system equipment, including the fire pumps, associated piping, and the reservoir. The team determined that plant specific operating experience did not reveal anything that would require changes to this aging management program.

The applicant intended to enhance the Fire Water System program to replace sprinkler heads in service for 50 years or to test representative samples from one or more fire areas consistent with guidance in National Fire Protection Association 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." The applicant will repeat the tests at 10-year intervals during the period of extended operation for sprinkler heads not replaced prior to being in service for 50 years to manage the effects of aging.

The applicant planned to enhance procedures to perform either periodic, non-intrusive volumetric examinations or visual inspections on firewater piping. Non-intrusive volumetric examinations would detect loss of material resulting from corrosion to ensure that aging effects were managed, wall thickness remained within acceptable limits, and degradation would be detected before the loss of intended function. The applicant planned to use volumetric examination techniques generally accepted in the industry, such as ultrasonic or eddy current testing. For monitoring and trending, the licensee planned to enhance Procedure STP M-71, "Fire Water System Flow Test," Revision 8, to specify trending requirements.

The applicant took exception to the GALL Report recommendations to conduct annual fire hose hydrostatic tests and annual hose station gasket inspections. The applicant specified that they would continue to maintain their 18-month hose station gasket inspection frequency and their 3-year fire hose hydrostatic test frequency. The team concluded that the planned frequencies for the hose station gasket inspections and the fire hose hydrostatic tests were satisfactory and capable of detecting degradation that resulted from aging effects since these frequencies agreed with the periodicity typically observed.

For the Fire Water System program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on fire water system internal pipe and component surfaces. With the enhancements to be incorporated prior to the period of extended operation, the team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.7 B2.1.14 Fuel Oil Chemistry (XI.M30)

The Fuel Oil Chemistry program was an existing program, consistent with the GALL Report after enhancement, credited for managing the loss of material that resulted from general, pitting, crevice, and microbiological influenced corrosion on the internal surface of components in the diesel engine generator diesel fuel oil storage and transfer system, portable diesel-driven fire pump fuel oil tanks, and portable caddy fuel oil tanks. The program included surveillance and monitoring procedures for maintaining fuel oil quality. The applicant controlled contaminants in accordance with applicable American Society of Testing Materials (ASTM) standards (ASTM D1796, D2276, and D4057). Further, the applicant conducted periodic draining of water from fuel oil tanks, visual inspection of internal surfaces, one-time ultrasonic wall thickness measurements of accessible portions of fuel oil tank bottoms, and testing of new fuel oil before introducing it into the fuel oil tanks. In addition, the applicant planned supplemental one-time inspections of a representative sample of components in systems that contain fuel oil by the one-time inspection program.

The team reviewed the aging management program evaluation report, the NRC aging management program audit report, responses to requests for additional information, implementing procedures, self-assessments, and relevant action requests. The team reviewed trends and data for the diesel fuel oil parameters and determined the applicant maintained the chemistry parameters within limits. The team interviewed plant personnel and conducted walk downs of the diesel engine generators, diesel engine generator day tanks, portable diesel-driven fire pump, and portable caddy pumps. From a review of plant operating experience, the team determined that no additional aging effects were identified and identified no concerns.

The applicant specified enhancements needed to ensure consistency with the GALL Report for all the fuel oil tanks that required aging effects management. Specifically, the applicant identified needed procedure changes to: (1) require periodic draining, cleaning, and visual inspection of the diesel engine generator day tanks, portable diesel-driven fire pump fuel oil tanks, and portable caddy fuel oil tanks (Elements 2 and 4); (2) require sampling of new fuel oil prior to introduction into the portable diesel-driven fire pump and caddy fuel oil tanks (Elements 3 and 5); (3) require one-time supplemental ultrasonic thickness measurements of accessible portions of fuel oil storage tank bottoms (Element 4); (4) specify trending of water and particulate levels specified in Technical Specifications and plant procedures for the diesel fuel oil storage tanks and diesel engine generator day tanks (Element 5); (5) require monitoring and trending of water and sediment levels for new fuel oil for the portable diesel-driven fire pump and caddy fuel oil tanks (Element 5), and (6) specify acceptance criteria for new fuel oil being introduced into the portable diesel-driven fire pump or caddy fuel oil tanks (Element 6). After review of the aging management program and discussions with applicant personnel, the team determined that these enhancements enabled the applicant to ensure their aging management program procedures monitored the in-scope components for aging effects.

The applicant described six separate exceptions to the GALL Report that affected several aging management program elements. The team discussed the basis for each exception with the program owner and verified the applicant remained capable of managing aging effects, as required by the GALL Report.

The first exception related to the scope of the Fuel Oil Chemistry program and the specific ASTM standards used. The applicant used ASTM D1796, -D2276, and -D4057, as specified in their Technical Specifications (Element 1). The applicant specified that testing conducted using ASTM D1796 provided quantitative results that, together with the Technical Specifications acceptance criteria, met the intent of the ASTM D2709. Additionally, Technical Specification 5.5.13.c specified the use of ASTM D2276, along with acceptance criteria for total particulate concentration of less than 10 mg/liter. The team determined the applicant specified fuel oil chemistry monitoring that would manage aging effects.

The second exception related to periodic removal of water from the tanks (Elements 2 and 5). The applicant did not have a low point drain to periodically remove water from the portable diesel-driven fire pump fuel oil tanks, portable caddy fuel oil tanks, or the fuel oil pump head tanks. The team confirmed that the fuel oil pump head tanks replenished the fuel oil in the head tanks daily and confirmed the fuel came from the diesel generator day tanks. The applicant checked for the presence of water in the diesel generator day tanks every 31 days and drained as necessary.

Although the applicant operated the portable diesel-driven fire pump and caddy pumps quarterly, the team determined that the test duration would not empty the fuel oil tanks and would not, necessarily, prevent water collection. The team verified that the annual maintenance on the portable diesel-driven fire and caddy pumps required draining and cleaning of the fuel oil tanks. The team concluded this frequency of maintenance, draining and drying the interior of the tanks, and the future enhancement of monitoring for the presence of water prior to adding fuel oil would provide sufficient preventive actions to manage the effects of aging.

The third exception related to the fuel oil in the portable diesel-driven fire pump and caddy fuel oil tanks not being monitored for particulate concentration (Element 3). The team concluded this frequent maintenance that the drained and dried the interior of the tanks and the future enhancement of monitoring for the presence of particulates prior to adding fuel oil would provide sufficient monitoring to manage any aging effects. The fuel oil pump head tanks replenished the fuel oil in the head tanks daily and that the applicant checked for particulates quarterly in accordance with ASTM D2276 and the Technical Specifications.

The fourth exception related to the inability to take multi-level representative fuel oil samples from the small tanks in accordance with ASTM D4057 (Elements 3 and 4). From walk downs, the team confirmed that the system design of the portable diesel-driven fire pump fuel oil tanks, portable caddy fuel oil tanks, and the fuel oil pump head tanks did not allow performing multi-level sampling. The team identified no concerns with this exception.

The fifth exception identified that testing conducted using ASTM D1796 gives quantitative results that, together with the Technical Specification acceptance criteria, meet the intent of the ASTM D2709 method (Elements 3 and 6). Specifically, the applicant used ASTM D1796, along with acceptance criteria for water and sediment contamination of 0.05 volume percent, as specified in Technical Specifications Bases for Surveillance Requirement 3.8.3.3.c. The team determined that the applicant used a sample volume smaller than that recommended in ASTM D2276. The team determined that the ASTM standard recommended a larger volume but allowed for smaller sample volumes so long as the volume was recorded. Further, the team confirmed that the applicant had specified this methodology and the use of a smaller sample volume in the bases of their Improved Technical Specifications submittal. The team identified no concerns with this exception.

The sixth exception related to the filter pore size used to determine the particulate levels in the fuel oil samples. The applicant used a 0.8-micron filter in accordance with ASTM D2276 along with acceptance criteria for total particulate concentration less than 10 mg/liter, as specified in Technical Specification 5.5.13.c; whereas, the GALL Report recommended using a larger 3.0-micron filter and a minimum flow of at least one gallon in accordance with ASTM D6217. The team determined that the 0.8-micron filters would not create any adverse conditions since this filter size was a more sensitive measurement.

The team determined the applicant had established aging management program elements that implemented the GALL Report elements in a manner that would manage the effects of aging with the exceptions described above. The team determined the aging management program description of the exceptions did not clearly describe why their alternative methods ensured that they provide the same level of protection for aging effects described in the GALL Report. The applicant initiated Notification 50341844 to ensure they clearly describe the basis for the exceptions and how they met the intent of the aging management program elements.

For the Fuel Oil Chemistry program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on internal surfaces of the diesel fuel oil system tanks. With the enhancements to be incorporated prior to the period of extended operation, the team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.8 B2.1.23 Lubricating Oil Analysis (XI.M39)

The Lubricating Oil Analysis program was an existing program, consistent with the GALL Report after enhancement, credited for managing the quality of lubricating oil in mechanical systems within specified limits. The program provided for sampling and analysis to maintain lubricating oil contaminants, primarily water and particulates, within the acceptance criteria established in vendor or industry guidelines. In addition, ferrography may be performed on oil samples for trending of particle concentrations for diagnostic purposes.

The team reviewed the aging management program evaluation report, the NRC aging management program audit report, program assessments, implementing procedures, and relevant notifications. The team interviewed plant personnel, reviewed a sample of oil analysis results, trending results, and lubricant evaluations for systems within the scope of license renewal, verified acceptance criteria consistency with vendor manuals and industry guidance, and reviewed the plant's operating experience summary document to ensure adequate operating experience was considered. The team determined that the applicant already evaluated the condition of lubricating oil samples using preventive maintenance tasks; however, the applicant had developed a draft procedure that they planned to implement to monitor for aging effects as part of their license renewal activities.

The Lubricating Oil Analysis program enhancements necessary to meet the GALL Report included developing a procedure to: (1) govern program testing, evaluation, and disposition for in-scope equipment (Element 1); (2) provide guidance for oil sampling and analysis for chemical and physical properties (Element 2); (3) specify standard analyses (Element 3); and (4) incorporate the acceptance criteria for lubricating oils associated with the equipment within the scope of the program (Elements 4 and 6).

The applicant took exception to the GALL Report because the applicant measured fuel dilution (fuel contamination of the lubricating oil) by gas chromatography rather than the flash point testing of industrial oil applications as described in the GALL Report. The applicant measured fuel dilution by gas chromatography on internal combustion engine applications where the potential exists for contamination of the lubricating oil. During interviews, applicant personnel provided information that demonstrated that measuring fuel dilution by gas chromatography accomplished the same goal as the flash point test by determining the percent by volume of fuel contaminants in the lubricating oil. The team found this exception acceptable.

For the Lubricating Oil Analysis program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging. With the enhancements to be incorporated prior to the period of extended operation, the team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.9 <u>B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E3)</u>

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program was an existing program, consistent with the GALL Report after enhancement, credited with managing localized damage and breakdown of insulation in inaccessible medium voltage cables exposed to adverse environments. The adverse environments for these cables could include exposure to significant moisture while energized. The applicant had been managing the aging effects by periodic inspection for water collection in susceptible cable manholes, pull boxes, and conduits and pumping or draining water as needed. The applicant planned to periodically test in-scope cables to assess the condition of the insulation. The applicant will complete the testing of the inaccessible medium voltage cabling prior to entering the period of extended operation and once every 10 years thereafter. The components and cables included within the scope of this program included control and power cables for the auxiliary saltwater pumps, 480 Vac Buses F, G, and H bus supply cables, component cooling water pumps, and Unit 2 startup transformer feeder cables.

The team reviewed applicable license renewal program basis documents, aging management review documents, program procedures, and records for completed maintenance activities. In addition, the team searched the applicant's corrective action database for relevant action requests. The team interviewed plant personnel, reviewed numerous photographs of previous pull-box inspections, and reviewed records regarding water removed from pull-boxes and conduits. The team walked down several underground cable vaults.

The applicant planned to enhance this existing program to be consistent with the GALL Report and to conduct testing that will provide an indication of the conductor insulation condition for the in-scope cables. The applicant will conduct a polarization index test, as described in Electric Power Research Institute TR-103834-P1-2, "Effects of Moisture on The Life of Power Plant Cables," or other testing considered state-of-the-art at the time of the testing to detect deterioration of insulation. The acceptance criteria for each test will be specific for the type of test performed and the specific cable tested.

The team determined that the applicant did not have any criteria in their Maintenance Rule program structural inspections to evaluate the condition of the supports within pull-boxes that supported the safety-related cable, and that the applicant did not specify a maximum droop for the cables stretched across a cable pull-box. The applicant added these items to Notification 50313350 to ensure they were added when the applicant revised their procedures to examine the effects of aging for license renewal. The applicant provided a schedule for pull-box inspections during the upcoming Unit 1 outage. The team provided inspection recommendations to the resident inspectors who will visually verify the condition of those pull-boxes and associated cables.

The applicant had inspected cable pull boxes with a potential for water intrusion that contain in-scope non-environmentally qualified inaccessible medium voltage cables since January 2000 on a 2-year frequency. The applicant based the frequency of the inspections on plant experience with water accumulation in the cable pull boxes. If the applicant found water inside any of the pull boxes, the applicant removed the collected water and considered adjusting the inspection frequency.

The applicant had experienced several water accumulation issues relating to the sump pumps and had taken appropriate corrective action to resolve these issues. The applicant verified the functionality and condition of the sump pumps annually. Since November 2003, no alarms or pump failures had occurred. The applicant had removed conduit seals or installed vents to allow air circulation to prevent water accumulation in the conduits. When the applicant found conduits with water accumulation, they drained the water and monitored the conduits to verify that no water returned. The applicant had identified no water accumulation in any conduits since April 2005 and no cables had been submerged in pull boxes for at least 10 years. The team determined that the applicant had replaced the original cable with new cable between December 1994 and April 2009. The team determined that none of the original cable that may have been submerged remained in the plant.

For the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for inaccessible cables. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.10 B2.1.27 ASME Section XI, Subsection IWE (XI.S1)

The ASME Section XI, Subsection IWE program was an existing program, consistent with the GALL Report, credited with managing aging effects related to loss of material and loss of integrity of the steel liner of the concrete containment building by performing visual inspections of accessible portions of the containment liner. The applicant inspected accessible portions of the containment liner plate and its integral attachments, such as piping and electrical penetrations, access hatches, the fuel transfer tube, and pressure-retaining bolting. The general visual examination looked for indications of degradation that may affect the containment structural integrity or leak tightness. The applicant recorded indications of material loss, excessive corrosion, pitting, excessive wear, loss of protective coatings, or general deformation; assessed the initial condition of surfaces; and determined the magnitude and extent of indications of degradation of these containment components.

The team reviewed applicable license renewal program basis documents, aging management review documents, and industry documents related to containment liners. In addition, the team reviewed selected relevant corrective action documents and interviewed responsible system and civil engineers. The team reviewed the applicant's program and inspection procedures. The team found the program implemented the inspection requirements of the ASME, Section XI, Subsection IWE. In addition, the team verified that the applicant used inspection criteria that met the regulatory requirements and used qualified personnel to perform the visual examinations. From a review of corrective action documents, the team determined that the applicant had taken appropriate corrective actions for identified deficiencies.

The applicant took six exceptions to the GALL Report. The first exception credited the Appendix J program with testing the pressure retaining seals and gaskets, electrical penetrations and access hatches, respectively. The team confirmed during review of the 10 CFR Part 50, Appendix J, program that the program did test pressure retaining seals and gaskets. The other five exceptions related to difference between the ASME Section XI, Subsection IWE, requirements referenced in the GALL Report and newer ASME 2001 Code edition including the 2002 and 2003 Addenda that the applicant was required to meet. The applicant took the: (1) second exception because the ASME code no longer required that pressure-retaining bolting be disassembled or torque and tension tested; (2) third exception because Table IWE-2500-1 no longer contains seven examination categories; (3) fourth exception because Subsection IWE, Paragraphs IWE 2420(b) and (c) specified that flaws or areas of degradation accepted by an engineering evaluation shall be reexamined during the next inspection period and accepted if essentially unchanged, whereas the GALL Report specified three consecutive inspections; (4) fifth exception since the remaining categories in Table IWE-2500-1 all require 100 percent examination and there remained no need to expand the examination for any identified deficiency; and (5) sixth exception because the acceptance standards had been moved from Table IWE-3410-1 to Section IWE-3500.

For the ASME Section XI, Subsection IWE program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the containment liner, penetrations and integral attachments. The team concluded that, if implemented during each 10-year inservice inspection interval, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.11 B2.1.28 ASME Section XI, Subsection IWL (XI.S2)

The ASME Section XI, Subsection IWL program was an existing program, consistent with the GALL Report, credited with managing the aging effects of cracking, loss of material, and increase in porosity and permeability of the concrete containment building. The containment did not use a post-tensioning system. The applicant planned to manage the effects of aging by visually inspecting accessible portions of the concrete structure (including all of the concrete dome and cylinder walls).

The team reviewed applicable license renewal program basis documents, aging management review documents, the ASME Section XI, Subsection IWL program documents, and implementing procedures. The team discussed the relevant industry experience with plant personnel. The team confirmed that inspection procedures had personnel inspect for the following: (1) evidence of leeching or chemical attacks, (2) areas of corrosion, erosion, or abrasion, (3) evidence of scaling or disintegration, (4) deep gouges, spalls, popouts, or voids, (5) evidence of efflorescence, exudation, or incrustation, (6) blistering or peeling of coatings, and (7) exposed reinforcing steel. The procedures included acceptance criteria for documenting crack sizes and conditions requiring an evaluation.

The team identified a concern related to openings in the containment structure. As described in Final Safety Analysis Report Section 3.8.1.7, the applicant had installed strain gauges on selected rebar in the containment concrete. The applicant used these strain gauges during the initial structural integrity tests (Unit 1 - 1975; Unit 2 - 1977) to verify that the rebar responded as expected at various containment internal pressure levels. The team determined that the applicant had protected the strain gauges by covering them with a steel conduit box. The applicant routed the strain gauge wires from this conduit box inside flexible metal conduit to another conduit box on the outside of containment. The conduit box on the outside of containment was similar in size to a household electrical outlet box. After completing the structural integrity tests, the applicant abandoned the strain gauges. A note on Drawing 663075-657-01 states that a plastic plate covered the conduit box and silicone sealant was applied.

The team identified that the photographs from the most recent Subsection IWL inspection demonstrated that these outside boxes no longer maintained a watertight seal and corrosion was present. This strain gauge configuration might allow corrosion of the containment rebar since salt air and moisture may go through the outside box and conduit to the rebar. The team determined that the applicant had used silicone sealant around the plastic plate covering the exterior box. However, the team concluded that the applicant had neither evaluated the condition of the silicone sealant nor replaced the sealant in the last 30 years. The licensee had observed the condition of the outside surface of containment on a 10-year cycle and initiated actions to conduct the inspections on a 5-year frequency.

The applicant noted that no significant rebar corrosion existed since the Subsection IWL inspections of concrete did not indicate the presence of cracking or spalling near the strain gauges. The applicant evaluated this condition under Notification 50341635. The applicant established actions to enhance monitoring of the strain gauges and their cover plates for degraded conditions. Civil Engineering planned to issue a modification to correct the deficiency (including sealing up of the entire strain gauge wire box).

For the ASME Section XI, Subsection IWL program, the team concluded that, with exception of the issue identified above, the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the containment structure. The team concluded that, if implemented during each 10-year inservice inspection interval, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.12 B2.1.29 ASME Section XI, Subsection IWF (XI.S3)

The ASME Section XI, Subsection IWF program was an existing program, consistent with the GALL Report, credited with managing loss of material, cracking, and loss of mechanical function. For ASME Class 1, 2, and 3 piping and components and their associated supports, the applicant performed inspections consistent with the ASME 2001 Code edition including the 2002 and 2003 Addenda. The program conformed to Inspection Program B of ASME Section XI. The applicant completed 100 percent of the VT-3 visual examinations during every 10-year inspection interval.

The team reviewed applicable sections of the license renewal application, the NRC aging management program audit results, selected corrective action documents, operating experience, program procedures, and inspection procedures. The team also interviewed the program engineers. The team reviewed a sample of the listed inspections in the attachment from the Unit 1 1R15 refueling outage summary report. During plant tours, the team observed the condition of the facility including component supports required by this program.

The inspections examined the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements. The program required inspection of the following aspects of component supports: (1) deformations or structural degradations of fasteners, springs, clamps, or other support items, (2) missing, detached, or loosened support items, (3) arc strikes, weld splatter, paint scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces, (4) improper hot or cold setting of spring supports and constant loads, (5) misalignment of supports, and (6) improper clearances of guides and stops.

For the ASME Section XI, Subsection IWF program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the ASME Class 1, 2, and 3 components and supports. The team concluded that, if implemented during each 10-year inservice inspection interval, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.13 B2.1.30 10 CFR Part 50, Appendix J (XI.S4)

The 10 CFR Part 50, Appendix J program was an existing program, consistent with the GALL Report, credited with managing loss of material, loss of leak tightness, and loss of sealing. The program monitored leakage rates through the containment pressure boundary, including the electrical penetrations and access hatch openings, in order to detect degradation of the containment pressure boundary. The team determined that the mechanical penetrations had welds instead of pressure retaining seals. This aging management program included the steel containment liner and its integral attachments, as well as welds, gaskets, seals, and bolted connections for the primary containment pressure boundary. The team determined that the applicant would continue to perform leak rate testing during the period of extended operation to monitor leakage rates.

The team reviewed applicable parts of the license renewal application, the NRC aging management program audit results, corrective action documents, program assessments, and applicant responses to requests for additional information. The team reviewed the Unit 1 integrated leak rate test results completed after replacing the steam generators (Refuel Outage 1R14) and the local leak rate test for Penetration 68. Since the leak rate test program was performance-based, the applicant performed integrated leak rate tests on a 10-year frequency and performed Type B and Type C at their allowable frequencies. The program owner demonstrated detailed knowledge of the test requirements including the exceptions allowed by Appendix J.

The team confirmed that the 10 CFR Part 50, Appendix J program leak tested the seals and gaskets specified in their ASME Section XI, Subsection IWE program. The ASME Section XI, Subsection IWE program took an exception to the GALL Report to credit this program for testing seals and gaskets penetrating the containment liner. However, the team determined the aging management program evaluation report and the aging management program description in the license renewal application did not identify that the 10 CFR Part 50, Appendix J program tested seals and gaskets required by the ASME Section XI, Subsection IWE program. The applicant agreed to modify the program descriptions and documented this issue in Notification 50341877.

For the 10 CFR Part 50, Appendix J program, the team concluded that the applicant had performed appropriate evaluations of existing plant conditions and considered pertinent industry experience and plant operating history to determine the effects of aging on the primary containment. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.14 B2.1.31 Masonry Wall (XI.S5)

The Masonry Wall program was an existing program, consistent with the GALL Report, credited with managing cracking of masonry walls and structural steel restraint systems for masonry walls. The Masonry Wall program used guidance contained in the Maintenance Rule structures monitoring program. The Masonry Wall program contained visual inspection guidelines listing aging attributes (such as cracking, missing/broken blocks, or deteriorated penetrations) and established examination criteria, evaluation requirements, and acceptance criteria.

The team reviewed the applicable license renewal program basis documents, aging management program documents, plant procedures, and prior inspection results. In addition, the team searched the corrective action database for relevant action requests and evaluated the use of industry information. The team discussed the program with civil and program engineers and visually examined accessible masonry block walls to assess the condition. The team determined that the applicant had developed effective procedures to track changes to masonry wall conditions and had performed inspections to substantiate the masonry wall analyses and classifications. The licensee did not have any enhancements or exceptions to the GALL guidance.

The applicant planned to revise the program to require following the requirements of American Concrete Institute 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and American Concrete Institute 201.1R-08, "Guide for Conducting a Visual Inspection of Concrete in Service," which provided information related to conducting visual inspections of concrete in service. The team determined that the applicant will conduct the masonry block wall inspections at the same frequency required by the Maintenance Rule program during the period of extended operation.

For the Masonry Wall program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on masonry walls and supports. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.15 B2.1.32 Structures Monitoring (XI.S6)

The Structures Monitoring program was an existing program, consistent with the GALL Report after enhancement, credited with managing cracking, loss of material, and change in material properties of concrete structures and structural supports. The applicant included the following structures within the scope of this program: auxiliary building (including the control room), containment structure, turbine building, radwaste storage facilities, pipe-way (underground pipe tunnel) structure, fuel handling building steel superstructure, commodity supports and anchorages, outdoor tanks and foundations, buried structural commodities, electrical structures and foundations, and water control structures. The Structures Monitoring program provided inspection guidelines for concrete elements, structural steel, masonry walls, structural features (e.g., caulking, sealants, roofs, etc.), structural supports, and miscellaneous components such as doors. The Structures Monitoring program also monitored settlement of each major structure and inspected supports for equipment, piping, conduit, cable tray, metal-enclosed bus, heating ventilation and air conditioning, and instrument components.

The team reviewed the applicable license renewal program basis documents, aging management review documents, and existing procedures. The team searched the corrective action database for relevant action requests and evaluated the applicant's evaluation of operating experience. The team interviewed system and civil engineers involved with performing the inspections and conducted detailed system walk downs. The applicant used guidance contained in Procedures MA1.NE1, "Maintenance Rule Monitoring Program – Civil Implementation," Revision 3, AWP E-016, "Inspection Guidelines for the Maintenance Rule Monitoring Program – Civil Implementation," Revision 4, and MA1.ID17, "Maintenance Rule Monitoring Program," Revision 21.

The applicant planned to enhance the program to meet the GALL Report by revising plant procedures to monitor groundwater for pH, sulfates, and chloride concentrations, including consideration for potential seasonal variations, prior to the period of extended operation and every 5 years thereafter. Also, the applicant planned to revise plant procedures to inspect trash bar racks and associated structural components in the intake structure.

For the Structures Monitoring program, the team determined that the applicant had implemented and performed appropriate evaluations of structures. Further, the applicant had considered pertinent industry experience and plant operating history to determine the effects of aging on plant structures and structural commodities. The team concluded that, if implemented as described, the applicant would have provided adequate guidance to identify and address aging effects during the period of extended operation.

.16 <u>B2.1.33 Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"</u>

The Regulatory Guide 1.127 program was an existing program, consistent with the GALL Report, credited with managing cracking, loss of material, loss of form, loss of bond, loss of strength, and increase in porosity and permeability resulting from extreme environmental conditions and the effects of natural phenomena. The applicant implemented this program as part of the Structures Monitoring program. Although the applicant was not committed to Regulatory Guide 1.127 as part of their current licensing basis, the applicant followed the recommendations from the regulatory guide for inspection frequency and monitored all the in-scope components described in Regulatory Guide 1.127. For example, the applicant inspected the intake structures on a 5-year frequency consistent with Regulatory Guide 1.127, instead of the 10-year frequency specified by their maintenance rule program. The program included the following structures: intake structure, discharge structure, circulating water conduits, earth slopes over the auxiliary saltwater pipes, east and west breakwaters, and the raw water reservoirs.

The team reviewed the applicable license renewal program basis documents, aging management program documents, plant procedures, and prior inspection results. In addition, the team searched the corrective action database for relevant action requests and evaluated the use of industry information. The team discussed the program with civil and program engineers and visually examined accessible portions of the intake control structures to assess their condition. The team determined that the applicant had developed effective procedures to inspect and monitor the conditions of the water control structures and had performed inspections to demonstrate that they maintained the water control structures consistent with guidance contained in American Concrete Institute 349.3R-96 and American Society of Civil Engineers-11-90, "Guidelines for the Structural Condition Assessment of Existing Buildings," dated January 1990.

For the Regulatory Guide 1.127 program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on water control structures. The team concluded that, if implemented as described in the applicant's aging management program, the applicant would appropriately identify and address aging effects during the period of extended operation.

.17 B2.1.36 Metal-Enclosed Bus (XI.E4)

The Metal-Enclosed Bus program was an existing program, consistent with the GALL Report after enhancement, credited with managing the aging affects associated with loosening of bolted bus bar connections and reduced insulation and insulator resistance on bus ducts. Metal-enclosed buses were electrical buses installed on electrically insulated supports enclosed in a metal duct. The parameters monitored include connection tightness, embrittlement, cracking, melting, swelling or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports. The program scope included bus sections that were specifically required for station blackout recovery and other metal-enclosed bus sections whose failure could affect the station blackout recovery.

The team reviewed applicable license renewal program basis documents, aging management review documents, existing and new procedures, plant specific operating experience, and preventive maintenance requirements. The team interviewed the license renewal project personnel and the responsible plant and design engineers. The team walked down all the in-scope non-segregated bus and isolated-phase bus ducts.

The applicant will check accessible bolted connections of the in-scope metal-enclosed buses for evidence of overheating prior to the period of extended operation and every 10 years thereafter. The applicant planned to perform contact resistance tests or infrared thermography on the accessible connections. As an alternative to the thermography or measuring connection resistance of accessible bolted connections covered with insulating material, the applicant could elect to visually inspect insulation for surface anomalies, such as discoloration, cracking, chipping or surface contamination. If the applicant performs visual inspections, the applicant must complete the first inspection prior to the period of extended operation and every 5 years thereafter.

The applicant planned to enhance the Metal-Enclosed Bus program by creating a formal procedure rather than relying on periodic work orders to monitor the metal-enclosed buses for aging effects. The applicant indicated the procedure would specify the activities required to inspect and test the metal-enclosed buses, including the inspection scope, frequencies, and actions to be taken when acceptance criteria were not met.

The applicant had developed several procedures, as listed in the attachment, to monitor the condition of their metal-enclosed buses in response to their site-specific operating experience. Because the applicant implemented their infrared thermography activities as predictive maintenance monitoring, Procedure MPE-101A, "Infrared Thermography Inspections," Revision 6, specifically identified that the inspection results did not constitute quality records. The team concluded the procedure provided inappropriate guidance regarding the record retention requirements for thermography results related to in-scope component license renewal activities. The team determined these specific thermography results will be quality records since they would be used to demonstrate that the connections remained tight and had no adverse aging effects. The applicant updated Notification 50333175 to document the need to correct this procedure deficiency. The applicant indicated that they would include this required procedure change in the Project Plan for License Renewal Implementation.

The team reviewed plant-specific operating experience, which confirmed the need to perform aging management activities on metal-enclosed buses. The applicant had experienced several independent failures of their metal-enclosed buses related to: Noryl® insulation aging; cracked welds on 25 kV iso-phase bus neutral enclosures; cracked, corroded, or loose 4 kV bus supports; and faults on the 12 kV bus. The applicant had repaired the respective buses following each failure. The applicant replaced aluminum bus with copper bus, added Belleville washers to bolted connections, performed bus cleaning, initiated periodic micro-ohm testing, and re-torqued bolts. In addition, the applicant identified aging effects on Noryl® insulated buses and replaced the insulation as part of the existing corrective action program. The team verified that the applicant had replaced all aluminum non-segregated buses associated with station blackout recovery with copper buses.

For the Metal-Enclosed Bus program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the metal enclosed non-segregated bus ducts and metal-enclosed isolated-phase bus ducts. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.18 <u>B2.1.38 Transmission Conductor, Connections, Insulators and Switchyard Bus and Connections</u>

The Transmission Conductor, Connections, Insulators and Switchyard Bus and Connections program was an existing plant-specific program, which has no comparable GALL Report aging management program. The applicant credited this program with managing aging effects related to: insulator, conductor, connector and support degradation including corrosion, mechanical wear, and contamination; and conductor degradation including conductor strand breakage, excessive corrosion and swelling. The program considered the technical information provided in Electric Power Research Institute 1001997, “Parameters that Influence the Aging and Degradation of Overhead Conductors.” The applicant included both 230 kV and 500 kV switchyard structures and components required for station blackout recovery in this aging management program.

The team reviewed applicable license renewal program basis documents, aging management review documents, existing and new procedures, and preventive maintenance requirements. The team interviewed the license renewal project personnel and the responsible engineers. The team walked down the in-scope 230 kV and 500 kV switchyards, transmission lines, conductors, structures, disconnects, breakers, switchyard buses and connections.

Prior to the period of extended operation, the applicant planned to enhance the existing program by: (1) issuing a plant procedure that defined the program scope, responsibilities, objectives, and inspection activities required for components within the scope of license renewal; (2) requiring personnel to gather and review completed maintenance and inspection results to identify any adverse trends, and (3) requiring engineering to evaluate any detected degraded conditions and consider the extent of condition, reportability, potential root causes, probability of recurrence, and the corrective actions required.

The applicant inspected switchyard components related to their overhead transmission systems. The inspections met the state guidelines for overhead transmission lines to ensure public safety and reliability. This program required that all 230 kV and 500 kV transmission lines be inspected by performance of aerial, ground, and climbing inspections at specified frequencies. The inspections look for, but were not limited to, insulator, conductor, connector, and support degradation including corrosion, mechanical wear, and contamination. Conductors were also monitored for indications of degradation including strand breakage, excessive corrosion, and swelling. The applicant documented, evaluated, and trended the inspection results.

In addition to the inspections, the applicant hot washed the 500 kV high voltage insulators on a 6-week frequency to remove salt spray contamination and inspected 230 kV and 500 kV insulators annually to verify connectivity using ground or overhead infrared thermography inspections. The applicant had replaced all insulators on the 230 kV and 500 kV transmission lines between the plant and the switchyard dead end structures (transmission line termination points) in 1999 and 2000. In addition, the applicant had replaced any individual insulator that had experienced a fault or had degraded insulation.

Based on observations by the team during the switchyard walk down, the applicant generated Notification 50341749 to address cracking identified in concrete and grout, a bent structural member, discoloration of an insulator bell, and rust on some connectors. During review of the license renewal application, the team identified an error in the designator for the for the in-scope switchyard breakers. The applicant had listed the numbers for the switchyard disconnects. The applicant issued to Notification 50341482 to have the application corrected.

For the Transmission Conductor, Connections, Insulators and Switchyard Bus and Connections program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for inaccessible cables. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

b.4 System Reviews

For selected plant systems within the scope of license renewal, the team performed a vertical slice review of the applicant's scoping, screening, and aging management reviews of selected components to confirm whether the applicant accurately determined the appropriate material and environment and correctly assigned the appropriate aging management programs.

The team selected the following systems for review:

- Auxiliary feedwater
- Diesel engine generator
- Compressed air

The team interviewed the license renewal staff members and the system engineers responsible for the auxiliary feedwater, diesel engine generator, and the compressed air systems. The team: (1) selected components and verified material specifications; (2) walked down the systems to confirm that the applicant had properly identified scoping boundaries (including structural and spatial interactions); identified the environments affecting the systems and had properly identified aging management programs to manage the effects of aging for these systems; and (3) evaluated the physical condition of the sampled systems. The team met with license renewal staff to determine how the applicant identified the applicable aging effects and assigned the applicable aging management program for each structure, system, or component.

For the auxiliary feedwater system, the aging effects requiring management included loss of material, loss of preload, and reduction of heat transfer. The applicant credited the following aging management programs for managing the identified aging effects: Water Chemistry, Bolting Integrity, one-time inspection, External Surfaces Monitoring, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Lubricating Oil Analysis programs. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

For the diesel engine generator system, the aging effects requiring management included cracking, loss of material, loss of preload, and reduction of heat transfer. The applicant credited the following aging management programs for managing the identified aging effects: Closed Cycle Cooling Water System, Fuel Oil Chemistry, Bolting Integrity, one-time inspection, External Surfaces Monitoring, Inspection of Internal Surfaces in

Miscellaneous Piping and Ducting Components, and Lubricating Oil Analysis programs. With the exception of the items below, the team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

The team identified that the applicant had incorrectly classified the material of a magnetic pump, which was used to keep positive pressure on the fuel injectors, as being made of polyvinyl chloride. The pump material was Ryton® (a trade name for a specific type of thermoplastic). Ryton® had much higher melting and operating temperature characteristics than polyvinyl chloride and was therefore more suitable for the intended application. The applicant initiated Notification 50341911 to evaluate the classification of this material and determine whether to revise their license renewal application. Neither polyvinyl chloride nor Ryton® had any known adverse affects by exposure to the fuel oil or the atmosphere air in which the pump operated. The GALL Report identified no aging management for polyvinyl chloride, Ryton® or other thermoplastics. The team looked at the extent of condition and identified no additional examples of misclassification of polyvinyl chloride materials.

For the compressed air system, the aging effects requiring management included loss of material resulting from corrosion and loss of preload on closure bolting. The applicant credited the following aging management programs for managing the identified aging effects: Water Chemistry, Bolting Integrity, One-Time Inspection, Selective Leaching of Materials, External Surfaces Monitoring, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components. With the exception of the items below, the team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

During a plant walk down, the team questioned whether the diesel generator starting air compressors should have copper or stainless steel unloader tubing since the team noted both materials installed. The applicant responded that either material could be used and demonstrated that mechanics look for the presence of corrosion during shop repairs. While responding to this question, the applicant determined that they had failed to consider the material-environment combination for the copper tubing in their license renewal application. From a review of a revised license renewal application section, the team confirmed that, although the application had an error, no aging effects required managing for the copper-to-indoor air material environment combination.

The team identified two concerns after walking down accessible portions of the compressed air system. The first concern related to the presence of high-pressure flexible hoses and connections from local compressed air bottles to the atmospheric dump valves. The applicant had not included these hoses in any aging management program. The applicant initiated Notification 50336850 on this issue. The Strategic Teaming and Resource Sharing Center of Business initiated CCAP 2010-0143 noting this issue and other issues related to the compressed air system. The applicant stated that they intend to establish a preventive maintenance task to replace the flex hoses so that they would be considered short-lived components.

The team also found that Regulator AIR-I-I-1231A was not aluminum as specified in the aging management program but was some type of copper alloy. The applicant initiated

Notification 50341879 to verify the material and provide the required information as part of the annual update of the license renewal application.

For these systems, the team concluded that the physical condition of the system and the results of tests and inspections of the various existing aging management programs demonstrated that materials, environments, and aging effects on the selected systems had been appropriately identified and addressed, except as discussed above. Further, the team concluded that the applicant appropriately addressed the aging effects for these systems with the identified aging management programs, with the exceptions described above.

b.5 Significant Replacement Activities

The team reviewed information concerning significant replacement activities that placed the units in a better material condition prior to entering the period of extended operation:

- Replacing steam generators in both units (completed)
- Replacing reactor vessel heads in both units (completed)
- Repairs to the concrete at the intake structure (in progress)
- Replacing 4 kV cables (completed)

The replacement of these major items corrected many items addressed by aging management program and resulted in eliminating any residual aging effects.

In addition, the team determined that the applicant had initiated actions to develop a long term, detailed plan for incorporating activities required for license renewal into their daily current license basis activities.

c. Overall Conclusion

Overall based on the samples reviewed by the team, the inspection results supported a conclusion that there is reasonable assurance that actions have been identified and have been taken or will be taken to manage the effects of aging in the SSCs identified in your application and that the intended functions of these SSCs will be maintained in the period of extended operation.

40A6 Meetings, Including Exit

The team presented the inspection results to Mr. L. Sharp, Engineering Services Senior Director, and other members of the applicant's staff during an exit meeting conducted on September 16, 2010. The applicant acknowledged the NRC inspection observations. The team returned all proprietary information reviewed during this inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

Diablo Canyon License Renewal Documents Reviewed

KEY POINTS OF CONTACT

<u>Applicant</u>

J. Anastasio, Auxiliary Saltwater System Engineer
L. Alves, Electrical Maintenance
C. Beard, Metallurgist
K. Braico, Licensing Engineer
R. Davis, Licensing Engineer
K. Duke, Licensing Engineer
D. Efron, Mechanical System Engineer
J. Fleddermon, Strategic Projects Director
M. France, Supervising Engineer
H. Garcia, Seismically Induced Systems Interaction Program Engineer
R. Gardner, Chemistry Supervisor
D. Gibbons, Licensing Engineer
L. Goyette, Principle Mechanical Engineer
T. Grebel, Project Manager
J. Hill, Inservice Inspection Engineer
G. Holtz, Containment Leak Rate Test Program Engineer
T. Juarez, System Engineer
T. Lee, Civil Design Engineer
A. Maple, Auxiliary Feedwater System Engineer
D. Miklish, License Renewal Consulting Engineer
K. Morris, Electrical Maintenance
M. Munoz, Substation System Engineer
L. Price, Diesel Fuel System Engineer
T. Smith, Pismo Substation Maintenance Superintendent
L. Sharp, Engineering Services Senior Director
P. Soenen, License Renewal Assistant Project Manger
C. Sorensen, Inservice Inspection Program Engineer
M. Tan, Licensing Engineer
E. Wessel, Plant Chemist
S. Westcott, Director Engineering Services
D. Wong, Supervising Civil Engineer
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S. Gardocki, Reactor Systems Engineer, Balance of Plant Branch, Office of Nuclear Reactor Regulation

General

Letters

DCL-10-057, "Response to NRC Request for Additional Information for the Diablo Canyon License Renewal Application," dated June 3, 2010

DCL-10-067, "Response to License Renewal Application (LRA) Request for Additional Information and LRA Errata," dated June 18, 2010

DCL-10-073, "Response to NRC Request for Additional Information for the Diablo Canyon License Renewal Application," dated July 7, 2010

DCL-10-076, "Response to NRC Letter dated June 29, 2010, Request for Additional Information (Set 6) for the Diablo Canyon License Renewal Application," dated July 15, 2010

DCL-10-077, "Response to NRC Letter dated June 21, 2010, Request for Additional Information (Set 5) for the Diablo Canyon License Renewal Application," dated July 19, 2010

DCL-10-091, "Response to NRC Letter dated June 18, 2010, Request for Additional Information (High Energy Piping) for the Diablo Canyon License Renewal Application," dated July 28, 2010

DCL-10-092, "Response to NRC Letter dated July 6, 2010, Request for Additional Information (Set 7) for the Diablo Canyon License Renewal Application," dated July 28, 2010

DCL-10-096, "Response to NRC Letter dated July 14, 2010, Request for Additional Information (Set 8) for the Diablo Canyon License Renewal Application," dated August 12, 2010

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

DCL-10-098, "Response to NRC Letter dated July 15, 2010, Request for Additional Information (Set 10) for the Diablo Canyon License Renewal Application," dated August 12, 2010

DCL-10-100, "Response to NRC Letter dated July 20, 2010, Request for Additional Information (Set 11) for the Diablo Canyon License Renewal Application," dated August 17, 2010

DCL-10-101, "Response to NRC Letter dated July 20, 2010, Request for Additional Information (Set 12) for the Diablo Canyon License Renewal Application," dated August 17, 2010

DCL-10-104, "Response to NRC Letter dated July 20, 2010, Request for Additional Information (Set 13) for the Diablo Canyon License Renewal Application," dated August 17, 2010

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

DCL-10-107, “Response to NRC Letter dated July 22, 2010, Request for Additional Information (Set 14) for the Diablo Canyon License Renewal Application,” dated August 18, 2010

DCL-10-113, “Response to NRC Letter dated August 3, 2010, Request for Additional Information (Set 16) for the Diablo Canyon License Renewal Application,” dated August 30, 2010

DCL-10-116, “Response to NRC Letter dated August 9, 2010, Request for Additional Information (Set 18) for the Diablo Canyon License Renewal Application,” dated September 7, 2010

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

License Renewal Documents (reviewed as needed by team members)

Operating Experience Action Request Summary Reports

Operating Experience Summary Reports

Operating Experience Industry Experience Summary Reports

License Renewal Component Lists

Diablo Canyon License Renewal Application, including Appendices A, “Final Safety Analysis Report Supplement,” and B, “Aging Management Programs”

Procedures (reviewed as needed by team members)

AD1, “Administrative Controls Program,” Revision 15

OM4, “Assessment of Industry Operating Experience,” Revision 15

OM5, “Quality Assurance Program,” Revision 5A

OM7, “Corrective Action Program,” Revision 4

Miscellaneous

Audit Report Regarding the Diablo Canyon Nuclear Power Plant License Renewal Application (TAC NOS. ME2896 AND ME2897), dated August 11, 2010

Desktop Guide DG-6, “License Renewal Boundary Drawings,” Revision 0

LR-ISG-2007-02, “Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, ‘Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements’”

Nuclear Energy Institute 95-10, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule,” Revision 6

NUREG-1801, “Generic Aging Lessons Learned (GALL) Report – Summary,” Volume 1, Revision 1

NUREG-1801, “Generic Aging Lessons Learned (GALL) Report – Tabulation of Results,” Volume 2, Revision 1

NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” Revision 1

Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses,” Revision 1

Notifications

50335150	50335151	50335153	50335156	50335297	50335373
50335377	50335379	50335450	50335451	50341711	50341755

Topical Reports

TR-2DC, “Station Blackout (SBO) - License Renewal Feasibility Study Position Paper,” Revision 2

TR-3DC, “Fire Protection - License Renewal Position Paper,” Revision 1

TR-6DC, “Criterion (a)(2) - License Renewal Feasibility Study Position Paper,” Revision 1

TR-7DC, “Electrical/I&C Plant Spaces Approach - License Renewal Feasibility Study Position Paper,” Revision 1

TR-8DC, “Aging Effects Topical Report,” Revision 2

Procedure TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0

TR-11DC, “Electrical Component Aging Evaluations - License Renewal Topical Report,” Revision 0

TR-12DC, “Design Basis Events - License Renewal Feasibility Study Position Paper,” Revision 1

TR-13DC, “Specifications and Standards - License Renewal Feasibility Study Position Paper,” Revision 0

Scoping

Control Room Pressurization System

Drawing 501418, “Turbine Building Area ‘A’ Plan Elevation 119’-0”,” Revision 7

Drawing 511155, “Plan and Sections – Air Conditioning Control Room Pressurization Fan Arrangements Area ‘A’ Elevation 140’-0”,” Revision 16

Photographs of control room pressurization system components on turbine deck

Drawings - Fuel Oil Pump Vaults and Structures

438037, “Foundation Details for Diesel Fuel Oil Storage Tanks,” Revision 5

438165, “Emergency Diesel Generator Fuel Oil System,” Revision 14

438166, “Diesel Fuel Pump Vaults,” Revision 15

438172, “Yard General Utilities,” Revision 21

463667, “Structural Modifications Diesel Fuel Pump Vaults,” Revision 8

463987, “Exterior Concrete Tank Protection,” Revision 25

465173, “Condensate Polishing System Discharge Piping & Transfer Sumps Turbine Building,” Revision 10

508845, “Diesel Fuel Oil Transfer Pump Vaults,” Revision 13

4016302, “Diesel Fuel Storage Tank 0-1 Installation & Miscellaneous Plan, Details & Sections,” Revision 1

4016304, “Diesel Fuel Storage Tank 0-2 Miscellaneous Sections,” Revision 1

4016309, “Diesel Fuel Storage Tank 0-2 Installation & Miscellaneous Plan, Details & Sections,” Revision 1

4016311, “Diesel Fuel Storage Tank 0-2 Miscellaneous Sections,” Revision 1

6015743-1-1, “250,000 Gallon Underground Fuel Storage Tank Construction Details,” Revision 4

Drawings – Intake Structure

438076, “Cathodic Protection Details Intake Structure,” Revision 9

498107, “Electrical Cathodic Protection System Auxiliary Saltwater Circulating Water Conduits and Intake Structure,” Revision 6

500696, “Cathodic Layout Intake Structure,” Revision 8

500823, “Grounding Layout Intake Structure,” Revision 7

501731, “Cathodic Protection Main Intake Structure & Screen Wash Pump Area,” Revision 5

503103, “Cathodic Protection Main Intake Structure & Screen Wash Pump Area,” Revision 4

Miscellaneous

NRC Audit Report Regarding the Diablo Canyon Nuclear Power Plant License Renewal Application – Scoping and Screening Methodology, dated July 16, 2010

Drawing 437677, “Schematic Diagram Oily Water Separator & Turbine Building Sump Pumps,” Revision 18

Notification 50341848

Project Instruction PI-1, “Scoping and Screening of Systems, Structures, and Components for STARS License Renewal Projects,” Revision 4

Report of Joint Strategic Teaming and Resource Sharing-Diablo Canyon Power Plant License Renewal Walk-down, dated March 5, 2010

Request for Additional Information Related to the Review of the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application – Scoping and Screening Methodology, dated May 24, 2010

Request for Additional Information Related to the Review of the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application – Scoping and Screening and Aging Management Review, dated July 15, 2010

Request for Additional Information Related to the Review of the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application – Scoping and Screening, dated July 20, 2010

Request for Additional Information Related to the Review of the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application – Scoping and Screening and Aging Management Review, dated August 9, 2010

Set of License Renewal Drawings

Notifications

50313965 50341482 50341848

Service Cooling Water System

57718, “Equipment Location Plan at Elevation 85’-0” Turbine Building,” Revision 37

57719, “Equipment Location Plan at Elevation 104’-0” Turbine Building,” Revision 14

57720, “Equipment Location at Elevation 119’-0” Turbine Building,” Revision 17

57721, “Equipment Location at Elevation 140’-0” Turbine Building,” Revision 21

515562, “Fire Barriers, Zones and Fixed Suppression/Detection Turbine Building Elevation 85’-0”,” Revision 16

515563, “Fire Barriers, Zones and Fixed Suppression/Detection Turbine Building Elevation 104’-0”,” Revision 12

515564, “Fire Barriers, Zones and Fixed Suppression/Detection Turbine Building Elevation 119’-0”,” Revision 12

515565, “Fire Barriers, Zones and Fixed Suppression/Detection Turbine Building Elevation 140’-0”,” Revision 12

New Programs

B2.1.16 One-Time Inspection (XI.M32)

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.16, “One-Time Inspection – B2.1.16,” Revision 3

One-Time Inspection Operating Experience White Paper, Revision 0

Miscellaneous

Notification 50341874

One-Time Inspection Sample Basis Document, Revision 0

Request for Additional Information B2.1.16-1 and applicant response

Request for Additional Information B2.1.16-2 and applicant response

Procedure TS1.ID12, “One-Time Inspection Program,” Revision 0

B2.1.17 Selective Leaching of Materials (XI.M33)

Action Requests

A0350059 A0438773

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.17, “Selective Leaching of Materials – B2.1.17,” Revision 3

Selective Leaching Operating Experience White Paper, Revision 5

Miscellaneous

Notifications 50123904 and 50341752

Procedure TS1.ID11, “Selective Leaching Degradation Program,” Revision 0

Request for Additional Information B2.1.17-1 and applicant response

B2.1.18 Buried Piping and Tanks Inspection (XI.M34)

Action Requests

A0350059 A0431200 A0438773 A0442225 A0460974

Drawings

57723, “Auxiliary and Containment Buildings Plan at Elevation 73’-0”,” Revision 16

57724, “Auxiliary and Containment Buildings Plan at Elevation 85’-0”,” Revision 28

57729, “Auxiliary and Containment Buildings Section B-B,” Revision 15

57730, “Auxiliary and Fuel Handling Buildings Section C-C,” Revision 13

438164, “Auxiliary Saltwater Discharge Piping,” Revision 7

438166, “Diesel Fuel Pump Vaults,” Revision 15

508845, “Diesel Fuel Oil Transfer Pump Vaults,” Revision 13

4005077, “Saltwater System Isometric Auxiliary Saltwater Outlet Piping,” Revision 2

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.18, “Buried Piping and Tanks Inspection – B2.1.18,” Revision 3

Buried Piping and Tanks Program Operating Experience - White Paper, Revision 3

Miscellaneous

Cathodic Protection System - White Paper, Revision 0

Electric Power Research Institute Report 1016456, “Recommendations for an Effective Program to Control the Degradation of Buried Pipe,” dated December 2008

Groundwater – White Paper, Revision 0

Life Cycle Management of Buried Pipe – Structural Integrity Report-03-010, dated February 2010

Nuclear Energy Institute 09-14, “Guideline for the Management of Buried Pipe Integrity,” dated January 2010

NUREG/CR-6876, “Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants,” dated June 2005

Notifications

50286561 50297724

Procedures

MP E-72.1, “Cathodic Protection Monitoring System,” Revision 7

MP E-72.2, “Monthly Cathodic Protection Monitoring System,” Revision 10

PEP-72.1, “Annual Survey of ASW Cathodic Protection,” Revision 0

TS5.ID3, “Buried Piping and Tanks Program,” Revision 1

B2.1.20 External Surfaces Monitoring Program (XI.M36)

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.20, “External Surfaces Monitoring Program – B2.1.20,” Revisions 1 and 2

External Surfaces Monitoring Operating Experience White Paper, Revision 6

Miscellaneous

Notification 50335453

Procedure TS5.ID1, “System Engineering Handbook,” Revisions 14 and 15

B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E1)

Action Requests

A0476872 A0477291 A0477350 A0477593

License Renewal

Aging Management Program Evaluation Report DCPP-AMP- B2.1.24, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” Revision 4

Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Operating Experience White Paper, Revision 1

Miscellaneous

1205-2000, “IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations”

Electric Power Research Institute Report 109619, “Guide for the Management of Adverse Localized Equipment Environments,” dated June 1999

Electric Power Research Institute Report 1013475, “Plant Support Engineering: License Renewal Electrical Handbook – Revision 1 to EPRI Report 1003057,” dated February 2007

Procedure TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0J

Topical Report TR-11DC, “Electrical Component Aging Evaluations - License Renewal Topical Report,” Revision 0

B2.1.35 Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E6)

Action Requests

A0472235 A0547811 A0563486

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.35, “Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” Revision 3

Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Operating Experience White Paper, Revision 1

Miscellaneous

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Electric Power Research Institute Report 109619, “Guide for the Management of Adverse Localized Equipment Environments,” dated June 1999

Electric Power Research Institute Report 1013475, “Plant Support Engineering: License Renewal Electrical Handbook – Revision 1 to EPRI Report 1003057,” dated February 2007

LR-ISG-2007-02, “Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, ‘Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements’”

Notification 50198804

Procedure TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0J

SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations,” dated September 1996

Topical Report TR-11DC, “Electrical Component Aging Evaluations - License Renewal Topical Report,” Revision 0

Existing Programs

B2.1.2 Water Chemistry

Action Requests

A0433758	A0455772	A0480067	A0646546	A0646547	A0648386
A0676632	A0730219	A0734403			

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.2, “Water Chemistry,” Revision 2

Water Chemistry Operating Experience White Paper, Revision 6

Miscellaneous

2005, 2007 and 2009 Chemistry and Radiochemistry Program Audits

Electric Power Research Institute 1014986, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” Volumes 1 and 2, Revision 6

Electric Power Research Institute 1016555, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 7

Equipment Control Guideline 7.4, “Reactor Coolant Chemistry”

Strategic Primary Water Chemistry Plan, Revision 3

Strategic Secondary Water Chemistry Plan, Revision 7

Nonconformance Reports

N0002084 N0002129

Notifications

50043561 50076930 50233661

Procedures

CAP A-1, “Primary Sampling and Analysis Schedules,” Revision 22

CAP A-2, “Secondary Sampling and Analysis Schedules,” Revision 21

CAP A-3, “Technical Specifications Sampling Schedule,” Revision16

CAP E-1,”Primary Systems Sampling,” Revision 48

CAP E-6,”Secondary Systems Sampling,” Revision 12

CY1, “Chemistry/Radiochemistry,” Revision 2

CY1.DC1, “Analytical Data Processing Responsibilities,” Revision 5

OP F-5:I, “Chemical Control Limits and Action Guidelines for the Primary Systems,” Revision 38

OP F-5:II, “Chemical Control Limits and Action Guidelines for the Secondary Systems,” Revision 37

Quality Performance Assessment Reports

Second Period 2008

Third Period 2008

First Period 2009

Second Period 2009

Third Period 2009

First Period 2010

B2.1.4 Boric Acid Corrosion (XI.M10)

Action Requests

A0537774	A0686821	A0688061	A0691373	A0708660	A0713596
A0736999	A0738934	A0741811	A0741812	A0741814	A0741815
A0741816	A0741819	A0741820	A0741823	A0741824	A0741827
A0741846	A0741876	A0742001			

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.4, “Boric Acid Corrosion,” Revision 5

Boric Acid Corrosion Operating Experience White Paper, Revision 8

Miscellaneous

Assessment 032680010, “Boric Acid Corrosion Control Program (BACCP),” dated September 30, 2003

Assessment 070540002, “Followup Assessment of Boric Acid Corrosion Control Program,” dated February 23, 2007

Electric Power Research Institute 1000975, “Boric Acid Corrosion Guidebook,” Revision 1

Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants,” dated March 17, 1988

Letter DCL-88-143, Response to Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR [Pressurized Water Reactor] Plants,” dated June 2, 1988

List of current Boric Acid Leaks

Trending Results for B2.1.4, “Boric Acid Corrosion”

Notifications

50036555	50037231	50041579	50042190	50042581	50086294
50231056	50262445	50265736	50282971	50289936	

Procedures

AD4.ID2, “Plant Leakage Evaluation,” Revision 10

AD7.ID11, "Fluid Leak Management Program," Revision 0

ER1.ID2, "Boric Acid Corrosion Control Program," Revision 4

NDE VT 2-1, "Visual Examination During Section XI System Pressure Test," Revision 1

STP R-8A, "Reactor Coolant System Leakage Test," Revision 5

STP R-8C, "Containment Walkdown for Evidence of Boric Acid Leakage," Revision 90

Work Orders

60004783 60006516 60007079 60007435 60014700 60026988
68006850

B2.1.6 Flow-Accelerated Corrosion (XI.M17)

Action Requests

A0067324 A0070764 A0083834 A0084101 A0084268 A0148323

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.6, "Flow-Accelerated Corrosion," Revision 2

Flow-Accelerated Corrosion Operating Experience White Paper, Revision 2

Miscellaneous

Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," dated May 2, 1989

Letter DCL-87-217, "Response to NRC Bulletin No 87-01, Thinning of Pipe Walls," dated September 8, 1987

Letter DCL-89-192, "Response to Generic Letter 89-08, Erosion/Corrosion," dated July 19, 1989

NRC IE Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," dated July 9, 1987

Procedure TS1.NE1, "Flow-Accelerated Corrosion Monitoring Program," Revision 6

Self Assessment for Unit 2 Feedwater Piping Replacement, dated June 11, 2007

B2.1.9 Open-Cycle Cooling Water (XI.M20)

Action Requests

A0300684	A0324658	A0326711	A0333700	A0344037	A0381507
A0433036	A0446307	A0455471	A0516924	A0575609	A0585556
A0592354	A0607055	A0624997	A0625614		

Inspections

Intake Bay Inspection Summaries, dated September 29, 2009, and October 1, 2009

STP M-235A, “ASW Piping Inspection, CCW Heat Exchanger,” Unit 1, completed April 15, 2004

STP M-235A, “ASW Piping Inspection, CCW Heat Exchanger,” Unit 2, completed November 3, 2004

STP M-235B, “ASW Piping Inspection at Vacuum Breaker Vault,” Unit 1, completed April 15, 2004

STP M-235B, “ASW Piping Inspection at Vacuum Breaker Vault,” Unit 2, completed November 3, 2004

STP M-235C, “ASW Piping Inspection at Intake Structure,” Unit 1, completed April 15, 2004

STP M-235C, “ASW Piping Inspection at Intake Structure,” Unit 2, completed November 3, 2004

Letters

DCL 90-027, “Response to Generic Letter 89-13, ‘Service Water System Problems Affecting Safety-Related Equipment,’” dated January 26, 1990

DCL 91-286, “Supplemental Response to Generic Letter 89-13, ‘Service Water System Problems Affecting Safety-Related Equipment,’” dated November 25, 1991

DCL 94-037, “Auxiliary Saltwater System Operability,” dated February 15, 1994

DCL 94-174, “Reply to Notice of Violation in NRC Enforcement Action 94-056 (NRC Inspection Report Nos. 50-275/94-08 and 50-323/94-08),” dated August 4, 1994

License Renewal

Aging Management Program Evaluation Report DCPP-AMP- DCPP-AMP-B2.1.9, “Open Cycle Cooling Water System,” Revision 3

Open-Cycle Cooling Water Operating Experience White Paper, Revision 4

Miscellaneous

Auxiliary Saltwater System Health Reports, Units 1 and 2, 3rd Quarter 2009 through 2nd Quarter 2010

Component Cooling Water Heat Exchanger Test Summary

Design Criteria Memorandum S-17B, "Auxiliary Saltwater System," Appendix A, "ASW Bypass Modification and Criteria for ASW Bypass Buried Piping"

Electric Power Research Institute 1008282, "Life Cycle Management Sourcebook for Nuclear Plant Service Water Systems," dated March 2005

Equipment Control Guideline 17.2, "Auxiliary Saltwater Continuous Chlorination System"

NRC Inspection Report Nos. 50-275/93-36 and 50-323/93-36

Licensee Event Report 1-93-012-01, "Auxiliary Saltwater System Outside Design Basis Due to Fouling," dated March 8, 1994

Nonconformance Report N0001784

Report 420DC-05.8, "Remote Visual Inspection of the Diablo Canyon Power Plant, Unit 1, Auxiliary Saltwater Piping Train 1-1 and 1-2 during the 12th Refueling Outage (May 2004)," dated February 2005

Notifications

50032659	50199694	50201326	50359698

Procedures

AR PK01-01, "Unit 1(2) ASW SYS HX Delta P/HDR Press," Revision 21A(11A)

BIO D-4, "Collection and Analysis of Macrofouling Samples from the Component Cooling Water Heat Exchangers," Revision 0B

BIO D-5, "Microfouling Sample Collections in Component Cooling Water Heat Exchangers," Revision 0A

CAP E-4, "Auxiliary Saltwater Sampling," Revision 16

OP F-5:III, "Chemistry Control Limits and Action Guidelines for the Plant Support Systems," Revision 21

MA1.ID20, "Testing and Inspections for Aux Saltwater System NRC Generic Letter 89-13 Compliance," Revisions 1 and 2

PEP C-17.13, "Coatings Surveillance Program for the Saltwater Systems," Revision 1

PEP M-234, “CCW Heat Exchanger Performance Test,” Revision 11

STP M-26, “ASW System Flow Monitoring,” Revision 29

STP M-235A, “ASW Piping Inspection, CCW Heat Exchanger,” Revision 2

STP M-235B, “ASW Piping Inspection at Vacuum Breaker Vault,” Revision 2

STP M-235C, “ASW Piping Inspection at Intake Structure,” Revision 3

TS1.ID4, “Saltwater Systems Aging Management Program,” Revision 3

TS5.ID1, “System Engineering Program,” Revision 15

Surveillances – Pump (STP M-26, “ASW Flow Monitoring”)

R0308744	R0308673	R0310041	R0310104	R0311207	64108676
64018664	64021758	64022422	64036790	64039076	64039081
64042168					

Surveillances - Valve

STP M-26A, “FCV-601, ASW Unit 1 and Unit 2 Cross-tie Dividing Valve, Flow Test,” completed June 19, 2009

STP M-26A, “FCV-601, ASW Unit 1 and Unit 2 Cross-tie Dividing Valve, Flow Test,” completed December 30, 2007

B2.1.10 Closed-Cycle Cooling Water (XI.M21)

Action Requests

A0340549	A0367029	A0367417	A0375650	A0593710	A0603631
A0618445	A0632396	A0634936	A0642574	A0645890	A0646546
A0646770	A0647160	A0651244	A0664173	A0669006	A0689273
A0720656					

License Renewal

Aging Management Program Evaluation Report DCPP-AMP- DCPP-AMP-B2.1.10, “Closed-Cycle Cooling Water System,” Revisions 3 and 4

Closed-Cycle Cooling Water System Operating Experience White Paper, Revision 7

Miscellaneous

Closed Cooling Water Chemistry Basis Document, Revision 0

Closed Cooling Water Chemistry Strategic Plan, Revision 2

Closed Cooling Water Chemistry Trends

Closed Cooling Water Heat Exchanger Inspections

Component Cooling Water System Health Reports, Units 1 and 2, 3rd Quarter 2009 through 2nd Quarter 2010

Electric Power Research Institute NP 6815-D, “Detection and Control of Microbiologically Influenced Corrosion”

Electric Power Research Institute TR-107396, “Closed Cooling Water Chemistry Guideline,” Revision 0

Electric Power Research Institute 1007820, “Closed Cooling Water Chemistry Guideline,” Revision 1

Final Report Closed Cooling System Water Treatment Consulting, dated February 6, 2004

Letter NF-PGE-08-79, “Revision 1 – Post Elevated Lithium Operation Measured Versus Predicted Oxide Results,” dated September 4, 2008

NACE [National Association of Corrosion Engineers] International Publication 7G181, “Investigation of the Effects of Corrosion-Inhibiting Treatments on Mechanical Seals in Recirculating Hot Water Systems,” dated March 1997

System Training Guide – Auxiliary Saltwater

System Training Guide – Component Cooling Water

Technical Report 11-0218-00-TR-001, “Biological Fouling of Closed Cooling Water Systems,” Revision 0

Water Technology Article, *“Controlling Corrosion in Closed-Loop Systems,”* Volume 23, Issue 1, January 2000

Nonconformance Reports

N0001892	N0002196

Notifications

50033674	50034249	50036855	50051359	50057695	50313433
50341717	50341936				

Procedures

CAP A-9, “Auxiliary Systems Sampling Schedule,” Revision 30

CAP O-6, “Chemical Additions to Closed Cooling Water Systems,” Revision 19

CY1, “Chemistry/Radiochemistry,” Revision 2

CY1.DC1, “Analytical Data Processing Responsibilities,” Revision 5

CY1.ID2, “Closed Cooling Water Chemistry Program,” Revision 1

MA1.DC51, “Preventative Maintenance Program,” Revision 11

MA1.ID20, “Testing and Inspections for Aux Saltwater System NRC Generic Letter 89-13 Compliance,” Revision 1

MP M-51.14, “Generic Check Valve Inspection,” Revision 14

OP F-5:III, “Chemistry Control Limits and Action Guidelines for the Plant Support Systems,” Revision 21

PEP M-234, “CCW Heat Exchanger Performance Test,” Revisions 11 and 12

STP M-9A, “Diesel Emergency Generator Routine Surveillance,” Revision 79

STP M-21-ENG.1, “Diesel Engine Generator Inspection (Every Refueling Outage),” Revision 11

STP M-21-ENG.6, “Diesel Engine Generator Inspection (Every Sixth Refueling Outage),” Revision 1A

STP M-21-ENG.8, “Diesel Engine Generator Inspection (Every Eighth Refueling Outage),” Revision 2

TS5.ID1, “System Engineering Program,” Revision 15

Surveillance Tests

STP M-9A, “Diesel Emergency Generator Routine Surveillance,” completed for Diesel Generator 2-1 February 10, 2010

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STP P-CCW-11, “Routine Surveillance Test of Component Cooling Water Pump 1-1,” completed February 18, 2010

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STP P-CCW-13, “Routine Surveillance Test of Component Cooling Water Pump 1-3,” completed May 29, 2009

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STP P-CCW-23, “Routine Surveillance Test of Component Cooling Water Pump 2-3,” completed February 1, 2010

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R0226718	R0226719	R0252440	R0255373	R0277226	R0277230
64002671	64002672				

Work Orders – Diesel Engine Generator Overhaul

R0132843	R0132895	R0140317	R0140318	R0147233

B2.1.13 Fire Water System (XI.M27)

Drawings

663071-23, “Firewater and Transfer Tank 24” Roof Manhole and 12” Roof Vent,” Revision 4

663071-197, “Firewater and Transfer Tank 24” Shell Manhole,” Revision 3

663071-198, “Firewater and Transfer Tank 24” Shell Manhole,” Revision 4

663071-254, “Firewater and Transfer Tank Top Angle Details,” Revision 2

688803-47, “Firewater Transfer Tank Pipe Vault Slab,” Sheet 47, Revision 1

License Renewal

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Fire Water Operating Experience White Paper, Revision 9

Miscellaneous

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Procedures

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STP M-80B, “Indoor Fire Hose Operability Test,” Revision 17

STP M-80D, “Fire Hose Hydrostatic Testing,” Revision 1

Work Orders

C0215236	R0214212

B2.1.14 Fuel Oil Chemistry (XI.M30)

Action Requests

A0434425	A0669239	A0681636

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D6217–98, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration”

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.14, “Fuel Oil Chemistry,” Revision 3

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Miscellaneous

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Notification 50341844

Technical Specification Bases 3.8.3.3, Revisions 0 and 6

Technical Specification 5.5.13

Trending Results for Diesel Generator Fuel Oil Chemistry

<u>Procedures</u>

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STP M-10A, “Diesel Fuel Oil Storage Tank Inventory,” Revision 18

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STP M-10B, “Diesel Fuel Oil Testing Program,” Revision 19

STP M-10B1, “Emergency Diesel Fuel Oil Tank Analysis,” Revision 10

STP M-10B2, “Diesel Generator Day Tanks Fuel Oil Analysis,” Revision 5

STP M-10B3, “New Fuel Oil Shipment Analysis,” Revision 9

B2.1.23 Lubricating Oil Analysis (XI.M39)

<u>License Renewal</u>

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Procedures

MA1.DC51, "Preventive Maintenance Program," Revision 11

MA1.DC52, "Predictive Maintenance Program," Revision 6

TS1.ID15, "Lubricating Oil Analysis Program," Revision 0

Notifications

50036292	50041215

B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E3)

Action Requests

A0346247	A0476872	A0477350	A0477593	A0568168	A0571777
A0573248	A0623104				

Drawings

57563, "Cable Tray and Conduit Layout Plan below Elevation 119'-0" Area A," Revision 35

57568, "Cable Tray and Conduit Layout Plan below Elev. 107'-0" Area A," Revision 59

57597, "Embedded Conduit Layout El 85'-0" Areas FW-GW," Revision 12

57658, "Conduit Layout Outdoors Area 1," Revision 12

57660, "Conduit Layout Outdoors Area 3," Revision 21

57682, "General Arrangement of Electrical Pull Boxes and Duct Runs," Revision 22

57683, "General Arrangement of Electrical Pull Boxes and Duct Runs," Revision 16

438113, "Civil Electrical Pull Box Details BPO 40, 41 & 42 thru 45," Revision 5

438168, "Electrical Pull Box Details," Revision 4

500606, "Conduit Layout Outdoors Area 1," Revision 10

500608, "Conduit Layout Outdoors Area 3," Revision 7

500609, “Conduit Layout Outdoors Area 4,” Revision 4

500614, “Electrical Pull Boxes & Duct Runs,” Revision 16

500616, “Development of Pull Boxes,” Revision 6

500635, “Cable Tray and Conduit Layout Plan below Elev. 119’-0” Area A,” Revision 22

500669, “Electrical Cable Tray and Conduit Layout Plan Below El. 85’-0” Area H,” Revision 32

500674, “Embedded Conduit Layout Elevation 85’-0” Areas H & K,” Revision 5

500691, “Conduit and Lighting Layout Intake Structure Plan at EL. (+) 17.5’,” Revision 18

500692, “Conduit and Lighting Layout Intake Structure – Plan at EL + 5-0’,” Revision 12

500693, “Conduit and Lighting Schedule Intake Structure – Section A-A,” Revision 11

500694, “Conduit and Lighting Schedule Intake Structure – Section B-B,” Revision 15

500696, “Electrical Grounding Layout Intake Structure,” Revision 8

500816, “Conduit and Lighting Layout Intake Structure – Plan at EL (+) 17.5’,” Revision 24

500817, “Electrical Conduit and Lighting Layout Intake Structure – Plan Elev. +5’ – 0”,” Revision 17

500818, “Conduit and Lighting Layout Intake Structure Section A-A,” Revision 16

500819, “Conduit and Lighting Layout Intake Structure Section B-B,” Revision 19

500820, “Electrical Pull Boxes & Duct Runs,” Revision 10

500822, “Conduit and Lighting Layout Intake Structure – Details,” Revision 13

500823, “Grounding Layout Intake Structure,” Revision 7

501458, “Conduit Lights Layout-Lighting Intake Structure Plan Below EL. (-) 2.1’,” Revision 37

522196, “Civil Electrical Pull Box Layout Plan,” Revision 6

License Renewal

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Notifications

50200934	50270859	50313350

Procedures

AD7.DC8, “Work Control,” Revision 28

AWP E-016, “Inspection Guide – Maintenance Rule & License Renewal Structural Monitoring Programs – Civil,” Revision 4

TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0J

Work Orders

60000437	64020314	64057910	C0131754

B2.1.27 ASME Section XI, Subsection IWE

Action Requests

A0531657	A0532256	A0607396	A0695068

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License Renewal

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Miscellaneous

Configuration of Electrical Penetrations Drawing

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Notifications

50201281	50210309	50273826	50275027

Procedures

AD5.ID2, “Inservice Inspection Program,” Revision 8

ISI ADD SUCCESS, “Additional and Successive Inspections,” Revision 5

ISI VT GEN-1, “General Visual Examination of the Containment Liner,” Revision 1

NDE VT 3-L, “Visual Examination of the Containment Liner,” Revision 1

Work Orders

C0172212 C0172243

B2.1.28 ASME Section XI, Subsection IWL (XI.S2)

Drawings

103512, “Unit 1 & 2 Containment Structure Typical Rebar Strain Gage,” Revision 1

500001, “Area Location Plan,” Revision 11

663075-654-1, “Liner and Surface Embedded Strain Gage Installation,” dated January 2, 1971

663075-657-1, “Structural Rebar Strain Gauge Installation,” dated March 4, 1971

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.28, “ASME Section XI, Subsection IWL,” Revision 2

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Miscellaneous

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Notification 50341635

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Procedures

AD5.ID2, “Inservice Inspection Program,” Revision 8

ISI ADD SUCCESS, “Additional and Successive Inspections,” Revision 5

NDE VT 3C-1, “VT-3C Visual Examination of the Containment Concrete Shell,” Revision 1

B2.1.29 ASME Section XI, Subsection IWF

Action Requests

A0429454	A0430828	A0575046	A0609877	A0609880

Inspections

B7.70 – Class 1 bolts

SI-1669-8III WIC-55 weld

SI-119-8III WIC-45C & -45E welds

C6.10 related to CCP 1-1 weld

55S-2R – CCW surge tank braces

Hanger 75-1V

Hanger 75-4V

Hanger 75-5R

Hanger 5-25R

Hanger 5-23R

Hanger 5-24R

License Renewal

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Miscellaneous

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Procedures

AD5.ID2, "Inservice Inspection Program," Revision 8

ISI ADD SUCCESS, "Additional and Successive Inspections," Revision 5

ISI DATA, "Dispositioning of Recorded NDE Examination Data," Revision 4

ISI SCHED, "ISI Program Interval Three Examinations," Revision 3

MA1.ID13, "ASME Section XI Repair/Replacement Program and Implementation," Revision 13

NDE VT 3-1, "Visual Examination of Component and Piping Supports," Revision 1

B2.1.30 10 CFR Part 50, Appendix J (XI.S4)

Action Requests

A0492725	A0530700	A0556053	A0574159	A0574579	A0574763
A0603732	A0624602	A0650418	A0683314	A0718996	A0720865

License Renewal

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Notifications

50241125 50341877

Procedures

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STP M-7, “Integrated Leakage Rate Test (ILRT) Type A,” Revision 24

STP M-7E, “Containment Penetration Valve Lineup for the Integrated Leak Rate Test (ILRT),” Revision 5

B2.1.31 Masonry Wall (XI.S5)

Drawings

515213, “Unit 1 - Safety Related Masonry Walls, Turbine Building, Elevation 85’-0”, 107‘-0”, 119’-0”, 140’-0”,” Revision 6

515214, “Unit 2 - Safety Related Masonry Walls, Turbine Building, Elevation 85’-0”, 107’-0”, 119’-0”, 140’-0”,” Revision 6

515215, “Unit 1 & 2 - Safety Related Masonry Walls, Turbine Building, Elevation 85’-0”, 100’-0”, 115’-0”, 140’-0”154’-0”,” Revision 7

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.31, “Masonry Wall Program,” Revision 2

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Miscellaneous

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Procedures

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MA1.ID17, “Maintenance Rule Monitoring Program,” Revision 21

MA1.NE1, “Maintenance Rule Monitoring Program - Civil Implementation,” Revision 3

B2.1.32 Structures Monitoring (XI.S6)

Drawings

57718, “Equipment Location Plan at Elevation 85’-0” Turbine Building,” Revision 37

57719, “Equipment Location Plan at Elevation 104’-0” Turbine Building,” Revision 14

57720, “Equipment Location at Elevation 119’-0” Turbine Building,” Revision 17

57721, “Equipment Location at Elevation 140’-0” Turbine Building,” Revision 21

57722, “Auxiliary and Containment Buildings Plan at Elevations 60’-0” and 64’-0”,” Revision 15

57723, “Auxiliary and Containment Buildings Plan at Elevation 73’-0”,” Revision 16

57724, “Auxiliary and Containment Buildings Plan at Elevation 85’-0”,” Revision 28

57725, “Auxiliary, Containment, and Fuel Handling Buildings Plan at Elevations 91’-0” and 100’-0”,” Revision 29

57726, “Auxiliary, Containment, and Fuel Handling Buildings Plan at Elevation 115’-0”,” Revision 26

57727, “Auxiliary, Containment, and Fuel Handling Buildings Plan at Elevation 140’-0”,” Revision 32

57729, “Auxiliary and Containment Buildings Section B-B,” Revision 15

57730, “Auxiliary and Fuel Handling Buildings Section C-C,” Revision 13

57731, “Containment, Turbine, and Fuel Handling Buildings Section D-D,” Revision 11

438457, “Concrete Reinforcing – Plan at El. 115’-0” - Auxiliary Building Areas J, GE, and GW,” Revision 9

438458, “Concrete Reinforcing – Plan at El. 115’-0” - Auxiliary Building Areas H and K,” Revision 7

500001, “Area Location Plan,” Revision 11

500002, “Area A – Plans at Elevations 85’-0” & 107’-0”,” Revision 15

500003, “Area A – Miscellaneous Sections & Details,” Revision 14

500936, “Piping and Mechanical Areas J & L Plan at El. 115’-0”,” Revision 9

500938, “Piping and Mechanical Areas J & L Sections J and 4,” Revision 10

500964, “Equipment Location Plan at Elevation 85’-0” - Turbine Building,” Revision 31

500965, “Equipment Location Plan at Elevation 104’-0” - Turbine Building,” Revision 13

500966, “Equipment Location Plan at Elevation 119’-0” - Turbine Building,” Revision 14

500967, “Equipment Location Plan at Elevation 140’-0” - Turbine Building,” Revision 16

500968, “Equipment Location Plan at Elevations 60’-4”, 63’-6” & and 73’-0” - Containment Building,” Change 50

500969, “Equipment Location Plan Section A-A - Containment Building,” Revision 10

500971, “Containment & Fuel Handling Buildings Plan at Elevations 85’-0”, 91’-0”, and 100’-0”,” Revision 30

500977, “Containment Building Plan at Elevations 115’ and 140’,” Revision 20

Drawings - Tanks

438034, “Design Class I Tanks Concrete Foundations (Sheet 1 of 2),” Revision 7

438038, “Requirements for Water Storage Tanks,” Revision 8

443008, “Requirements for Water Storage Tanks,” Revision 4

443014, “Location Nozzle Schedule and Vault Details for Water Storage Tanks,” Revision 11

463987, “Exterior Concrete Tank Protection Concrete Foundations (Sheet 1),” Revision 25

508916, “Unit 1 - Outdoor Storage Tanks Piping Modification – Plan & Sections,” Revision 6

508918, “Unit 2 - Outdoor Storage Tanks Piping Modification – Plan & Sections,” Revision 4

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.32, “Structures Monitoring Program,” Revision 3

XI.S6 Structures Monitoring Program Operating Experience White Paper, Revision 0

Miscellaneous

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MA1.NE1, “Maintenance Rule Monitoring Program - Civil Implementation,” Revision 3

STP M-7W, “Containment Structural Integrity Inspection,” Revision 4

B2.1.33 Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)

Drawings

59459, “Concrete Outline Plan at Top Deck Area Intake Structure,” Revision 41

59460, “Concrete Outline Plan at Top Deck Area Intake Structure,” Revision 35

59461, “Concrete Outline Plan at Pump Deck Area Intake Structure,” Revision 39

59462, “Concrete Outline Plan at Pump Deck Area 2 Intake Structure,” Revision 35

59463, “Concrete Outline Plan at Invert Area 1 Intake Structure,” Revision 11

59464, “Concrete Outline Plan at Invert Area 2 Intake Structure,” Revision 12

Final Safety Analysis Report - Figures

3.8-75, “Intake Structure Transverse Section A”

3.8-76, “Intake Structure Transverse Section B”

3.8-77, “Intake Structure Transverse Section C”

3.8-78, “Intake Structure Wave Scale Model Plan-Invert Unit 1 NTS”

3.8-79, “Intake Structure Wave Scale Model Transverse Section D”

3.8-80, “Pipeway Structure Layout”

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.33, “Regulatory Guide 1.127, ‘Inspection of Water-Control Structures Associated with Nuclear Power Plants’,” Revision 3

XI.S6 Structures Monitoring Program Operating Experience White Paper, Revision 0

Procedures

AWP E-016, “Inspection Guidelines For the Maintenance Rule Monitoring Program - Civil Implementation,” Revision 4

MA1.ID17, “Maintenance Rule Monitoring Program,” Revision 21

MA1.NE1, “Maintenance Rule Monitoring Program - Civil Implementation,” Revision 3

PEP C-17.14, “Concrete Surveillance Program for the Saltwater Systems,” Revision 2

B2.1.36 Metal-Enclosed Bus (XI.E4)

Action Request

A0431246	A0431402	A0432093	A0433203	A0452196	A0452867
A0494268	A0516816	A0531296	A0554164	A0555908	A0574023
A0574949	A0574969	A0575531	A0604165	A0607134	

Drawings

57483, “General Arrangement Outdoors 230 kV and 500 kV Switchyards,” Revision 5

437530, “Single Line Meter & Relay Diagram 12 kV Start-up System,” Revision 36

437531, “Single Line Meter & Relay Diagram 12 kV System,” Revision 16

437532, “Single Line Meter & Relay Diagram 4160 V System,” Revision 27

437533, “Single Line Meter & Relay Diagram 4160 V System,” Revision 36

441227, “Single Line Meter & Relay Diagram 12 kV System Bus Sections D & E,” Revision 21

441228, “Single Line Meter & Relay Diagram 4160 V System Bus Sections D & E,” Revision 16

441229, “Single Line Meter & Relay Diagram 4160 V System Bus Section F,” Revision 16

441230, “Single Line Meter & Relay Diagram 4160 V System Bus Sections G & H,” Revision 23

500804, “Arrangement Standby Start-Up Transformers,” Revision 19

500805, “Arrangement Standby Start-Up Transformers,” Revision 14

502110, “Single Line Diagram 500/230/25/12/4.16kV Systems,” Revision 15

663339, “Electrical Installation Details for Indoor and Outdoor Bus Duct,” Sheet 15, Revision 6

663362, “Electrical Installation Details for Indoor and Outdoor Bus Duct,” Sheet 7, Revision 4

System Health Reports (2010)

3rd Quarter 4 kV Bus – Units 1 and 2

3rd Quarter 12 kV Bus – Units 1 and 2

3rd Quarter 230 kV Bus – Units 1 and 2

3rd Quarter 500 kV Bus – Units 1 and 2

3rd Quarter Main Generator – Units 1 and 2

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-B2.1.36, “Aging Management Program for Metal Enclosed Bus,” Revision 3

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Miscellaneous

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Notification 50333175

SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations,” dated September 1996

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Procedures

MP E-61.9A, “Isolated Phase Bus and Motor Operated Disconnect Maintenance,” Revision 17

MP E-63.3C, “Maintenance of 4 and 12 kV Switchgear,” Revision 22

MP E-63.3D, “4 & 12 kV Switchgear Bus Connection Resistance Test,” Revision 2

MP E-101A, “Infrared Thermography Inspections,” Revision 6

TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0J

B2.1.38 Transmission Conductor, Connections, Insulators and Switchyard Bus and Connections

Action Requests

A0413241	A0413242	A0568625	A0689901	A0694826	A0660739

Drawings

57486, “Arrangement of 500 kV Switch, Bus, & Circuit Breakers Structure,” Revision 11

57487, “Arrangement of 500 kV Switch, Bus, & Circuit Breaker Structures,” Revision 13

57483, “General Arrangement Outdoors 230 kV and 500 kV Switchyards,” Revision 5

435897, “Arrangement of 230 kV Switch, Bus, & Circuit Breaker Structures, Sections E-E, X-X, Y-Y, Paddle Switch Cabinets,” Revision 3

License Renewal

Aging Management Program Evaluation Report DCPP-AMP-PSSwyd, “Transmission Conductor, Connections, Insulators and Switchyard Bus and Connections,” Revision 1

Operating Experience White Paper 500 & 230 kV Transmission Lines and Switchyards, dated April 6, 2010

Miscellaneous

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NRC Supplemental Safety Evaluation of PG&E Response to Station Blackout Rule (10 CFR 50.63) for Diablo Canyon (TAC NOS. M68537 and M68538), dated May 29, 1992

Topical Report TR-11DC, “Electrical Component Aging Evaluations - License Renewal Topical Report,” Revision 0

Work Order 64039005

Notifications

50035101 50041476 50341482 50341749

Procedures

AD7.ID6, “Nuclear Generation/Supplemental Personnel Interface,” Revision 7

OP J-2:V, “Backfeeding the Unit From the 500kV System,” Revisions 13 and 14

TS1.DC1, “License Renewal Electrical Aging Management,” Revision 0J

Substation Maintenance and Construction Manual Instructions

“General Information,” Revision 7

“Master Table of Contents Substation Inspections,” Revision 7

“Substation Inspections,” Revision 7

“Arrestors, Bushings, and Insulators,” Revision 7

“Infrared Inspections,” Revision 7

System Reviews

Auxiliary Feedwater (03B), Diesel Generator (21) and Compressed Air (25)

Drawings – Auxiliary Feedwater

049058, “Component Material Identification,” Sheet 3, Revision 2

102003, “Feedwater System,” Sheet 4, Revision 75

106703, “Feedwater System OVID,” Sheet 3, Revision 71

DC663056, “Finned Cooling Coil,” Sheet 78, Revision 1

DC663314, “Cross Section Drawing 8” Double R/L Valve,” Sheet 113, Revision 7

LR-DCPP-03-106703-02, “License Renewal Boundary Drawing,” Revision 2

LR-DCPP-03-106703-03, “License Renewal Boundary Drawing,” Revision 2

LR-DCPP-03-106703-04, “License Renewal Boundary Drawing,” Revision 1

Drawings – Compressed Air

Selected license renewal boundary drawings for this system

Drawings – Diesel Generator

LR-DCPP-21-106721-02, “Diesel Fuel Oil System,” Revision 0

LR-DCPP-21-106721-03, “Starting Air and Dryer System for Diesel Engine 1-1,” Revision 0

LR-DCPP-21-106721-04, “Turbo Charger Air Assist and Dryer System for Diesel Engine 1-1,” Revision 0

LR-DCPP-21-106721-05, “Engine Fuel Oil System Diesel Engine 1-1,” Revision 0

LR-DCPP-21-106721-06, “Jacket Water Cooling System Diesel Engine 1-1,” Revision 0

LR-DCPP-21-106721-07, “Combustion Air and Exhaust System for Diesel Engine 1-1,” Revision 0

LR-DCPP-21-106721-08, “Starting Air and Dryer System for Diesel Engine 1-2,” Revision 0

LR-DCPP-21-106721-09, “Turbo Charger Air Assist and Dryer System for Diesel Engine 1-2,” Revision 0

LR-DCPP-21-106721-10, “Engine Fuel Oil System Diesel Engine 1-2,” Revision 0

LR-DCPP-21-106721-11, “Jacket Water Cooling System Diesel Engine 1-2,” Revision 0

LR-DCPP-21-106721-12, “Combustion Air and Exhaust System for Diesel Engine 1-2,” Revision 0

License Renewal System and Structure Scoping Report (DCPP-SCO-)

03B, “Auxiliary Feedwater,” Revision 3

21, “Diesel Generator System,” Revision 5

License Renewal Component Summary Screening Report (DCPP-SCR-)

03B, “Auxiliary Feedwater,” Revision 6

21, “Diesel Generator System,” Revision 4

25, “Compressed Air System,” Revision 3

License Renewal Aging Evaluation Report (DCPP-AER-)

03B, “Auxiliary Feedwater,” Revision 4

21, “Diesel Generator System,” Revision 5

25, “Compressed Air System,” Revision 3

Miscellaneous

Center of Business Corrective Action Program CCAP 2010-0143, “NRC Inspection Identified Corrections to Request for Additional Information Responses and License Renewal Application”

Compressor Tubing Photographs

License Renewal Application Table 3.3.2-14, “Auxiliary Systems – Summary of Aging Management Evaluation – Diesel Generator System”

Project Change Tracking Form PCTF-DC174

Procedure MP M-21.2, “Diesel Engine Generator Air Compressor (Quincy Model QR-25) Maintenance,” Revision 13

Notifications

50336850	50341879	50341911