UNITED STATES
**NUCLEAR REGULATORY COMMISSION**
REGION IV
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December 17, 2010

Mr. Mark E. Reddemann
Chief, Executive Officer
Energy Northwest
P.O. Box 968 (Mail Drop 1023)
Richland, WA 99352-0968

SUBJECT: COLUMBIA GENERATING STATION - NRC LICENSE RENEWAL INSPECTION REPORT 05000397/2010007

Dear Mr. Reddemann:

On November 4, 2010, a U.S. Nuclear Regulatory Commission (NRC) team completed the onsite portion of an inspection of your application for license renewal of your Columbia Generating Station. The team discussed the inspection results with Mr. S. Gambir, Vice President Technical Services, and other members of your staff during the exit meeting on November 4, 2010.

This inspection examined activities that supported the application for a renewed license for the Columbia Generating Station. 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 scoping and to observe any effects of equipment aging. The visual examination of structures, systems, and components also included some areas not normally accessible. 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 revising your license renewal application and revising aging management processes, which are described in the report.

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
Engineering Branch 2
Division of Reactor Safety

Docket: 50-397
License: NPF-21

Enclosure:
NRC Inspection Report 05000397/2010007
w/Attachment: Supplemental Information

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**U.S. NUCLEAR REGULATORY COMMISSION**
**REGION IV**

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| Dockets: | 05000397 |
| Licenses: | NPF-21 |
| Report: | 05000397/2010007 |
| Applicant: | Energy Northwest |
| Facility: | Columbia Generating Station |
| Location: | Richland, WA |
| Dates: | October 18 through November 4, 2010 |
| Inspectors: | G. Pick, Senior Reactor Inspector and Team Leader<br>C. Denissen, Reactor Inspector<br>J. Melfi, Reactor Engineer<br>G. Meyer, Senior Reactor Inspector<br>N. Okonkwo, Reactor Inspector<br>M. Williams, Reactor Inspector |
| Approved By: | Neil O'Keefe, Chief<br>Engineering Branch 2<br>Division of Reactor Safety |

**TABLE OF CONTENTS**

## SUMMARY OF FINDINGS

IR 05000397/2010007; 10/18/2010 – 11/04/2010; Columbia Generating Station, 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 that the applicant adequately performed scoping of nonsafety-related structures, systems, and components as required by 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, aging management programs, and processes.

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. NRC-Identified and Self-Revealing Findings

No findings of significance were identified

### B. Licensee-Identified Violations

No findings of significance were identified.

## REPORT DETAILS

## 4. OTHER ACTIVITIES

4OA5 Other - License Renewal

a. Inspection Scope (IP 71002)

NRC inspectors performed this inspection to evaluate the thoroughness and accuracy of the applicant's scoping of nonsafety-related structures, systems, and components (SSCs), as required by 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 with the potential to affect the safety functions of a structure, system, or component within the scope of license renewal. The term scoping related to the activities performed by the applicant to identify the population of SSCs that should be considered for aging management activities.

The team selected a sample of 34 of the 55 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. The team walked down accessible portions of the in-scope systems to observe aging effects and to review the material condition of the SSCs. The term in-scope refers to structures, SSCs that the applicant concluded would require aging management because they were passive or long-lived.

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

For scoping, the team reviewed the applicant's program guidance and scoping results. The team assessed the thoroughness and accuracy of the methods used to identify the SSCs required to be within the scope of the license renewal application, as required by 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.

The team reviewed the complete set of license renewal drawings, including drawing revisions. 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:

- Reactor building
- Turbine building
- High pressure core spray (HPCS) diesel generator room
- General services building
- Intake structure
- Corridors between radwaste, turbine, and diesel buildings
- Standby service water pump house
- Diesel fuel oil polisher building
- Fire protection pump houses
- 115 kV, 230 kV and 500 kV switchyards

For SSCs selected because of potential spatial interactions, where failure of nonsafety-related components could adversely affect adjacent safety-related components, the team determined that the applicant accurately categorized the in-plant configuration within the license renewal documents. The team determined the personnel involved in the process were knowledgeable and appropriately trained.

For SSCs selected because of potential structural interaction (seismic design of safety-related components potentially affected by nonsafety-related components), the team determined that the applicant accurately identified and categorized the structural boundaries within the program documents. Based on in-plant walkdowns and 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 components within the license renewal scope. The applicant had assembled an extensive basis to demonstrate the structural boundaries.

Subsequent to the application submittal, the applicant had added portions of additional systems to those already within the scope of license renewal based on lessons learned from another applicant. Specifically, the applicant walked down cables and piping located in building interfaces, such as the corridors between the turbine, radwaste, and diesel buildings. The team reviewed the walkdown inspection results and changes to the application based on the inspections and identified no concerns.

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

b.2 <u>Evaluation of New Aging Management Programs</u>

The team reviewed 14 of 20 new aging management programs to determine whether the applicant had established appropriate actions or had actions planned to manage the effects of aging. 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.

Because the applicant had not completed many of the elements identified in the new programs, including drafting implementing procedures, the team could not assess the effectiveness of the planned implementation of these programs. Some of the new programs were One-Time Inspection Programs that will involve testing of applicable components prior to the period of extended operation to confirm the absence of significant aging effects. If the results determine aging effects have occurred, the applicant will need to establish actions to manage the identified effects of aging.

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

.1 B.2.1 Aboveground Steel Tanks Inspection Program (XI.M29)

This program is a new One-Time Inspection Program that will be implemented in conjunction with the external surfaces monitoring program. The applicant planned to perform a volumetric inspection of the bottom surfaces of the carbon steel condensate storage tanks during the 10-year period prior to the period of extended operation. The volumetric inspection should provide direct evidence of any loss of material that has occurred or that could result in a loss of function.

The applicant identified an exception to the NUREG-1801, “Generic Aging Lessons Learned (GALL) Report – Tabulation of Results,” Volume 2, Revision 1 (GALL Report) because the tank had no sealant or caulking at the interface edge between the condensate storage tank and the concrete foundation. The team verified that the applicant had recently performed maintenance to remove the corrosion, install a bead of caulk, and repaint this interface. These actions restored the tank so that the tank configuration became consistent with the GALL Report. However, these actions did not determine whether any trapped moisture had corroded the tank bottom. The applicant had never volumetrically measured the bottom of the condensate storage tanks; however, the applicant documented their commitment to ultrasonically inspect the tank bottom in 2015 in Action Request 218619. The team considered this an appropriate corrective action to determine whether the tank bottom had corroded.

The team questioned the applicant how the program would be developed, including staff qualifications and applicable codes. The applicant had not developed details for the planned conduct of the inspections. The applicant currently relies on a monthly visual surveillance to detect any significant aging effects (e.g., corrosion) on the exterior of the tanks. The applicant had initiated Action Request 227787 to address the lack of knowledge of personnel who performed inspections of external surfaces. The applicant acknowledged that training will be necessary for the newly assigned program owners.

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, with implementation of the commitments noted above regarding training and ultrasonic examinations, the applicant provided a method to appropriately identify and address aging effects during the period of extended operation.

.2 One-Time Inspection Programs (XI.M32)

Introduction

As specified in GALL Report, Section XI.M32, One-Time Inspections include measures to verify the effectiveness of an existing aging management program and confirm the insignificance of an aging effect. Typical programs include the water chemistry, fuel oil chemistry, and lubricating oil analysis programs, and confirmation occurs through nondestructive evaluation of a sample of components maintained by these programs. Qualified personnel 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 during the 10 years prior to the period of extended operation.

The team noted that the applicant had split the one-time approach into 11 different aging management programs, including B.2.12 Chemistry Program Effectiveness Inspection (to address the Water Chemistry and Fuel Oil Chemistry Programs) and B.2.37 Lubrication Oil Inspection (to address the Lubricating Oil Analysis Program). However, the team questioned the suitability of a one-time approach for many of the other proposed programs. The team noted that the areas covered often had no existing aging management program or periodic activities. Prior to the inspection, the team contacted Division of License Renewal personnel, who indicated that they shared similar concerns related to the applicant's use of One-Time Inspection Programs for those that did not have existing programs.

In response, the applicant retained the aging management programs listed below as One-Time Inspection Programs since these programs were consistent with the GALL Report approach of confirming that existing aging management programs properly managed the effects of aging. The team had selected each of these aging management programs for review and will discuss them in this section.

- B.2.12 Chemistry Program Effectiveness Inspection
- B.2.16 Diesel Starting Air Inspection
- B.2.30 Heat Exchangers Inspection
- B.2.37 Lubricating Oil Inspection
- B.2.51 Supplemental Piping/Tank Inspection

In addition, the applicant stated that the aging management programs listed below would be converted into plant-specific aging management programs with periodic activities. The applicant planned to identify these programs as plant-specific during the annual amendment update in January 2011. The team selected the Cooling Units Inspection

Program and Diesel-Driven Fire Pumps Inspection Program for review, which will be discussed in later sections.

- B.2.14 Cooling Units Inspection
- B.2.17 Diesel Systems Inspection
- B.2.18 Diesel-Driven Fire Pumps Inspection
- B.2.27 Flexible Connection Inspection
- B.2.41 Monitoring and Collection Systems Inspection
- B.2.48 Service Air System Inspection

The applicant tracked the revisions to these aging management programs in accordance with Action Request 229026. In addition, the applicant tracked the revisions to the above One-Time Inspection Programs to plant specific, periodic inspection programs as part of their response to Request for Additional Information B.2.14-1 [**ML103010080**].

<u>Individual One-Time Inspection Program Reviews</u>

The team reviewed the draft NRC aging management program audit results, aging management program evaluation reports, responses to NRC requests for additional information, and plant specific operating experience. The team evaluated the basis used to identify the inspection samples and evaluated the scope of the proposed programs. The team discussed the program evaluations and planned activities with the responsible staff.

<u>B.2.12 Chemistry Program Effectiveness Inspection</u>

The applicant established this aging management program to detect and characterize the material conditions in representative low-flow and stagnant areas of plant systems influenced by the Boiling Water Reactor (BWR) Water Chemistry Program, the Fuel Oil Chemistry Program, and the Closed Cooling Water Chemistry Program. The planned visual and volumetric inspections should provide direct evidence of the presence and extent of a loss of material resulting from all types of corrosion in treated liquid environments that has occurred. The inspection also provides direct evidence of any cracking as a result of stress corrosion cracking.

The team questioned the basis for the sampling plan, which specified a 5 percent sample of applicable components up to 10 samples for each population of components grouped by material, environment, and component type. The applicant had not identified the number and size of the sample populations. The team pointed out that the NRC had improved guidance for determining the appropriate sample size, which would be included in Revision 2 of the GALL Report. The new guidance specified selecting a 20 percent sample up to 25 samples for each population of components grouped by material and environment. The applicant agreed and stated that the sampling plan would be revised to adopt the sampling plan of the GALL Report, Revision 2, once issued, and stated that the application would be revised to reflect this approach. This revision for sampling plan also applied to other One-Time Inspection Programs that had intended to use a 5 percent sample.

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 a revised sample plan, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

B.2.16 Diesel Starting Air Inspection

This program was credited with detecting and characterizing the material condition of the air dryers and downstream piping and components in the diesel starting air system. This program was intended to verify that the Air Quality Sampling program effectively controlled the moisture content in the diesel generator starting air system. The applicant planned to manage the effects of aging by performing visual and volumetric examinations on a sample population of air dryers and downstream piping components to identify evidence of any loss of material. The applicant planned to implement this program during the 10-year period prior to entering the period of extended operation.

The team confirmed that appropriately qualified personnel will perform the nondestructive evaluations by using procedures and processes consistent with the regulatory requirements. As noted under the discussion of B.2.12, Chemistry Program Effectiveness Inspection, the applicant stated that the sampling plan would be revised to that specified in Revision 2 to the GALL Report, Section XI.M32.

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 a revised sample plan, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

B.2.30 Heat Exchangers Inspection

This program was credited with evaluating the surface conditions of heat exchangers and coolers that were exposed to indoor air or to water with the chemistry controlled by the BWR Water Chemistry program or the Closed Cooling Water Chemistry program. The inspection will provide direct evidence as to what extent, if any, a reduction of heat transfer has resulted from fouling. This program included the following systems: diesel generator jacket water, diesel generator lubricating oil, fuel pool cooling, reactor recirculation seal coolers, radwaste building mixed air coolers, and the reactor core isolation cooling lube oil cooler. The applicant planned to implement this program during the 10-year period prior to entering the period of extended operation.

The applicant will select a representative sample and establish acceptance criteria based upon engineering evaluations that will consider the materials of construction, service conditions, expected aging effects, and operating experience (e.g., time in-service, most susceptible locations, lowest design margins). Any inspection results that do not meet the acceptance criteria will be evaluated using the corrective action process to determine the need for subsequent aging management activities and for monitoring and trending of the results.

The team determined the applicant planned to use appropriately qualified examination personnel and techniques routinely used to evaluate the heat exchangers in other plant programs. As noted under the discussion of B.2.12, Chemistry Program Effectiveness Inspection, the applicant stated that the sampling plan would be revised to that specified in Revision 2 to the GALL Report, Section XI.M32.

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 a revised sample plan, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

B.2.37 Lubricating Oil Inspection

This program was credited with identifying loss of material resulting from corrosion or selective leaching, or reduction in heat transfer resulting from fouling on surfaces exposed to lubricating oil. This program will verify that the Lubricating Oil Analysis program has been effective in managing aging. The program included the control rod drive; control room chilled water; diesel jacket water, starting air, exhaust, generators and lubricating oil systems; fire protection; low pressure core spray; reactor core isolation cooling; and standby service water systems. The applicant planned to implement these inspections during the 10-year period prior to the period of extended operation.

A representative sample of components, with special emphasis on locations that may be susceptible to the collection of entrained water, will be examined for evidence of loss of material or reduction in heat transfer. The applicant planned to conduct an engineering evaluation to develop the sample plan. The oil-wetted surfaces of aluminum, aluminum alloy, copper alloy, copper alloy with more than 15 percent zinc, steel, gray cast iron, and stainless steel components for in-scope systems constitute the sample population. As noted under the discussion of B.2.12, Chemistry Program Effectiveness Inspection, the applicant stated that the sampling plan would be revised to that specified in Revision 2 to the GALL Report, Section XI.M32.

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 a revised sample plan, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

B.2.51 Supplemental Piping/Tank Inspection

This program was credited with evaluating the material condition of steel, gray cast iron, and stainless steel components exposed to moist air environments, particularly the wet/dry environments that exist at air-water interfaces or in the air spaces of in-scope tanks. The inspection will use nondestructive evaluation to identify any loss of material resulting from corrosion. The applicant planned to implement this program during the 10-year period prior to entering the period of extended operation.

The team determined that, although the inspection program had not been developed, the applicant demonstrated that personnel were familiar with performing nondestructive examinations and visual inspections for the types of components and piping likely to be affected. The applicant planned to select a representative sample of components, with special emphasis on locations that may be susceptible to loss of material resulting from corrosion. The applicant planned to conduct an engineering evaluation to develop the sample plan. As noted under the discussion of B.2.12, Chemistry Program Effectiveness Inspection, the applicant stated that the sampling plan would be revised to that specified in Revision 2 to the GALL Report, Section XI.M32.

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 a revised sample plan, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.3 B.2.14 Cooling Units Inspection Program (Plant Specific)

The team identified that the applicant had incorrectly identified this aging management program as a One-Time Inspection Program; however, this program did not confirm the insignificance or absence of aging effects based on existing aging management programs and periodic activities. Following discussions with the team, the applicant stated that this program would be changed to a plant-specific program with periodic activities and that the application would be revised to reflect these changes. As such, the team reviewed this program prior to the expected revisions.

This program was a new, plant-specific aging management program credited with identifying evidence of cracking, loss of material, or reduction in heat transfer at susceptible locations because of similarities in materials and environmental conditions. The inspection program will evaluate the material condition of aluminum, steel, copper alloy, and stainless steel cooling unit components that are exposed to condensation in order to ensure the pressure boundary integrity and heat transfer capability of the units. The program will have periodic aging management activities that will evaluate the internal surfaces of the cooling units, particularly drain pans, cooling fins, and drain piping.

The team reviewed the draft NRC aging management program audit results, aging management program evaluation report, responses to NRC requests for additional information, and plant operating experience. The applicant specified that the program would use qualified personnel to conduct nondestructive examinations, including visual, ultrasonic, and surface techniques. The team discussed the program evaluations and planned activities with the responsible staff.

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 applicant was expected to provide subsequent guidance to appropriately identify and address aging effects during the period of extended operation because of the change to a plant specific, periodic program. The team could not evaluate the revised approach since program had not been developed at the time of the inspection.

.4 B.2.18 Diesel-Driven Fire Pumps Inspection Program (Plant Specific)

The team identified that the applicant had incorrectly identified this aging management program as a One-Time Inspection Program; however, this program did not confirm the insignificance or absence of aging effects based on existing aging management programs and periodic activities. Following discussions with the team, the applicant stated that this program would be changed to a plant-specific program with periodic activities and that the application would be revised to reflect these changes. As such, the team reviewed this program prior to the expected revisions.

This program was a new, plant-specific program credited with identifying loss of material due to corrosion or erosion, reduced heat transfer due to fouling, or stress corrosion cracking of susceptible materials. The program was credited with detecting and characterizing the material condition of the interior of diesel-driven fire pumps' steel exhaust lines that were exposed to an outdoor air environment and copper alloy, copper alloy with more than 15 percent zinc, gray cast iron, and stainless steel heat exchanger components exposed to a raw water environment. The program will be revised to include periodic aging management activities that will evaluate the internal surfaces of the exhaust lines and the heat exchanger components. The applicant planned to implement this program during the 10-year period prior to entering the period of extended operation.

The team reviewed the license renewal documents, the NRC aging management program audit results, and the aging management program evaluation report. The applicant specified that the program would use qualified personnel to conduct nondestructive examinations. The team discussed the program evaluations and planned activities with the responsible staff.

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 applicant was expected to provide subsequent guidance to appropriately identify and address aging effects during the period of extended operation because of the change to a plant specific, periodic program. The team could not evaluate the revised approach since program had not been developed at the time of the inspection.

.5 B.2.19 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E1)

This was a new aging management program, consistent with the GALL Report, credited with managing aging effects on cables and connections (terminal blocks, fuse holders, and electrical penetration assemblies) resulting from adverse localized environments. The applicant defined adverse localized environments as a limited plant area that had conditions significantly more severe than the specified design or bounding plant environment for the general area. These conditions included heat, radiation, and moisture in the presence of oxygen. The aging effects being reviewed included surface anomalies, such as embrittlement, cracking, discoloration, crazing, crumbling, melting, and any other distinct visual evidence of oxidation, material deterioration, or other visible degradation. The applicant identified the plant areas for evaluation of adverse localized environments in the aging management program evaluation report for this program. The applicant planned to perform a baseline inspection prior to the period of extended operation and once every 10 years thereafter.

The team reviewed license renewal documents, the aging management program evaluation report, corrective action program documents, and plant operating experience. In addition, the team searched the corrective action program database for relevant action requests. The team walked down selected plant areas and looked for adverse localized environments. The team interviewed design engineers and project personnel to determine their plans for conducting these aging effects evaluations.

The applicant planned to develop their program using the guidance in Electric Power Research Institute Report TR-109619, "Guideline for Management of Adverse Localized Environments." The applicant indicated that they would visually inspect a representative sample of accessible electrical cables and connections located in adverse localized environments to identify any effects of aging. The applicant planned to establish the technical basis for the sample size and inspection locations, which would include consideration of the insulation material, area temperatures, radiation levels, and moisture levels. The inspections of accessible cables and connections would also review for visual anomalies on cable jackets, which could be a leading indicator of insulation degradation.

The team concluded that the applicant performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in cables exposed to adverse localized environments. The team concluded that, if implemented as described, including establishing an appropriate sample plan, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.6 <u>B.2.21 Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Inspection Program (XI.E6)</u>

This was a new, One-Time Inspection Program, consistent with the GALL Report, credited with managing the effects of aging for the metallic parts of in-scope non-environmentally qualified electrical cable connections. The applicant planned to inspect for loosening of bolted connections that could result from stressors such as thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation of the metallic parts. The applicant planned to evaluate a representative sample of electrical connections for in-scope components based upon the service application, circuit loading, and environment. The applicant planned to document the technical basis for the sample size and the acceptance criteria used for each inspection/test.

The team reviewed license renewal documents and the aging management program evaluation report. The team searched the corrective action program database for relevant action requests. Because this was a new One-Time Inspection Program, the applicant had not developed any program for performing these inspections. During interviews, the team determined that the applicant planned to implement the process described in Report CGS-RPT-LRAMR-E01, “Aging Management Review of Electrical Component Commodity Groups,” Revision 1. The applicant stated that they would evaluate a representative sample of the various electrical cable connections exposed to differing environments (heat, power level, moisture, and so forth) throughout the facility.

The applicant took an exception to the GALL Report requirement to perform the test at least once every 10 years; instead, the applicant specified they would perform a one-time verification inspection of these cable connections. The applicant based their exception on the fact that connections found to be loose during maintenance were repaired and that they routinely conduct thermography inspections throughout the plant. The team identified no concerns with this exception based on the review of plant operating experience. In addition, the team noted that a one-time inspection was consistent with the recommendations in 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.’”

The team concluded that the applicant 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, including establishing an appropriate sample plan, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.7 <u>B.2.32 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E3)</u>

This is a new aging management program, consistent with the GALL Report, credited with managing aging related to normally energized inaccessible medium voltage cables that could be exposed to significant moisture. The applicant planned to manage the aging effects by periodically inspecting for water collection in cable manholes and conduits and draining water as needed. The applicant planned to conduct testing of their in-scope inaccessible medium-voltage electrical cables prior to the period of extended operations and once every 10 years thereafter. In addition, the applicant planned to visually inspect associated manholes and hand holes to identify any collection of water with the first programmatically required inspection to occur during the 2 years prior to entering the period of extended operation and continuing at least every 2 years thereafter.

The team reviewed license renewal documents, the aging management program evaluation report, the draft implementing procedure, corrective action documents, plant operating experience, and work orders. The team searched the corrective action program database for relevant action requests. The team interviewed plant personnel and walked down several underground cable manholes.

The applicant inspected the cable manholes for the presence of water based on plant experience with water accumulation during preventive maintenance activities. The team confirmed that the applicant planned to perform periodic inspection at least once every year (including event-driven inspections) and testing every 6 years. Whenever plant personnel found water in manholes, they measured and sampled the water prior to pumping the water from the manhole. If the applicant identified anomalies during the testing, they would take actions in accordance with the corrective action program.

The applicant had experienced issues of degraded cable insulation for low voltage power, instrumentation, and control cables due to localized overheating. The applicant had experienced no failures of medium-voltage cables because of water treeing; however, two cables damaged during installation had failed following later moisture intrusion. The applicant continued to address water intrusion in two manholes adjacent to the cooling towers with standing water. At the time of the inspection, the applicant had identified this deficiency in Action Requests 204169 and 204201 but had yet to identify the source of the water. The team did not identify any submerged cables during the plant walkdowns or any water in the manholes that had been identified as susceptible to water intrusion.

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.

.8 B.2.40 Metal-Enclosed Bus Program (XI.E4)

This was a new program, consistent with the GALL Report, credited with managing the aging affects associated with degradation of nonsegregated metal-enclosed bus ducts, including bolted bus bar connections, insulators, supports, and elastomers. The parameters monitored include loose connections, embrittlement, cracking, melting, swelling or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, water intrusion, and cracking of internal bus supports. The applicant will utilize thermography to check a sample of the bolted connections and visually inspected the internal bus enclosure, bus insulation, and internal bus supports. The program included the 6.9 kV and 4 kV non-segregated buses associated with Start-Up Transformer E-TR-S that supported the plant response to a station blackout, as components that required monitoring. Both the thermography and the visual inspections will be performed at least once every 10 years, with the first inspections to be completed during the 10-year period prior to the period of extended operation.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, preventive maintenance tasks, and plant operating experience. The team walked down the in-scope non-segregated bus ducts and interviewed the license renewal project personnel and the responsible engineers.

The applicant took an exception to the GALL Report because the applicant planned to inspect the bus joints, seals, and gaskets during disassembly of the bus duct covers when conducting internal inspections of the bus duct. The applicant took this exception because these inspections, normally performed by structural inspectors on a 5-year frequency, will be performed by electricians during the 10-year inspections of the metal-enclosed buses. The team identified no concerns with this exception.

The team determined that the applicant inspected, cleaned, and performed thermography on the metal-enclosed bus ducts during outages in accordance with existing preventive maintenance tasks. The team reviewed onsite operating experience that reinforced the need for these inspections since the applicant had previously had a catastrophic failure of a 6.9 kV nonsegregated bus in 2009. The applicant attributed the failure to relaxation of bolted connections on the center phase flexible link due to repeated thermal cycling. The loosened bolts allowed for heating of the joint, which further degraded the connections and eventually resulted in the formation of a high energy arc fault between phase conductors. The applicant improved the preventive maintenance task to incorporate the lessons learned from the root cause evaluation of the failure, including installing windows in the bus duct covers to allow for more direct thermography of the connections.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent plant and industry experience to determine the effects of aging on the metal enclosed non-segregated 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.

.9 B.2.47 Selective Leaching Inspection Program (XI.M33)

This 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 and hardness testing of a sample of components with metallurgical properties susceptible to selective leaching to determine whether loss of material had occurred. Further, the program evaluates whether selective leaching, if it had occurred, would affect the ability of the components to perform the intended function during the period of extended operation. The applicant indicated that they intended to perform these one-time evaluations during the 5-year period prior to entering the period of extended operation.

The team reviewed the license renewal application, the draft NRC aging management program audit results, aging management program evaluation report, and plant operating experience. The team discussed the program evaluations and planned activities with the responsible staff.

The team noted that the applicant had not included aluminum bronze (i.e., copper alloy containing greater than 8 percent aluminum) as requiring an aging effects evaluation by this program. The applicant responded that material specifications from construction did not provide sufficient information to properly categorize aluminum bronze. However, as an alternative, the applicant had categorized any susceptible material as another bronze (i.e., copper alloy containing greater than 15 percent zinc). The team considered this an appropriate method to address the problem and include the components within the program.

The team noted that different parts of the license renewal application specified different timing for conducting the evaluations required by this program. Specifically, Section B.2.47 stated program “activities will be conducted no earlier than 5 years prior to the end of the current operating license,” while Section A.1.2.47 stated “inspection activities will be conducted during the 10-year period prior to the period of extended operation.” The applicant stated that they intended to perform inspections within 5 years prior to the period of extended operation, which would meet both specifications.

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 and systems that have metal alloys subject to this mechanism. 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 B.2.49 Small Bore Class 1 Piping Inspection Program (XI.M35)

This was a new, One-Time Inspection Program, consistent with the GALL Report, credited with managing the effects of cracking of small bore Class 1 piping (less than 4 inches diameter) that were exposed to reactor coolant. The applicant planned to manage the effects of aging by performing volumetric examinations on selected butt and socket weld locations of high safety significance. The applicant specified they would use the guidance described in Electric Power Research Institute Report 1000701, “Interim Thermal Fatigue Management Guideline (MRP-24),” dated January 2001, with considerations for physical accessibility, exposure levels, nondestructive examination techniques, and locations identified in NRC Information Notice 97-46, “Unisolable Crack in High-Pressure Injection Piping,” dated July 9, 1997. The applicant planned to complete these inspections during the 10-year period prior to entering the period of extended operation. The components affected included orifices, fittings, piping, valve bodies, and any other pressure retaining parts.

The team reviewed license renewal program basis documents, aging management review documents, and industry documents related to thermal fatigue on small bore piping. In addition, the team searched the corrective action database for relevant action requests. The team interviewed the program owner. The team could not review any inspection procedures for review of the small-bore socket welds since the applicant had not developed an inspection procedure.

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 small-bore Class 1 piping. The team concluded that, if implemented as describe, the applicant would provide guidance to appropriately identify and address aging effects during the period of extended operation.

b.3 Evaluation of Existing Aging Management Programs

The team sampled 18 of the 31 existing aging management programs, which included three plant specific aging management programs, 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., new 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 B.2.2 Air Quality Sampling Program (Plant Specific)

This plant-specific, existing program was credited with managing loss of material due to corrosion in the diesel generator starting air system and ensuring the control air system remained dry and free of contaminants. The program periodically monitored the air quality through sampling for hydrocarbons, dew point, and particulates in both systems, and periodically performed ultrasonic inspections of diesel starting air system air receivers. The applicant based this program on their commitments to Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," dated August 8, 1988.

The team reviewed the implementing procedures, inspection results, projected end of life charts for equipment, surveillance test trend data, numerous corrective action program documents that described plant experience, and work orders. The team searched the corrective action database for relevant action requests using keywords. In addition the team interviewed the cognizant engineers and walked down the systems. During the diesel starting air system walkdown the team observed a shiftly blowdown of the air receivers.

The team identified plant operating experience that had an effect on the condition of diesel generator starting air system air receivers, which resulted from a design issue. Since 2002, the diesel generator starting air systems for each of the diesel generators routinely failed to pass the dew point surveillance during the summer months, which required multiple blowdowns of the air receivers until the dew point was acceptable. In 2006, the applicant had approved a design change to replace the existing desiccant-type air dryers with refrigerant air dryers. However, the applicant cancelled the modification without resolving the problem. The team confirmed that, in 2010, the applicant identified that replacing the desiccant prior to the start of summer in the existing air dryers would correct the condition and allow the air receivers to pass the dew point surveillance.

The team expressed concern with this solution since the team noted multiple examples where replacing the desiccant did not result in meeting the required dew point without multiple blowdowns. This continued condition allowed for alternating wet/dry conditions that corroded the air receivers. The applicant documented this concern in Action Request 228631 and indicated that they planned to revisit whether replacing the desiccant was the appropriate corrective action to resolve this deficiency. The team noted the air receivers continued to have sufficient wall thickness to prevent affecting the tank integrity from a review of the surveillance test data and ultrasonic test results.

The team concluded that the applicant had performed appropriate evaluations, with exceptions noted above, 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 addressing the noted deficiency, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred.

.2 <u>B.2.3 Appendix J Program (XI.S4)</u>

This was an existing program, consistent with the GALL Report, credited with managing aging effects related to a loss of leak tightness in the primary containment. This program detects degradations of the primary containment by monitoring leakage rates across the primary containment shell and associated welds, air locks, hatches and containment penetrations (mechanical, electrical, and instrument & control), and blind and testable flanges. The leakage limits were specified in licensing basis documentation and the Technical Specifications.

The team reviewed the license renewal documents, the aging management program evaluation report, the NRC aging management program audit results, corrective action documents, and plant operating experience. The team interviewed the cognizant engineer and found the individual to be knowledgeable. The team reviewed the most recent integrated leak rate test results as well as the trend from previous tests. Since the applicant implemented a performance-based leak rate test program, the applicant performed integrated leak rate tests on a 10-year frequency and performed Type B and Type C at the frequencies allowed by their program and regulatory requirements. The program owner demonstrated detailed knowledge of the test requirements.

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, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.3 B.2.4 Bolting Integrity Program (XI.M18)

This was an existing program, consistent with the GALL Report, credited with managing the aging effects related to cracking, loss of material, and loss of preload for pressure retaining bolting and American Society of Mechanical Engineers (ASME) component support bolting. This program included the periodic inspection of bolting for aging effects by using the Inservice Inspection Program, the Inservice Inspection Program – IWF, the Structures Monitoring Program, and the External Surfaces Monitoring Program.

The team reviewed license renewal program documents, the aging management program evaluation report, plant operating experience, implementing procedures, and corrective action documents. The team walked down the reactor core isolation cooling and high pressure core spray systems to evaluate the effectiveness of the existing program. The team confirmed that plant personnel had corrected and evaluated the impact of bolting deficiencies related to mechanical equipment and structural joints from a review of completed work activities and corrective action documents.

The applicant took three exceptions to the GALL Report that included: (1) using guidelines other than that referenced in the GALL Report, (2) establishing other aging management programs as the actual inspection programs, and (3) planning to ensure that bolting acceptance criteria exists or would be created prior to the period of extended operation in the other aging management programs. The applicant relied on guidance contained in manufacturer information, vendor information, and the recommendations contained in Electric Power Research Institute NP-5067, "Good Bolting Practices," for proper material selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections instead of the guideline referenced in the GALL Report. The team identified no concerns with this exception.

The applicant credited the Inservice Inspection Program and the Inservice Inspection Program – IWF for periodic inspection of ASME-Class 1, 2, 3, and MC bolting. The applicant looked for bolting degradation or leakage during implementation of the External Surfaces Monitoring Program or Structures Monitoring Program instead of using this program for these purposes. The team determined the applicant documented leaks through bolted connections in their corrective action program and established an appropriate method to evaluate and manage leaks. The applicant based their leak management program on guidance from Electric Power Research Institute TR-114761, "Establishing an Effective Fluid Leak Management Program," dated December 2000. The team identified no concerns with this exception.

The applicant did not include any specific acceptance criteria in this program. However, the applicant established acceptance criteria or will establish acceptance criteria regarding bolting in other aging management programs. Specifically, the applicant planned to establish the criteria for periodic inspection of bolting for aging effects in the Inservice Inspection Program, the Inservice Inspection Program – IWF, the Structures Monitoring Program, and the External Surfaces Monitoring Program. The team identified no concerns with this exception.

The applicant selected bolting materials, lubricants and sealants in accordance with industry guidance. In addition, the applicant established torque values and restricted use of molybdenum disulfide as a lubricant in accordance with industry guidelines and manufacturer recommendations. Maintenance practices and bolting replacement activities included proper gasket activation, preload, torquing, and fit-up of bolting in accordance with manufacturer, vendor, or industry recommendations.

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 pressure retaining bolting and component support bolting. 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 B.2.5 Buried Piping and Tanks Inspection Program (XI.M34)

The Buried Piping and Tanks Inspection program was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material due to corrosion. 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 circulating water; diesel fuel oil; fire protection; radwaste building heating, ventilation, and air conditioning; standby service water; tower makeup water; and condensate systems.

The team reviewed the aging management program evaluation report, implementing procedures and corrective action documents. The team reviewed plant specific operating experience, a cathodic protection system evaluation report, and the Buried Pipe Integrity program. The team interviewed engineers responsible for the buried pipe program and the cathodic protection systems.

This program required two enhancements to be consistent with the GALL Report. The first enhancement required adding the radwaste building outside air system to this program. The team considered this enhancement appropriate since this was an in-scope system with buried piping. The second enhancement related to establishing the excavation requirements for this program. Specifically, the applicant specified that they would excavate a section of buried pipe section within 10 years prior to entering the period of extended operation and within 10 years after entering the period of extended operation. The team confirmed this enhancement met the requirements in the GALL Report.

The team determined that the applicant had upgraded the cathodic protection system to replace the existing post anode system with deep well anode beds. From a review of plant operating experience and interviews, the team determined the applicant replaced the existing system to improve reliability. During interviews, the applicant informed the team that they planned to upgrade the remaining portion of the existing system that provided protection of the standby service water piping with a deep well anode bed. The team confirmed that the existing system continued to operate properly and provided appropriate protection for the standby service water system. The applicant tracked completion of the modifications under Action Request 13802, Action 8.

The applicant stated that they planned to revise their buried pipe aging management program to adopt the guidance in Section XI.M41 Buried and Limited-Access Piping and Tanks program described the draft Revision 2 to the Gall Report. The applicant indicated they would use the option that included maintaining cathodic protection of the in-scope buried piping. This planned program change included other types of underground piping (e.g., polymeric, cementitious, and concrete), piping in underground vaults, control of backfill materials, maintenance and monitoring of the cathodic protection system, and more extensive inspections as listed in the applicant's table in the draft aging management program evaluation report.

The applicant had developed a buried pipe program that followed the recommendations contained in Electric Power Research Institute Report 1016456, "Recommendations for an Effective Program to Control the Degradation of Buried Pipe." The team determined that the applicant had not completed their risk ranking of the piping included as part of these recommendations; however, the team determined that the applicant had initiated actions to begin risk ranking the systems.

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 with enhancement and design changes, the applicant developed guidance to appropriately identify and address aging effects during the period of extended operation.

.5 <u>B.2.8 Boiling Water Reactor (BWR) Stress Corrosion Cracking Program (XI.M7)</u>

This was an existing program, consistent with the GALL Report, credited with managing stress corrosion cracking and intergranular attack of austenitic stainless steel and nickel alloy piping, nozzle safe ends, nozzle thermal sleeves, valves, flow elements, and pump casings. The applicant based this program on their responses to generic letters, industry documents, and the inservice inspection program. The applicant utilized preventive measures to mitigate aging effects and used inspection and flaw evaluation to monitor for the effects of stress corrosion cracking and intergranular attack. The program applied to the above types of components and piping greater than 4 inches diameter that has reactor coolant that exceeds 200ºF.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, plant operating experience, program health reports, and corrective action program documents. The team interviewed the program owner and cognizant engineers. The team determined that the applicant monitored the affected component welds for flaws as part of their 10-year inservice inspection plan. The applicant implemented hydrogen water chemistry and noble metal chemical application to mitigate the effects of intergranular stress corrosion cracking.

The team confirmed that the applicant had performed additional preventive measures on welds susceptible to stress corrosion cracking and intergranular attack. Specifically, prior to the initial plant startup and during the first refueling outage the applicant performed an Induction Heating Stress Improvement process on 148 susceptible piping welds. In addition, the applicant performed a Mechanical Stress Improvement Process on multiple reactor pressure vessel nozzle-to-safe end and safe end-to-pipe welds during the 1994 refueling outage.

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, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.6 B.2.11 BWR Water Chemistry Program (XI.M2)

This was an existing program, consistent with the GALL Report, credited with mitigating damage related to loss of material due to corrosion or erosion, stress corrosion cracking, and reduction of heat transfer for susceptible components that contain treated water. This program maintained the chemical environment in systems that contain treated water, including reactor coolant, reactor feedwater or condensate, demineralized water, sodium pentaborate solution, and steam. The applicant planned to supplement this program with inspections conducted as part of the one-time Chemistry Program Effectiveness Inspection Program.

The team reviewed self assessments, program procedures, chemistry trend data, corrective action documents, and plant operating experience. The team interviewed the cognizant engineer and discussed relevant action requests, including recent challenges with condenser in-leakage and slightly high copper levels in the feedwater. The applicant planned to replace the condenser in order to address the corrosion of the condenser tubes. The team verified that the applicant administered the water chemistry programs in accordance with the Technical Specifications and guidance contained in Electrical Power Research Institute Report TR-103515, “BWR Water Chemistry Guidelines.” The team noted that the applicant had implemented hydrogen water chemistry and noble metal chemical addition to minimize the potential for stress corrosion cracking.

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, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.7 B.2.13 Closed Cooling Water Chemistry Program (XI.M21)

This was an existing program, consistent with the GALL Report after enhancement, credited with mitigating damage due to loss of material, cracking, and reduction in heat transfer for components in closed-cycle cooling water systems. The program included monitoring and control of corrosion inhibitor and chemistry parameters consistent with the guidance of Electric Power Research Institute TR-107396, “Closed Cooling Water Chemistry Guideline,” Revision 1. Also, this program included periodic corrosion rate measurements at select locations in the reactor closed cooling water system. The applicant maintained water chemistry by adding a nitrite-based corrosion inhibitor and pH chemicals. The systems included within the scope of this program were diesel generator cooling water, reactor closed cooling water, and radwaste building chilled water. The applicant planned to supplement this program with inspections conducted as part of the one-time Chemistry Program Effectiveness Inspection and one-time Heat Exchanger Inspection programs.

The team reviewed the implementing procedures, corrosion rate data, and chemistry data for the monitored systems. The team walked down a sample of heat exchangers and pumps cooled by closed cooling water systems and interviewed the system engineer. The team determined from the data and trend graphs reviewed that the applicant successfully monitored heat transfer and loss of material in the in-scope systems. The team verified that the applicant appropriately identified heat exchangers that had a structural integrity function and heat exchangers whose failure could spatially affect safety-related components.

The applicant planned to enhance this program by performing additional measurements of reactor closed cooling water system corrosion rates prior to entering the period of extended operation. The applicant would initiate additional measurements and their frequency depending upon the corrosion rate results.

The applicant took exception to the GALL Report recommendations to conduct performance or functional testing for heat exchangers and pumps. In lieu of performance monitoring/functional testing, the applicant planned to continue taking measurements of corrosion rates in the reactor closed cooling water system. Additionally the one-time Chemistry Program Effectiveness Inspection program will confirm that loss of material and cracking in low flow and stagnant areas is not significant, and the one-time Heat Exchangers Inspection program will confirm adequate heat transfer. The team did not identify any concerns with these exceptions.

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 with enhancement, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.8 B.2.23 External Surfaces Monitoring Program (XI.M36)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material for external surfaces of steel components, cracking of aluminum and stainless steel components, and hardening and loss of strength for elastomer-based mechanical sealants and flexible connections in ventilation and mechanical systems. The applicant uses visual inspections during engineering walkdowns each refueling cycle to evaluate system or component bolting, ducting, fans, and flexible connections in ventilation systems, and external surfaces of piping, tanks, expansion joints, and other mechanical components.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, long-range planning documents, and system engineer qualification procedures.

The applicant planned to enhance the program to add specific guidance to the implementing procedures for system engineer walkdowns and maintenance instructions related to ventilation systems. Specifically, the applicant planned to add the following to implementing procedures: (1) include aluminum, copper alloys, gray cast iron, and stainless steel to the scope of the program; (2) include cracking as an aging effect for aluminum and stainless steel; (3) include visual or volumetric examination techniques; (4) include elastomer-based mechanical sealants and flexible connections in ventilation systems; and (5) include physical examination techniques to monitor for hardening and loss of strength of elastomers. The team noted that the applicant previously identified that they had not provided guidance for evaluation of elastomers. The applicant initiated Action Request 227787 to identify that training was needed to enhance the knowledge level of personnel responsible for identifying aging effects, particularly corrosion, on the external surfaces of pipes. The applicant stated that they recognized the need to conduct training for personnel expected to identify aging effects on SSCs. The applicant had scheduled training related to identifying aging effects, as described in Action Request 225303.

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 with enhancement, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.9 B.2.25 Fire Protection Program (XI.M26)

This was an existing program, consistent with the GALL Report, credited with managing loss of material, cracking, delamination, separation, and change in material properties for susceptible in-scope components that performed a fire barrier function. The applicant planned to manage the effects of aging through visual inspections of fire barriers (walls/ceilings/floors), fire-rated penetration seals, fire wraps, fire proofing, and fire-rated doors. The applicant visually inspected 10 percent of each type of fire-rated penetration seal every 18 months; visually inspected the exposed external surfaces of fire barriers, fire wraps, and fire proofing for abnormal degradations/changes in appearance that could affect the barrier function every 18 months; conducted monthly tests of the fire pumps to verify proper flow; tested the sequential starting/controller functions for the diesel-driven fire pumps every 5 years; and visually inspected essential fire-rated doors and functionally tested the lockset, bolt mechanism, and closing mechanism every 6 months. The applicant inspected non-essential doors annually and non-essential fire barriers every 6 years.

The team reviewed the implementing procedures, program enhancements, health reports, completed surveillance tests, work orders, plant operating experience, and corrective action documents. The team interviewed fire protection personnel. The team walked down various fire barriers throughout the plant to observe the physical condition of the barriers and to assess the effectiveness of the existing program. The team also walked down the diesel-driven fire pump and accessible portions of the associated fuel supply line.

The applicant took two exceptions to the GALL Report. The applicant identified that no aging management would be required for existing carbon dioxide and halon systems. The carbon dioxide protected the turbine generator exciter housing, and the Halon 1301 protected the main control room. The team confirmed that neither the turbine generator exciter housing nor the control room area had any license renewal functions. The team identified no concerns related to this exception. Also, the applicant did not include evaluating the condition of the fuel oil supply lines within this program. Rather the applicant included condition monitoring of the diesel-driven fire pump fuel oil tanks in the Fuel Oil Chemistry Program and planned to evaluate the supply line in accordance with the Chemistry Program Effectiveness Inspection Program when confirming the effectiveness of the Fuel Oil Chemistry Program. The team identified no concerns related to this exception.

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, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.10 <u>B.2.26 Fire Water Program (XI.M27)</u>

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the loss of material resulting from corrosion, erosion, and macrofouling of susceptible materials in the fire protection system components exposed to raw water. This program applied to carbon steel, gray cast iron, copper alloy, copper alloy with more than 15 percent zinc, and stainless steel for piping and mechanical piping components. This program included fire water system piping and components such as pump casings, sprinkler heads, tubing, standpipes, orifices, strainer bodies, and hydrants.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, plant operating experience, corrective action documents, and surveillances. In addition, the team searched the corrective action program database for relevant action requests. The team interviewed plant personnel and walked down fire water system equipment, including the fire pumps and associated piping.

The applicant planned the following enhancements to the program prior to the period of extended operation. The applicant will either replace sprinkler heads that have been installed for 50 years or submit representative sprinkler head samples to a recognized laboratory for field service testing in accordance with National Fire Protection Association 25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.” The applicant will also perform either ultrasonic testing or internal visual inspection of portions of above-ground fire protection piping that are exposed to water but do not normally experience flow, prior to the end of the current operating term and at reasonable intervals thereafter, based upon the inspection results.

The applicant performed the following types of specific activities annually, as required by their licensee controlled specifications in accordance with applicable National Fire Protection Association codes: (1) flow testing of the fire water supply piping, including monitoring of system pressure; (2) hydrostatic testing, flushing to remove debris, and visually inspecting essential yard fire hydrants and associated hoses; and (3) visually inspecting spray and sprinkler headers for signs of degradation and blockage.

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 with enhancements, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.11 <u>B.2.28 Flow-Accelerated Corrosion Program (XI.M17)</u>

This was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material in steel and gray cast iron components that contain high energy fluids. The program implemented the Electric Power Research Institute guidelines in NSAC-202L, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” Revision 3. The applicant included components in this program that carry water or steam at design temperatures greater than 200°F. The applicant included the affected systems as a subset of their pipe wall thinning program. The applicant planned to enhance their existing program to add in-scope systems and materials.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, corrective action program documents, plant operating experience, and surveillance results. In addition, the team searched the corrective action program database for relevant action requests. The team interviewed the program owner and license renewal project personnel.

The team determined that the GALL Report endorsed Revision 2 of NSAC-202L. The team 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 team determined the procedures and methods used in the flow-accelerated corrosion program remained 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.”

The applicant planned to enhance the existing program to be consistent with the GALL Report by adding containment nitrogen system components supplied with steam from the auxiliary steam system and adding gray cast iron as a material identified as susceptible to flow-accelerated corrosion to the scope of the program. The team identified no concerns with this enhancement.

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 with enhancements, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.12 B.2.29 Fuel Oil Chemistry Program (XI.M30)

This was an existing program, consistent with the GALL Report, credited for managing the loss of material and cracking on the internal surface of diesel fuel oil storage tanks through monitoring and control of fuel oil quality. The applicant controlled contaminants in accordance with their Technical Specifications and American Society of Testing Materials (ASTM) standards related to fuel oil quality. The applicant periodically checked for water in fuel oil tanks, conducted 10-year preventive maintenance cleaning and visual inspection of the diesel generator fuel oil tanks, and tested new fuel oil before introducing it into the auxiliary boiler fuel tank. In addition, the applicant planned supplemental one-time inspections by the Chemistry Program Effectiveness Inspection.

The team reviewed the aging management program, implementing procedures, and relevant corrective action documents. The team interviewed plant personnel and conducted walkdowns of the diesel generators, diesel generator day tanks, diesel-driven fire pump, and the fuel oil polisher skid. From a review of plant operating experience, the team determined that no additional aging effects had occurred that would require modifying this aging management program. The team noted that the applicant utilizes the auxiliary boiler fuel oil tank as a holding tank prior to refilling the diesel generator fuel oil tanks.

The applicant described four exceptions to the GALL Report. The team verified the applicant remained capable of managing aging effects, as required by the GALL Report. The first and third exceptions related to the scope and parameters monitored for the diesel-driven fire pump fuel oil tanks. The first exception related to not testing new fuel prior to adding the fuel oil to these tanks. The third exception related to not testing these tanks for particulates during the quarterly tests. The team determined that the tanks had 3-micron filters and the diesel engine could operate with particulates as large as 12 microns. The team confirmed that the quarterly chemistry test results showed consistently acceptable fuel oil quality in these tanks. Also, the diesel-driven fire pumps had not failed to pass surveillance tests because of clogged fuel filters. In addition, the applicant described that, if fuel were to be introduced of poor quality or the fuel oil filters become clogged, the applicant would drain and clean the tanks then replace all the fuel in the affected diesel-driven fire pump fuel oil tank. The team identified no concerns with these exceptions.

The second exception related to the decision to not add biocides, stabilizers or corrosion inhibitors to the fuel oil for the diesel generators. The applicant stated that they provided an appropriate, alternate method for maintaining fuel oil quality without the addition of biocides, stabilizers or corrosion inhibitors based on their plant operating experience. Specifically, the applicant drained and cleaned the fuel oil tanks on a 10-year frequency and had the capability to use their fuel oil polishing skid to remove water and particulates from the fuel oil tanks. The team identified no concerns with this exception.

The fourth exception related to the method used to detect aging effects. The applicant elected to use side stream samples rather than the multi-level sampling specified in the GALL Report. The applicant informed the team that they had previously responded to Request for Additional Information B.2.29-2 on this topic. The team confirmed that ASTM D2276 allowed using ASTM D5452 for samples taken from a side stream that did not allow for using a field monitor (used a continuous flow stream). The team determined the applicant's method provided sufficient volume to purge the polisher line of any fuel from another storage tank than the one being sampled. This ensured that the applicant had a homogeneous sample from the portion of the tank likely to collect water and particulates. The team identified no concerns with this exception.

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 in those systems containing diesel fuel oil. 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.

.13 B.2.31 High-Voltage Porcelain Insulators Aging Management Program (Plant Specific)

This was an existing, plant-specific program credited with managing the build-up of hard water residue deposited by the vapor plume from the circulating water system cooling towers. The applicant identified the need to include this plant-specific program because reactor trips resulted from hard water deposits on the 500 kV bus pedestal insulators in the transformer yard. This program required coating insulators every 10 years to prevent the build-up of residues or cleaning on a 2-year frequency to remove residues from the high-voltage station post insulators between the 115 kV backup transformer (E-TR-B) and Circuit Breaker E-CB-TRB.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, and plant operating experience. The team searched the corrective action program database for relevant plant-specific operating experience. The team interviewed the license renewal project personnel and the cognizant engineers. The team conducted walkdowns of the transformer yards and the in-scope equipment.

The applicant excluded the 500 kV insulators because they did not fall within the scope of license renewal. Further, the applicant appropriately included the 115 kV station post insulators because they provided power required during a station blackout and would be subject to hard water deposits caused by spray drift from the cooling towers. The team determined that the applicant did not include the high-voltage station post insulators at the 230 kV ASHE A809 Breaker located in the Ashe Substation even though this breaker provided an alternate path of power during a station blackout. The applicant did not include these station post insulators because they concluded the spray drift phenomenon would not occur due to the significant distance from the circulating water system cooling towers.

During discussions with the team, the applicant provided a cooling tower drift study that identified that hard water deposits on the 500 kV breaker station post insulators had allowed arcing to occur. The study did not demonstrate that the 230 kV station post insulators would remain unaffected. Further, the applicant could not provide any other information to support their conclusions. Consequently, the applicant issued Action Requests 228661 and 228673 to resolve this concern. The applicant indicated that they would either establish appropriate coating or cleaning tasks or develop information that would demonstrate why the phenomenon would not affect the 230 kV switchyard station post insulators.

The team concluded that, with the exceptions noted above, the applicant had performed appropriate evaluations and considered pertinent plant operating experience to determine the effects of aging from the hard water deposits on the high-voltage porcelain insulators. The team concluded that with the possible exception noted, if implemented as described, the applicant developed guidance to appropriately identify and address aging effects during the period of extended operation.

.14 B.2.34 Inservice Inspection Program – IWE (XI.S1)

This 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 containment, its integral attachments, and containment pressure-retaining bolting. As specified by ASME Section XI, Subsection IWE, the applicant visually inspected accessible portions of the containment considered Class MC. The items subject to inspection included the liner plate and its integral attachments, moisture barriers, pressure-retaining bolting, and welds including base metal. The applicant evaluated the aging effects of pressure-retaining seals and gaskets in accordance with the Appendix J program.

The team reviewed license renewal documents, the aging management program evaluation report, industry operating experienced related to containment liners, corrective action documents, plant operating experience, and previous inspection results.

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, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.15 B.2.36 Lubricating Oil Analysis Program (XI.M39)

This was an existing program, consistent with the GALL Report after enhancement, credited with maintaining oil systems free of contaminants (primarily water and particulates), thereby preventing environmental conditions conducive to loss of material, cracking, or fouling. The applicant sampled, analyzed, and trended the results for numerous components in the program to provide an early indication of adverse equipment conditions The applicant sampled lubricating oil for most equipment at vendor-recommended frequencies. The applicant will enhance the program to include the diesel-driven fire pump diesel engine lube oil coolers, piping and pump casings since they were part of an in-scope component.

The team reviewed license renewal documents, the aging management program evaluation report, plant operating experience, self-assessments, implementing procedures, and relevant corrective action documents. The team interviewed plant personnel and toured the lubrication laboratory. Further, the team evaluated the condition of lubricating oil components during walkdowns of the train C emergency diesel generator, the diesel-driven fire pumps, and the reactor core isolation cooling system. The team reviewed oil measurement results and trending within the applicant's database.

The team identified a discrepancy between the aging management program expectations and the actual plant practice regarding testing lubricating oil for water content. Specifically, Section 2.3.b of the aging management program evaluation report stated, "Water content is determined on all samples by means of a Karl Fisher test." The team found that the applicant did not test diesel generator lubricating oil samples by the Karl Fisher test. The team determined that the applicant avoided performing the Karl Fisher test because the test had resulted in numerous false positives on diesel generator lubricating oil samples due to the presence of specific oil additives. The team confirmed that the applicant used an alternate test to measure water content in the diesel generator lubricating oil samples. The applicant issued Action Request 1314, Assignment 89, to clarify the description in the LRPD-05, "Aging Management Program Evaluation Results," Revision 5, by listing the actual test being used.

The team identified that the applicant had not effectively implemented actions in response to industry operating experience related to silver content in the diesel generator lubricating oil. Specifically, NRC Information Notice 2002-22, "Degraded Bearing Surfaces in GM/EMD Emergency Diesel Generators," dated June 22, 2002, and Report 10CFR21-83, "Pistons Used in EMD 645 Engines," dated July 31, 2002, addressed potential diesel engine bearing problems, which would result in indications of high silver content in lubricating oil samples. In response, the applicant instituted an action level of 0.8 ppm silver that required initiating work orders to evaluate the condition of the bearings. The team identified that recent oil samples on Diesel Generator 1 had exceeded this limit (up to 2.0 ppm) three times within 6 months without the applicant initiating any evaluations.

Action Request 228715 documented this deficiency and indicated that limitations in the initial test, which used an Induction Coupled Plasma method, may have resulted in false high positive values. The applicant believed the reading might be false since the October 2010 readings exceeded 1 ppm for all five diesel generators. The applicant initiated the additional test using the low silver test method as prescribed by Problem Evaluation Request 202-3374 in response to the above operating experience. Action Request 228715 documented that changing the confirmation test frequency from monthly to annually combined with inexperienced personnel removed two administrative barriers that might have identified the out-of-specification values earlier. The applicant had not identified actions to correct the lack of awareness for the out-of-specification measurement by the end of the inspection. The team concluded the applicant had not been effective in applying external operating experience even though they had properly processed and incorporated the information into this program.

The team concluded that, except for the above discrepancies, 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 with enhancement, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.16 B.2.38 Masonry Wall Inspection Program (XI.S5)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing cracking of masonry walls and degraded structural steel restraint systems of the masonry walls. The applicant identified that they intended to continue to use the guidance contained in the Maintenance Rule Structures Monitoring Program to perform the visual inspections. The team confirmed that the applicant had masonry walls in the circulating water pump house, turbine building, and the nonsafety-related portion of the radwaste control building. The applicant had no safety-related masonry block walls. The team determined that the applicant will conduct the masonry block wall civil inspections at the same frequency required by the Maintenance Rule program during the period of extended operation.

The team reviewed license renewal documents, the aging management program evaluation report, plant procedures, plant operating experience, corrective action documents, and prior inspection results. The team searched the corrective action database for relevant corrective action program documents. The team discussed the program with cognizant engineers and visually examined accessible masonry block walls to assess their condition.

This program required one enhancement to be consistent with the GALL Report. Specifically, the applicant planned to establish requirements to evaluate masonry cracking or degraded steel edge supports/bracing to ensure that the current evaluation basis remained valid. Further, the applicant would require corrective action if the extent of masonry cracking or steel degradation invalidated the evaluation basis. The applicant could opt to develop a new evaluation basis that accounted for the degraded condition of the masonry wall but continued to meet their design basis requirements.

The applicant planned to revise the program to require that inspection personnel meet 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 basic guidelines for conducting visual inspections of concrete in service. In addition, the applicant would conduct visual inspections of the external masonry wall surfaces prior to the loss of the structure’s intended functions. The team noted that the applicant had implemented both of these changes in response to requests for additional information.

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 with enhancements, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.17 B.2.42 Open-Cycle Cooling Water Program (XI.M20)

This was an existing program, consistent with the GALL Report after enhancement, 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 through inspection and surveillance tests combined with chemistry controls and cleaning to minimize fouling, loss of material, and cracking. The existing program implemented the recommendations of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989. The systems included the standby service water and plant service water systems, and components connected to or serviced by these systems. In addition, the applicant planned to include components serviced by the tower makeup and circulating water systems.

The team reviewed the aging management program evaluation report, implementing procedures, and relevant corrective action documents. The team reviewed self assessments, standby service water system chemistry data, heat exchanger test results, tube plug maps, and corrosion coupon trend data. In addition, the team interviewed the program manager and walked down accessible portions of the service water system, the ultimate heat sink spray ponds, and the service water pump house. The team determined from the data and trend graphs reviewed that the applicant monitored heat transfer and loss of material in the spray ponds and piping. The team reviewed plant operating experience and determined that room air coolers had become fouled in the mid-1990s. The applicant implemented a batch hydrogen peroxide treatment that removed biological growth in the spray ponds and cleared the fouling from the standby service water system.

The applicant identified several required enhancements to this aging management program to be consistent with the GALL Report. The applicant needed to add program elements to address cavitation erosion in standby service water, circulating water, plant service water, and tower make-up systems. Plant operating experience revealed that these systems had experienced multiple small leaks that resulted from cavitation erosion downstream of standby service water system valves. The team confirmed from a review of plant operating experience that the applicant needed to enhance this program to account for cavitation erosion. Another enhancement required adding nonsafety-related components within the scope of license renewal for the standby service water, circulating water, plant service water, and tower make-up systems. In addition, the applicant needed to add nonsafety-related components in the following systems serviced by the plant service water system: process sampling and process sampling radioactive systems, radwaste building mixed air and return air systems, reactor building return air system, and reactor closed cooling water systems.

The team reviewed the exceptions taken by the applicant to the GALL Report for this aging management program. The applicant established chemistry controls and heat transfer testing in response to Generic Letter 89-13. The applicant identified that the piping design had no lining and the chemistry controls and heat transfer testing provided an appropriate alternative to lined piping. The team identified no concerns with this exception. The applicant tested their in-scope heat exchangers every 24 weeks. This frequency resulted in more frequent tests than the annual test requirement in the GALL Report. The team identified no concerns with this exception.

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 with enhancements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.18 B.2.44 Preventive Maintenance – RCIC [*reactor core isolation cooling*] Turbine Casing Program (Plant Specific)

This was an existing, plant-specific program credited with managing the loss of material resulting from corrosion on the internal steel surfaces in the reactor core isolation cooling turbine casing, piping, and components in steam lines downstream from the steam admission valve (RCIC-V-45). The other components included the steam exhaust piping up to the suppression pool surface and the barometric condenser because of the similarities in materials and environment. The corrosion mechanism of concern resulted because the piping internals alternated between a relatively hot, dry steam environment during operation and a moist, internal air environment when the system was in standby. Qualified personnel performed these condition monitoring inspections on a 10-year frequency. The applicant had established this frequency based upon previous inspection results. The applicant inspected the casing and considered the identified condition reflective of the condition in the other components.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, and plant operating experience. The team reviewed the corrective action program database for relevant plant-specific operating experience. The team interviewed the license renewal project personnel and the cognizant engineers. The team conducted plant walkdowns of the reactor core isolation cooling system and the in-scope equipment.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent plant operating experience to determine the effects of aging from internal corrosion of the reactor core isolation cooling turbine casing. 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.

.19 B.2.50 Structures Monitoring Program (XI.S6)

This was an existing program, consistent with the GALL Report after enhancements, credited with managing cracking, loss of material, and change in material properties for concrete structures, steel, and structural supports. The applicant performed inspections as part of their Maintenance Rule structural inspection program for concrete elements, structural steel, masonry walls, structural features (e.g., caulking, sealants, roofs, etc.), structural supports, and miscellaneous components such as doors. This program included the Masonry Wall and Water Controlled Structures Programs (discussed separately). The aging management program evaluation report identified that the existing program would need to be enhanced to add numerous in-scope structures.

The team reviewed license renewal documents, the aging management program evaluation report, existing procedures, corrective action program documents, and plant operating experience. The team searched the corrective action database for relevant action requests. The team interviewed cognizant engineers who conducted the structural inspections and walked down the structures.

The team reviewed Action Request 179589 that described a surface crack that had existed on the exterior of the reactor building since the original plant construction in 1978. The applicant had concluded that no apparent structural impact or affect on operability of the secondary containment existed, since the secondary containment continued to meet the Technical Specifications' requirements for leakage. The crack had been filled with grout sometime in the past and sealed with caulk in 2008 to prevent potential moisture intrusion. The applicant determined that a concrete pour had been interrupted. The applicant believed that the crack resulted from a cold joint, and only affected the interior and exterior reactor building surfaces. The team was concerned that a possible aging mechanism existed in that the amount of time that the crack had been unsealed could have allowed moisture to affect the reinforcing steel.

Also, the team noted that, although the applicant had photographs for comparison, the applicant had not documented a detailed characterization of the crack size and had not been routinely monitoring the crack. The applicant initiated Action Request 228112 to evaluate the structural adequacy of the wall during a design basis earthquake and to evaluate the environmental impacts on the reinforcing steel to assess whether this was an aging issue. The team considered the applicant's actions to evaluate the flaw and determine any environmental effects to be appropriate. The team noted that this structural defect and the lack of detailed records of the flaw size and length and whether it had grown reinforced the need of the applicant to enhance their Structural Monitoring Program documentation related to structural defects.

The team identified that the applicant did not include clear and concise acceptance criteria and did not identify the detail required when documenting structural defects. Different inspectors conducting inspections did not have the ability to identify and trend changes in structural defects because of this lack of detail in records. The applicant acknowledged that their procedures did not include the necessary guidance to ensure that records would contain sufficient detail to identify and trend changes in defects. The applicant identified the need to enhance this program in Action Request 210816, Assignment 38. Commitment 12916 described the scope of the enhancements that included developing additional guidance for quantifying, monitoring, and trending inspection results; identifying specific criteria and action levels for initiating additional inspections; and referring to American Concrete Institute 349.3R-96 as a basis for developing acceptance criteria for structures and structural elements. In addition, the applicant recognized challenges related to knowledge management and knowledge transfer as their staff experience levels declined. The applicant had scheduled training related to identifying aging effects, as described in Action Request 225303.

The applicant identified the following required enhancements in order to be consistent with the GALL Report. Under scope, the applicant planned to add the listed in-scope structures and components. Under parameters monitored or inspected, the applicant: (1) required inspections of below-grade structures whenever they become accessible; (2) specified that the term "structural component" included any component that credited this program; and (3) specified sampling groundwater and raw water testing results every 4 years during different seasons for pH, sulfates, and chlorides to confirm that the environments remained non-aggressive. The team identified no concerns with these enhancements.

The team confirmed that the applicant planned to adopt several additional recommended program improvements that were not needed to ensure this program would be consistent with the GALL Report. The program improvements included such as incorporating the inspection guidance in construction standards, requiring minimum experience levels and qualifications, and identifying construction standards that provided details related to acceptance criteria. The team concluded these recommendations, if adopted, provided for a more comprehensive monitoring and evaluation 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 with enhancements, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.20 B.2.53 Water Control Structures Inspection Program (XI.S7)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the effects of aging and degradation of the structures and operational capability of Seismic Category I spray ponds and standby service water pump houses, and of Seismic Category 2 makeup water pump house and cooling tower basins. The applicant did not commit to Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," Revision 1; however, planned enhancements would incorporate aspects of Regulatory Guide 1.127. The applicant implemented this program as part of the Structures Monitoring Program conducted under the Maintenance Rule.

The team reviewed the license renewal documents, the aging management program evaluation report, the NRC aging management program audit results, corrective action program documents, assessments, and applicant responses to requests for additional information. The team interviewed the assigned program engineer and found the individual to be knowledgeable.

The applicant planned to enhance this program to be consistent with the GALL Report by: (1) listing the in-scope water control structures, (2) describing the Regulatory

Guide 1.127 inspection elements, as well as submerged inspection requirements, (3) ensuring the descriptions of concrete conditions conform with the appendix to the American Concrete Institute 201, “Guide for Making a Condition Survey of Concrete in Service,” and (4) documenting and trending defects, including using photographs to enhance trending.

The applicant planned to enhance the acceptance criteria section of this program by referencing American Concrete Institute 349.3R-96 to indicate this standard provided an acceptable basis for developing acceptance criteria for this program. The team determined that the applicant planned to establish quantitative degradation limits, similar to the three-tier acceptance criteria from American Concrete Institute 349.3R-96, Chapter 5 in the inspection procedure. The applicant would use the acceptance criteria to trigger different levels of inspection and to initiate corrective actions. The affected structural elements included concrete structural elements, steel liners, joints, coatings, and waterproofing membranes.

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 structures. The team concluded that, if implemented as described with enhancements, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

b.4 System Reviews

The team performed a vertical slice review of selected in-scope systems to assess 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:

- Compressed air and gas
- Diesel generator starting air
- Diesel generator lubricating oil
- High pressure core spray
- Reactor core isolation cooling
- Standby service water

The team interviewed the license renewal staff members and the system engineers responsible for the high pressure core spray, reactor core isolation cooling, diesel 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.

The compressed air and gas systems included four different systems: containment instrument air, control air, service air, and containment nitrogen. The four systems had differing environments. The aging effects requiring management for the containment instrument air, control air, and service air systems included loss of material and loss of preload. The applicant credited the External Surfaces Monitoring Program and the Bolting Integrity Program for all three programs. In addition, the applicant added the Service Air Inspection Program to the service air system to manage the identified aging effects. The aging effects requiring management for the containment nitrogen system included cracking, loss of material, and loss of preload. The applicant credited the following aging management programs to manage the identified aging effects: Bolting Integrity, BWR Water Chemistry, Chemistry Program Effectiveness Inspection, External Surfaces Monitoring, Flow-Accelerated Corrosion, and Selective Leaching Inspection. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

The aging effects requiring management for the diesel generator starting air system included loss of material and loss of preload. The applicant credited the following aging management programs for managing the identified aging effects: External Surfaces Monitoring, Air Quality Sampling, and One-Time Diesel Starting Air Inspection. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

The aging effects requiring management for the diesel generator lubricating oil system included loss of material, reduction in heat transfer, and loss of preload. The applicant credited the following aging management programs for managing the identified aging effects: Bolting Integrity, Lubricating Oil Analysis, External Surface Monitoring, Lubricating Oil Inspection, Closed Cooling Water Chemistry, Heat Exchangers Inspection, and Chemistry Program Effectiveness Inspection. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

For the high pressure core spray system, the aging effects requiring management included loss of material and loss of preload. The applicant credited the following aging management programs for managing the identified aging effects: Bolting Integrity, BWR Water Chemistry, Chemistry Program Effectiveness Inspection, External Surfaces Monitoring, Selective Leaching Inspection, and Supplemental Piping/Tank Inspection. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

For the reactor core isolation cooling 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: Bolting Integrity, BWR Water Chemistry, Chemistry Program Effectiveness Inspection, External Surfaces Monitoring, Flow-Accelerated Corrosion, Heat Exchangers Inspection, Lubricating Oil Analysis, Lubricating Oil Inspection, Preventive Maintenance - RCIC Turbine Casing, and Supplemental Piping/Tank

Inspection Programs. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

The aging effects requiring management for the service water system 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: Bolting Integrity, Buried Piping and Tanks Inspection, External Surface Monitoring, Lubricating Oil Analysis, Lubricating Oil Inspection, Open-Cycle Cooling Water, Selective Leaching Inspection, and Supplemental Piping/Tank Inspection. The team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

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.

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 the 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. S. Gambir, Vice President Technical Services, and other members of the applicant's staff during an exit meeting conducted on November 4, 2010. The applicant acknowledged the NRC inspection observations. The team returned all proprietary information reviewed during this inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

### KEY POINTS OF CONTACT

Applicant

S. Avery, Design Engineer Electrical
W. Boehnke, System Engineer
C. Blake, System Engineer Diesel Generators
S. Burn, System Engineer Diesel Generators
J. Cantrell, System Engineer Control and Starting Air
K. Christianson, Licensing Engineer
D. Coleman, Manager, Regulatory Programs
J. Cowin, Chemistry Specialist
J. Curren, License Renewal Cables Program
S. Dallas, Electrical System Engineer
J. Dorwin, Inservice Inspection Engineer
M. Eades, License Renewal Licensing Engineer
M. Ferebauer, Buried Piping Program
S. Gambir, Vice President Technical Services
D. Gregoire, Licensing Supervisor
T. Hancock, System Engineering Program Manager
W. Harper, Fire Protection Engineer
R. Herman, System Engineer Electrical
M. Holle, System Engineer
A. Langdon, License Renewal Room Lead
J. LaSalle, ASME Code Program Engineer
A. Mostala, Project Manager – License Renewal
D. Niver, System Engineer Electrical
R. Oakes, Flow Accelerated Corrosion Program Engineer
R. Olsen, System Engineer Fire Protection
J. Person, License Renewal Electrical Lead
D. Ramey, Inservice Inspection Engineer
B. Sawyer, License Renewal Room Lead
J. Scott, Vibrations and Oil Program Engineer
M. Shobe, Chemist
M. Shoup, Operations Support
J. Ting, System Engineer High Pressure Core Spray
J. Twomey, License Renewal Civil Lead
S. Wood, License Renewal Mechanical Lead
J. Worthington, License Renewal Mechanical Lead

AREVA

M. Carter, License Renewal Mechanical Lead – Balance of Plant
S. Chu, Civil Lead
R. Finnin, Class 1 Engineer
J. Hamlen, Electrical Lead
D. Lee, Project Engineer
M. Tafazzoli, License Renewal Project Manager

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**Scoping**

Drawings

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**New Programs**

**B.2.1 Aboveground Steel Tanks Inspection Program (XI.M29)**

Action Requests

| | | | |
|---|---|---|---|
| 227787 | 218647 | 218619 | 211176 |

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**B.2.12 Chemistry Program Effectiveness Inspection Program (XI.M32)**

Miscellaneous

Aging Management Program Evaluation Report for the Chemistry Program Effectiveness Inspection Program

Condition Report 2-05-6248

Letter GO2-10-135, “Response to Request for Additional Information,”
dated September 13, 2010

**B.2.16 Diesel Starting Air Inspection Program (XI.M32)**

<u>Miscellaneous</u>

Action Request Report 182962

Aging Management Program Evaluation Report for the Diesel Starting Air Inspection Program

Problem Evaluation Request 202-1537

Projected End of Life Chart for DSA-TK-1B

<u>Work Orders</u>

| | | |
|---|---|---|
| 01111048 | 01111047 | 01155517 |

**B.2.30 Heat Exchangers Inspection Program (XI.M32)**

<u>Miscellaneous</u>

Aging Management Program Evaluation Report for the Heat Exchangers Inspection Program

**B.2.37 Lubricating Oil Inspection Program (XI.M32)**

<u>Condition Reports</u>

| | | | | | |
|---|---|---|---|---|---|
| 25626 | 34518 | 45473 | 48837 | 54895 | 198470 |

<u>Miscellaneous</u>

Aging Management Program Evaluation Report for the Lubricating Oil Inspection Program

Plant Tracking Log Item H100534

**B.2.51 Supplemental Piping/Tanks Inspection Program (XI.M32)**

<u>Miscellaneous</u>

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**B.2.14 Cooling Units Inspection Program (Plant Specific)**

Drawings

LR-M548-1, "HVAC for Control and Switchgear Rooms, Radwaste Building," Revision 0

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Miscellaneous

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**B.2.18 Diesel-Driven Fire Pumps Inspection Program (Plant Specific)**

Miscellaneous

Aging Management Program Evaluation Report for the Diesel-Driven Fire Pumps Inspection Program

Condition Report 2-07-02170

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**B.2.19 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E1)**

Condition Reports

2-06-08714 2-07-02348 2-07-05600

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B.2.21 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification

Requirements Inspection Program (XI.E6)

Action Requests

| | |
|---|---|
| 176429 | 180870 |

Condition Reports

| | | | | | |
|---|---|---|---|---|---|
| 2-04-02910 | 2-05-08122 | 2-07-03708 | 2-07-03719 | 2-07-03721 | 2-07-03722 |

Miscellaneous

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**B.2.32 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E3)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| 179459 | 204053 | 204095 | 204201 | 204169 | 204344 |
| 204521 | 204696 | 208107 | 211443 | 225576 | |

Drawings

S525, Sheet 1, “Structural Transformer Area Foundations,” Revision 5

S526, Sheet 2, “Structural Transformer Area Foundations,” Revision 3

E823, Sheet 1, “Underground and Duct Banks Plan and Profiles,” Revision 25

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Work Orders

| | | |
|---|---|---|
| 29078962 | 01177814 | 01178182 |

**B.2.40 Metal-Enclosed Bus Program (XI.E4)**

Action Requests

| | | |
|---|---|---|
| 218590 | 227689 | 227872 |

Condition Reports

2-07-04710 2-07-04884

Drawings

E502-1, “Main One Line Diagram,” Revision 45

E582, “Turbine Generator Bldg, Ground Floor El. 441’ 0”, Power, Conduit and Tray Plan,” Revision 32

E814, “Transformer Yard Overhead Plan 1,” Revision 12

EWD-46E-259, “Electrical Wiring Diagram, AC Electrical Distribution System, Transformer yard Power Panel E-PP-2DB,” Revision 4

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Miscellaneous

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Procedures

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Work Orders

| | | | |
|---|---|---|---|
| 00002808 | 01064839-1 | 01175142-0 | 01153979 |

**B.2.47 Selective Leaching Inspection Program (XI.M33)**

Miscellaneous

Aging Management Program Evaluation Report for the Selective Leaching Inspection Program

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**B.2.49 Small Bore Class 1 Piping Inspection Program (XI.M35)**

Miscellaneous

Aging Management Program Evaluation Report for the Small Bore Class 1 Piping Inspection Program

Condition Report 2-05-02966

**Existing Programs**

**B.2.2 Air Quality Sampling Program (Plant Specific)**

Action Requests

| | | | | |
|---|---|---|---|---|
| 006172 | 013051 | 182962 | 225802 | 228631 |

Condition Reports

| | | | | |
|---|---|---|---|---|
| 2-05-03962 | 2-06-05132 | 2-06-05475 | 2-06-09144 | 2-07-07671 |

Problem Evaluation Requests

| | | |
|---|---|---|
| 202-0269 | 202-0693 | 202-1537 |

Procedures

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PPM 10.27.90, “DSA System Instrument Air Sampling,” Revision 2

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Work Orders

| | | | | |
|---|---|---|---|---|
| 01045966 | 01155517 | 01159055 | 01174079 | 01184269 |

**B.2.3 Appendix J Program (XI.S4)**

Miscellaneous

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**B.2.4 Bolting Integrity Program (XI.M18)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| 007766 | 178676 | 178979 | 181766 | 181969 | 185492 |

Condition Reports

| | |
|---|---|
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Miscellaneous

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Problem Evaluation Requests

| | | | |
|---|---|---|---|
| 203-1265 | 203-3526 | 203-3624 | 204-0169 |

Procedures

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PMP 10.2.13, “Approved Lubricants,” Revision 53

SYS 2-1, “Conduct of System Engineering Manual (COSEM),” Revision 1

**B.2.5 Buried Piping and Tanks Inspection Program (XI.M34)**

Drawings

C870, “Tower Makeup Water & Circulating Water Blowdown Piping Plan & Profile,” Revision 4

E804, “Make-up Water Supply Line & Pump House Plan & Details,” Revision 17

E811, “Cathodic Protection System Area Plan & Details, Sheet 1,” Revisions 11 and 12

E812, “Cathodic Protection System Area Plan & Details, Sheet 1,” Revisions 10 and 11

E840-2, “Cathodic Protection, Alarm System, Site Plan & Details Buildings 76-80 (Warehouses 1-5),” Revision 8

E1015, “Makeup Water Pump House Cathodic Protection System,” Revisions 2 and 3

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202-2754 203-1199 203-1246 203-4125 206-0598

**B.2.8 BWR Stress Corrosion Cracking Program (XI.M7)**

Miscellaneous

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B.2.11 BWR Water Chemistry Program (XI.M2)

Condition Reports

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Miscellaneous

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B.2.13 Closed Cooling Water Chemistry Program (XI.M21)

Condition Reports

2-05-01293 2-06-08211

Procedures

1.3.58, “Conduct of Chemistry,” Revision 17

12.14.12, “Reactor Closed Cooling Water,” Revision 7

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Miscellaneous

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**B.2.23 External Surfaces Monitoring Program (XI.M36)**

Miscellaneous

Action Request 227787

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Problem Evaluation Request 206-0136

Procedures

SYS-2-1, “Conduct of System Engineering Manual (COSEM),” Revision 1

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**B.2.25 Fire Protection Program (XI.M26)**

Action Requests

228550 228555

Drawings

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Miscellaneous

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Work Orders

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|---|---|---|---|---|---|
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| 01181721-01 | 01181726-01 | | | | |

**B.2.26 Fire Water Program (XI.M27)**

Drawings

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AED M515-5, “Flow Diagram - Fire Protection System,” Revision 4

AED M932-1, “Fire Main Ring Header,” Revision 1

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M515-1, “Flow Diagram - Fire Protection System,” Revision 103

M515-2, “Flow Diagram - Fire Protection System Details,” Revision 17

M515-4, “Flow Diagram - Fire Protection System,” Revision 1

M515-5, “Flow Diagram - Fire Protection System,” Revision 4

M545-1, “Flow Diagram - Heating Ventilation and Air Conditioning Reactor Building,” Revision 71

M573-2, “Flow Diagram - Potable Water Cold & Fire Protection Systems Pumphouses,” Revision 5

M650, “Composite Piping Circulating Water Pump House Sections & Details,” Revision 41

M658, “Composite Piping Circulating Water Pump House Plans,” Revision 60

M740, “Composite Yard Piping Plan,” Revision 42

M741, “Composite Piping Plan and Details Yard,” Revision 31

M742, “Composite Piping Plan and Details Yard,” Revision 16

M743, “Composite Piping Plans and Sections Yard,” Revision 16

M827, “HVAC Section and Details Radwaste and Control Building,” Revision 38

M861, “Temporary Facilities Yard Plan and Details,” Revision 33

M910, “Water Filtration Building Potable Water & Fire Protection Piping Arrangement,” Revision 20

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<u>Procedures</u>

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PPM 15.1.3, “FP-P-1 Operability Test,” Revision 17

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PPM 15.4.11, “Non-Essential Fire Barrier Functionality Inspection,” Revision 02

Work Orders

| | | | | | |
|---|---|---|---|---|---|
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| 01177438-01 | 01181721-01 | 01182026-01 | 01185362-01 | 01187062-01 | 01187463-01 |

**B.2.28 Flow-Accelerated Corrosion Program (XI.M17)**

Condition Reports

| | | | | | |
|---|---|---|---|---|---|
| 2-04-00445 | 2-05-03313 | 2-05-04457 | 2-07-04446 | 2-07-04783 | 2-07-05602 |

Miscellaneous

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|---|---|---|
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Procedures

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**B.2.29 Fuel Oil Chemistry Program (XI.M30)**

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D975-08, “Standard Specification for Diesel Fuel Oils”

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D2709–96, “Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge”

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Drawings

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Miscellaneous

Aging Management Program Evaluation Report for the Fuel Oil Chemistry Program

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Condition Report 2-05-06248

Design Change 83-0107-01, “Diesel Generator Fuel Sample Station,” – selected pages

Final Safety Analysis Report, Section 9.5.4

Regulatory Guide 1.137, “Fuel-Oil Systems for Standby Diesel Generators,” Revision 1

Standard ANS-59.51/ANSI N195-1976, “Fuel Oil Systems for Standby Diesel-Generators,” Revision 1

Technical Specification Bases 3.8.3.3, Revision 62

Technical Specification 5.5.9

White Paper on the Use of Ultra-Low-Sulfur Diesel Fuel at Columbia Generating Station and Applicability to License Renewal, dated March 10, 2010

Problem Evaluation Requests

| | | |
|---|---|---|
| 204-0877 | 206-0571 | 207-0081 |

Procedures

15.6.1, “Diesel Fire Pump Fuel Test,” Revision 6

CSP-DO-C101, “Diesel Generator New Fuel Test,” Revision 9

CSP-DO-M101, “Diesel Generator Storage Tank Fuel Test,” Revision 1

SWP-CHE-04, “Diesel Fuel Oil Testing Program,” Revision 0

B.2.31 High-Voltage Porcelain Insulators Aging Management Program (Plant Specific)

Action Requests

228661 228673

Drawings

S525, Sheet 1, “Structural Transformer Area Foundations,” Revision 5

S526, Sheet 2, “Structural Transformer Area Foundations,” Revision 3

Miscellaneous

1975 to 2002 Ecology Monitoring Program Summary Report

Aging Management Program Evaluation Report for the High-Voltage Porcelain Insulators Aging Management Program

Plant Tracking Log Item 33182

Work Order Instruction 01150308, “115KV Insulators - Clean to Remove Mineral”

Operating Experience

EN 45833, “Actuation of Blackout Sequencers due to Loss of One Offsite Power Source”

Licensee Event Report 89-002-00, “Turbine Control Valve Fast Closure Reactor Scram Due to Main Generator Trip Caused by Equipment Failure - Shorted Main Transformer Output Line Insulator,” dated February 18, 1989

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OE30804, “345 kV Switchyard Circuit Breaker Porcelain Bushings Experienced Weather Related Cracking (Callaway)”

**B.2.34 Inservice Inspection Program – IWE Program (XI.S1)**

Condition Reports

2-07-04824 2-07-05810

Miscellaneous

Action Request 197488

Aging Management Program Evaluation Report for the Inservice Inspection Program – IWE Program

Containment Visual Examination Data Sheet, Report No 3COV-23, dated May 19, 2009

Drawing 213-00, 331, "Primary Containment Vessel Nuclear Project No 2, Richland Washington Equipment Hatch (Penetration 15)," Revision 0

Final Safety Analysis Report, Figure 3.8-26, "Primary Containment Vessel Drywell Refueling Bellows Seal"

Information Notice 1988-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," dated October 14, 1988

ISI/NDE Examination Data Sheet, Evaluation Sheet No. 3-004, dated June 9, 2007

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Letter GO2-04-149, "Commitment Clarification Sand Pocket Drain Humidity Monitoring," dated August 31, 2004

Procedures

10.24.206, "Containment Annulus Sand Pocket Humidity Measurement," Revision 4

ISI-3, "Inservice Inspection Program Plan - Interval 3," Revision 3

SPS-7-4, "Visual Examination of Containment," Revision 1

Work Orders

| | | | | |
|---|---|---|---|---|
| 01140315-01 | 01125391-01 | 01133954-01 | 01135240-01 | 01145169-01 |

**B.2.36 Lubricating Oil Analysis Program (XI.M39)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| 182276 | 202374 | 209263 | 209864 | 223791 | 228715 |

Audits and Assessments

SA-2004-10, "Oil Analysis Self Assessment"

Self Assessment 209263, "Component Condition Monitoring Program"

Audit Report AU-CH-10, "Chemistry, Environmental and Effluents Monitoring Programs"

Miscellaneous

Aging Management Program Evaluation Report for the Lubricating Oil Analysis Program

Plant Tracking Log Items A238625 and A238635

Quality Assurance Manual for the Analytical Laboratory

Supplemental Analytical Laboratory Instruction (SALI) G02, "Analysis of wear metals in petroleum products using ICP-OED," Revision 6

Work Request 29027958

Problem Evaluation Requests

202-3108 202-3183 202-3374

Procedures

PPM 1.19.3, "Component Condition Monitoring," Revision 3

PPM 1.19.3C, "Lubrication Analysis," Revision 3

**B.2.38 Masonry Wall Inspection Program (XI.S5)**

Miscellaneous

Aging Management Program Evaluation Report for the Masonry Wall Inspection Program

American Concrete Institute 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures"

American Concrete Institute 201.1R-08, "Guide for Conducting a Visual Inspection of Concrete in Service"

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Procedure PPM 1.5.11, "Maintenance Rule Program," Revision 10

**B.2.42 Open-Cycle Cooling Water Program (XI.M20)**

Action Requests

017029 204617 209097 210284

Assessments

SA-2007-0038, "Assessment of Standby Service Water Corrosion Monitoring Program," dated August 24, 2007

SA-2007-0060, “Assess Generic Letter 89-13 Commitments,” dated September 25, 2007

SR-09-09, “Heat Exchanger Program,” dated December 31, 2009

<u>Heat Exchanger Test Results</u>

PPM 8.4.42, “Thermal Performance Monitoring of RHR-HX-1A,” completed April 9, 2007

PPM 8.4.42, “Thermal Performance Monitoring of RHR-HX-1B,” completed April 9, 2007

PPM 8.4.42, “Thermal Performance Monitoring of RHR-HX-1A,” completed May 5, 2009

PPM 8.4.42, “Thermal Performance Monitoring of RHR-HX-1B,” completed May 5, 2009

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PPM 8.4.54, “Thermal Performance Monitoring of DCW-HX-1A1 And DCW-HX-1A2,” completed April 20, 2010

PPM 8.4.62, “Thermal Performance Monitoring of DCW-HX-1B1 And DCW-HX-1B2,” completed July 24, 2008

PPM 8.4.62, “Thermal Performance Monitoring of DCW-HX-1B1 And DCW-HX-1B2,” completed October 20, 2009

PPM 8.4.63, “Thermal Performance Monitoring of DCW-HX-1C1,” completed September 22, 2009

PPM 8.4.63, “Thermal Performance Monitoring of DCW-HX-1C1,” completed July 4, 2010

TSP-SW-A101, “Service Water Loop A Cooling Coil Heat Load Capacity Test,” completed September 9, 2009

TSP-SW-A101, “Service Water Loop A Cooling Coil Heat Load Capacity Test,” completed June 4, 2010

TSP-SW-A102, “Service Water Loop B Cooling Coil Heat Load Capacity Test,” completed May 5, 2009

TSP-SW-A102, “Service Water Loop B Cooling Coil Heat Load Capacity Test,” completed April 7, 2010

<u>Letters</u>

GO2-89-205, “Response to Generic Letter 89-13, ‘Service Water System Problems Affecting Safety Related Equipment,’” dated November 9, 1989

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GO2-91-041, “Response to Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment,’” dated March 28, 1991

<u>Miscellaneous</u>

90 day and 180 day Corrosion Coupon Results since December 6, 1999

Aging Management Program Evaluation Report for the Open-Cycle Cooling Water Program

“Biofouling Control in an Open Recirculating Service Water System Using Hydrogen Peroxide”

Chemistry Trend Graphs for Service Water System

Composite Drawing Depicting Minimum Point Graphs and Data for 19 points

Containment Atmosphere Control System Deactivation Documentation

Electric Power Research Institute Report TR-106229, “Service Water System Chemical Addition Guideline,” dated July 1996

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

Heat Exchanger Program, Revision 5

Heat Exchanger Test Trend Graphs

Heat Exchanger Program Health Reports, 1st and 2nd Quarters 2010

Licensee Event Report 93-031-01, “Main Control Room HVAC [Heating, Ventilation, and Air Conditioning] High Temperature Condition during a Design Basis Accident,” dated January 7, 1994

Microbiologically Induced Corrosion (MIC) Monitoring Program

NRC Inspection Report Nos. 50-397/95-26, 50-397/96-02, and 50-397/96-06

Room Cooler Photographs Demonstrating Condition of Coils

Room Cooler, Residual Heat Removal Pump Motor, and High Pressure Core Spray Motor Heat Exchanger Cooling Coil Drawings

Service Water System Health Reports, 1st Quarter 2009 through 2nd Quarter 2010

Service Water Reliability Program, Revision 5

Technical Memorandum TM-2111, “Thermal Performance Testing of Air-To-Water Heat Exchangers in the WNP-2 SW [*Service Water*] System,” Revision 0

Technical Specification 3.7.1

Tube Plugging Maps for the In-Scope Heat Exchangers

Ultrasonic Test Data for the Service Water Spray Pond Siphon Line, dated September 17, 2008

Ultrasonic Test Result Trend Graphs for the Residual Heat Removal, Diesel Generator Jacket Water, and Fuel Pool Cooling Heat Exchangers

Problem Evaluation Requests

| | |
|---|---|
| 293-0140 | 202-1977 |

Procedures

PPM 8.4.42, “Thermal Performance Monitoring of RHR-HX-1A and RHR-HX-1B,” Revision 7

PPM 8.4.54, “Thermal Performance Monitoring of DCW-HX-1A1 and DCW-HX-1A2,” Revision 8

PPM 8.4.62, “Thermal Performance Monitoring of DCW-HX-1B1 and DCW-HX-1B2,” Revision 7

PPM 8.4.63, “Thermal Performance Monitoring of DCW-HX-1C,” Revision 7

SWP-CHE-02, “Chemical Process Management and Control,” Revision 16

Work Orders

| | | | | |
|---|---|---|---|---|
| 01094834-04 | 01094834-05 | 01138420-01 | 01178799-01 | 01186396-01 |

**B.2.44 Preventive Maintenance – RCIC Turbine Casing Program (Plant Specific)**

Miscellaneous

Aging Management Program Evaluation Report for the Preventive Maintenance – RCIC Turbine Casing Program

LRAMR-18, “Aging management Review for the Reactor Core Isolation Cooling System,” Revision 2

Problem Evaluation Request 205-0429

Procedures

BID-TURB-2, “Preventive Maintenance Background Information, Reactor Core Isolation Cooling Turbine,” Revision 0

PPM 10.7.1, “Reactor Core Isolation Cooling Turbine (RCIC-DT-1) Inspection/Repair/Overhaul,” Revision 11

PPM 10.2.10, “Fastener Torque and Tensioning,” Revision 23

Work Orders:

| | | | | |
|---|---|---|---|---|
| 01066644 | 01069221 | 01113759 | 01113774 | 01007947 |

**B.2.50 Structures Monitoring Program (XI.S6)**

Action Requests

| | | | |
|---|---|---|---|
| 026719 | 031540 | 179589 | 228723 |

Miscellaneous

Aging Management Program Evaluation Report for the Structures Monitoring Program

American Concrete Institute 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures"

American Society of Civil Engineers 11-90, "Guideline for Structural Condition Assessment of Existing Buildings," dated August 1991

Burns & Roe Vendor/Contractor Concrete Placement Procedures

Draft NRC Audit Report of Aging Management Programs, completed May 28, 2010

Drawings Related to Reactor Building Elevations West Wall, Floor Plans Elevation 578', and Typical Construction Joint Details

Final Safety Analysis Report, Sections 3.7, "Seismic Design," and Figure 9.4-11, "Reactor Building"

Procedure PPM 1.5.11, "Maintenance Rule Program," Revision 10

Quality Assurance Inspection Report No. A1-6-78-2

Request for Additional Information B2.1.32-1 and applicant response

**B.2.53 Water Control Structures Inspection Program (XI.S7)**

Action Requests

| | | |
|---|---|---|
| 031540 | 026719 | 034432 |

Miscellaneous

Aging Management Program Evaluation Report for the Water Control Structures Inspection Program

American Concrete Institute 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures"

American Society of Civil Engineers 11-90, “Guideline for Structural Condition Assessment of Existing Buildings,” dated August 1991

Draft NRC Audit Report of Aging Management Programs, completed May 28, 2010

Procedure PPM 1.5.11, “Maintenance Rule Program,” Revision 10

Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” Revision 1

Request for Additional Information B2.1.53-1 and applicant response

**System Reviews**

**Compressed Air and Gas, Diesel Generator Starting Air and Lubricating Oil, High Pressure Core Spray, Standby Service Water, and Reactor Core Isolation Cooling**

**Compressed Air and Gas**

Drawings

LR-M510-2A, “Control and Service Air Systems Gas Tables and Details,” Revision 0

M510-3, “Flow Diagram Control Service and Breathing Air Systems,” Revision 24

M556-1, “Flow Diagram Containment Instrument Air System,” Revision 50

M556-2, “Flow Diagram Containment Instrument Air System,” Revision 3

Miscellaneous

Design Specification for Division 9, Section 9B.2 Finish Painting, Revision 3

WNP-2 Instrument Master data Sheet, SW-LS-1A5, Revision 7

Vendor Manual PD-311.1, “Platinum Resistance Temperature Sensors, RTS-31 & RTS-32,” dated April 17, 1979

**Diesel Generator Starting Air and Lubricating Oil**

Drawings

LR-M512-2, “License Renewal Boundary Drawing Diesel Oil & Miscellaneous Systems Diesel Generator Building,” Revision 0

LR-M512-2, “License Renewal Boundary Drawing Diesel Oil & Miscellaneous Systems Diesel Generator Building,” Revision 0

Miscellaneous

LRAMR-M10, Attachment 1.6, “Aging Management Review Results for the DSA System,” Revision 3

LRAMR-M10, Attachment 1.4, “Aging Management Review Results for the DLO System,” Revision 3

Manufacturers’ Data Report for Pressure Vessels, September 1975

CVI 53-00.68.4, “Replacement Parts Catalog For Diesel Engine 645”

**High Pressure Core Spray**

Miscellaneous

Drawing 049058, “Component Material Identification,” Revision 2

**Reactor Core Isolation Cooling**

Drawings

LR-M519, “Reactor Core Isolation Cooling (RCIC) System,” Revision 0

CVI-02E51-07, Sheet 37, “Table III Terry Steam Turbine Instruction”

CVI 215-09, Sheet 148, “Valve ASSY-1inch Y-Type 1500 Lb, Globe, SW, CS, Air Operated, Fail Closed”

CVI 02E51-07, Sheet 23, “Assembly of CSM 40 ‘Gingle Gland Exhaust Pump with barometric Condenser”

**Standby Service Water**

Action Requests

227597 227680 228028 228718

Drawings

ED-SW-1, “Standby Service Water Piping (Spray Pond 1A),” dated March 288, 1978

LR-M524-1, “Standby Service Water System Reactor, Radwaste, Diesel Generator Buildings, and Yard,” Revision 0

LR-M524-2, “Drawing Standby Service Water System Reactor, Radwaste, Diesel Generator Buildings, and Yard,” Revision 0

LR-M524-3, “Standby Service Water System Reactor, Radwaste, Diesel Generator Buildings, and Yard,” Revision 0

M740. “Composite Yard Piping Plan,” Revision 42

M741. “Composite Piping Plan and Details Yard,” Revision 31

M742, “Composite Piping Plan and Details Yard,” Revision 16

M782, “Composite Piping Plan, Sections and Details Spray Pond,” Revision 14

M783. “Flow Diagram Primary Containment $N_2$ Inerting System,” Revision 42

M831, “Embedded Piping, Floor, Equipment & Miscellaneous Drains Radwaste Building Plan El. 437’-0”,” Revision 27

M832, “Embedded Piping, Floor, Equipment & Miscellaneous Drains Radwaste Building Plan El. 437’-0” & El. 452’-0”,” Revision 23

Miscellaneous

LRAMR-M07, “Aging Management Review of the Service Water Systems,” Revision 3

LRAMR-S01, “Structures Screening and Aging Management Review of the Standby Service Water Pump Houses and Spray Ponds,” Revision 2

Work Orders

01071427-01 01124698-01