UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4511

September 24, 2012

Michael Perito
Site Vice President Operations
Entergy Operations, Inc.
Grand Gulf Nuclear Station
P.O. Box 756
Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION - NRC LICENSE RENEWAL INSPECTION REPORT 05000416/2012007

Dear Mr. Perito:

On August 23, 2012, a U.S. Nuclear Regulatory Commission team completed the onsite portion of an inspection of your application for license renewal of your Grand Gulf Nuclear Station. The team discussed the inspection results with Mr. J. Browning, General Manager Plant Operations, and other members of your staff during an exit meeting on August 23, 2012.

This inspection examined activities that supported the application for a renewed license for the Grand Gulf Nuclear 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 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/

Geoffrey Miller, Chief
Engineering Branch 2
Division of Reactor Safety

Docket: 50-416
License: NPF-29

Enclosure:
NRC Inspection Report 05000416/2012007
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	05000416
License:	NPF-29
Report:	05000416/2012007
Applicant:	Entergy Operations, Inc
Facility:	Grand Gulf Nuclear Station
Location:	Port Gibson, MS
Dates:	August 6 through August 23, 2012
Inspectors:	S. Graves, Senior Reactor Inspector and Team Leader G. Meyer, Senior Reactor Inspector G. Pick, Senior Reactor Inspector B. Correll, Reactor Inspector C. Hale, Reactor Inspector
Approved By:	G. Miller, Chief Engineering Branch 2 Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000416/2012007; 8/06/2012 — 8/23/2012; Grand Gulf Nuclear Station, License Renewal Inspection

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 systems, structures, 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. <u>NRC-Identified and Self-Revealing Findings</u>

No findings were identified.

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

None.

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. Scoping activities are those 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 24 of the 44 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. In-scope refers to 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 systems, structures and components 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. 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 in-plant areas, including the Diesel Generator Building, Reactor Enclosure, Component Cooling Water Heat Exchangers, Standby Service Water Cooling Tower and Basin, and the Fire Water Pumphouse.

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. As part of in-plant walk downs, the team selected specific components to confirm that the components had been scoped properly and included accurately in the drawings and database. 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 walk downs 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 team noted an inconsistency regarding the piping to the gland seal system for the reactor core isolation cooling (RCIC) system. The piping had been included in the license renewal scope, but the gland seal system had screened out. On further review the applicant determined that the gland seal system was not a condensing system as had been originally assumed but a compressed air system; the review also determined that structural anchors existed on the piping. Based on this review the applicant determined that correct categorization should have been to remove the gland seal system and the non-safety piping beyond the structural anchors from scope, and that an additional environment should be added to the RCIC aging management review. Entergy issued Condition Report CR 2012-10047 to address these changes and planned to submit an application change to revise Table 3.2.2-4, "Summary of Aging Management Evaluation," for the RCIC aging management review. The team determined that these changes were appropriate and represented an isolated error in the scoping results.

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 Evaluation of New Aging Management Programs

The team reviewed 7 of 10 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 are present, 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.1.1 115-kV Inaccessible Transmission Cable (Plant-Specific)

This was a new, plant-specific condition monitoring program that will manage the effects of aging on the 115 kV inaccessible transmission cables. The program will manage reduced insulation resistance caused by moisture and voltage stress of power cables installed in wetted environments. The cables managed by this plant-specific program were separated from the Non-EQ Inaccessible Power Cables program because of the differences in cable construction. The cables are high-voltage cables installed in underground conduit or duct banks, rated for 138 kV, with single 500 MCM aluminum conductors and cross-linked polyethylene insulation.

There was no corresponding GALL Report entry for this plant-specific program; however, elements of the program were compared to the ten elements described in Table A.1-1 of Revision 1 to the Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants. The program will be implemented and the first cable tests and manhole inspections will be completed prior to the period of extended operation. The program will periodically inspect the manhole (MH-15) containing the in-scope 115 kV inaccessible transmission cables at least annually, with the periodicity to be shortened if periodic inspection results indicate the need to increase the inspection frequency. The program will also test the transmission cable insulation every 6 years to provide an indication of the condition of the cable insulation properties.

The team reviewed license renewal documentation, the aging management program evaluation report as described in GGNS-EP-08-LRD08," Aging Management Program Evaluation Results – Electrical," Revision 1, conducted transmission system walk downs and held discussions with the applicant's engineering staff concerning the 115 kV transmission system.

The applicant implemented a design modification to install a solar powered sump pump in the manhole (MH-15) to maintain water below the cables and support structures. A change to the license renewal application had also been made to include corrective actions when the manhole inspection acceptance criteria were not met to perform an engineering evaluation to ensure the intended functions of the electrical cables can be maintained consistent with the current licensing basis.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent plant and industry operating experience, and that the proposed program guidance would appropriately identify and address aging effects during the period of extended operation.

.2 B.1.2 Aboveground Metallic Tanks (XI.M29)

The Aboveground Metallic Tanks program is a new program that will be consistent with the program described in the GALL Report. The program is credited with managing the loss of material for the outer surfaces, including the bottom surfaces, of aboveground metallic tanks through visual inspections of the outer surface of the tanks and thickness measurements of the tank bottoms. The three tanks at Grand Gulf Nuclear Station within the scope of the program are the condensate storage tank and the two fire water storage tanks.

The team reviewed license renewal documents, the aging management program evaluation report, corrective action documents, technical specifications and drawings for the tanks, and procedures and results of the current external inspections of the tanks. The team walked down each of the tanks and discussed the condition of the tanks with program and system engineers. The team verified that the applicant planned to perform ultrasonic testing (volumetric) to determine thickness measurements of tank bottoms whenever the tanks are drained and at least once within five years of entering 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.

During the walkdown of the fire water storage tanks the team noted that a contoured portion of each of the tanks was located inside the fire water pump house. The team questioned the applicant’s ability to meet the requirements of the program to inspect the entire outer surface, as stated in the GALL Report, when a portion of the tank surface was obstructed by the roof of the pump house, and was not easily visible. The applicant confirmed that procedures to implement the new program will include inspection of the entire exterior surface of the tank, including the portion of the tank that is not easily accessible. The applicant had not developed detailed procedures but discussed their intent to use scaffolds or mirrors if necessary to inspect the entire exterior surface of the tank, including the portion of the tank near the roof.

The team also noted that fire water storage tank B had staining that appeared to be rust and appeared to originate at the location of the roof and tank interface, running down the length of the tank inside the fire water pump house. The applicant initiated Condition Report CR 2012-1008 to identify the cause of the rust stains. The team also observed extensive rust on the bottom flange portion of fire water storage tank B inside the fire water pump house. The applicant identified that Work Order 190619 had been written following the previous external inspection in 2011 to correct the corrosive condition and make needed repairs to the tank. The team considered these corrective actions appropriate to determine the cause of the rust stains on the tank, correct the rust on the bottom flange portion of the tank, and evaluate any additional aging effects on the tank.

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 developed guidance to appropriately identify and address aging effects during the period of extended operation.

.3 B.1.5 Buried Piping and Tanks Inspection (XI.M34)

The applicant established this new aging management program, consistent with the GALL Report and final license renewal interim staff guidance LR-ISG-2011-03, "Changes To The Generic Aging Lessons Learned (Gall) Report Aging Management Program XI.M41, Buried And Underground Piping And Tanks," Revision 2, to detect the aging of external surfaces of buried and underground piping and tanks composed of any material through preventive, mitigative, and inspection activities. The applicant identified that they would manage the aging effect of loss of material by monitoring wall thickness of piping and tanks and the visual appearance of piping or tank exteriors. Wall thickness will be determined by a non-destructive examination technique such as ultrasonic testing. Pipe-to-soil potential and cathodic protection current will be monitored for piping and tanks in contact with soil for those components with cathodic protection. The applicant's aging management program identified that all buried and underground piping and tanks, regardless of their material of construction, will also be inspected by visual means whenever they become accessible for any reason (opportunistic inspection). The program will use the methods and frequencies for direct inspections consistent with those outlined in the "Detection of Aging Effects" element of NUREG-1801 XI.M41 as updated in the final license renewal interim staff guidance LR-ISG-2011-03. Adverse indications will be addressed in accordance with this element.

This program covered several systems, including standby service water, standby diesel generators, fire water, fire protection CO_2 and Halon; parts of the high pressure core spray diesel generator system, and the condensate and refueling water storage and transfer systems.

The team reviewed license renewal documents, the aging management program evaluation report, industry operating experience, corrective action documents, cathodic protection system evaluation reports, backfill specifications, applicant procedures, system health reports and industry guidance. The team interviewed engineers responsible for the underground piping and tanks program and the cathodic protection system.

The applicant had developed an underground piping and tanks inspection and monitoring program using appropriate industry standards, guidance in Nuclear Energy Institute 09-14, "Guideline for the Management of Underground Piping and Tank Integrity," and Entergy fleet operating experience.

The team determined that in 2009 the applicant had upgraded their cathodic protection system by installing six deep anode ground beds and rectifier assemblies to improve system reliability. Prior to installation of the new system the vendor performed a Native Area Potential Earth Current survey to determine the native corrosion state of buried plant piping and tanks. Area potential measurements were taken to determine the corrosion condition or cathodic protection state of buried piping and structures. Earth current measurements were taken to provide an indication of the condition of external coatings of these structures. The initial survey results did not find any unusual conditions, however the survey did identify the potential existence of local corrosion cells in several general areas. After installation of the six new cathodic protection rectifiers and deep anode ground bed systems an Interrupted Area Potential Earth Current survey was performed by the vendor. The interrupted survey identified that 93 percent of the plant areas surveyed were receiving at least the minimum level of polarization (100 millivolts) for corrosion protection as identified in National Association of Corrosion Engineers standard SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." The remaining seven percent included an area just east of the standby cooling water basins (an in-scope system) that had a higher possibility of coating damage based on the survey results. The vendor recommended two approaches for improving the corrosion protection in this area: (1) increase the output current from rectifier number 1 to the maximum value, and (2) perform opportunistic piping inspections in this area to validate the condition of piping and coatings. The applicant entered this issue into their corrective action program as Condition Report CR 2010-01376, which documented the vendor recommendations, the adjustment of rectifier number 1 to the maximum current output, and the need to perform opportunistic inspections of the piping in these areas to validate both the coating condition and the survey results. The team determined that the applicant had completed their risk ranking of piping included as part of these recommendations and susceptible piping systems had been appropriately captured in the ranking. The applicant had begun developing a schedule for performing inspections but inspections had not been completed.

The team confirmed that the installed cathodic protection system was operating properly and provided appropriate protection for in-scope buried piping. The applicant had committed to adding additional information to the license renewal application Table A.1.5, "Buried Piping and Tanks Inspection Program," to reflect that the cathodic protection system is used for additional protection of buried piping and tanks, and the system will be monitored and trended annually in accordance with National Association of Corrosion Engineers standards SP-0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," and RP-0285, "Corrosion Control of Underground Storage Tank Systems by Cathodic Protection."

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

.4 B.1.28 Non-EQ Cable Connections (XI.E6)

This is 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 program will 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 will evaluate a representative sample of electrical cable connections based upon the service application (medium and low voltage), circuit loading (high loading), and environment (high temperature, high humidity, vibration, radiation), document the technical basis for the sample selected and the acceptance criteria used for each inspection.

The team reviewed license renewal documents and the aging management program evaluation report. Because this was a new one-time inspection, the applicant had not fully developed their inspection program. The team determined that the applicant planned to implement the process described in GGNS-EE-08-AME01, "Aging Management Review of Electrical Systems," Revision 0. The applicant specified they would evaluate a representative sample of the various electrical cable connections exposed to differing environments throughout the facility.

The team concluded that the applicant performed appropriate evaluations and considered pertinent industry operating 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 confirm whether aging effects had occurred prior to the period of extended operation.

.5 B.1.31 Non-EQ Insulated Cables and Connections (XI.E1)

This was a new aging management program, consistent with the GALL Report, credited with managing aging effects on insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture.

The applicant defined adverse localized environments as a limited plant area that had conditions significantly more severe than the plant design environment for the cable or connection insulation materials. The aging effects being reviewed include surface anomalies such as embrittlement, cracking, discoloration, crumbling, melting, swelling or any other visual evidence of surface contamination, or other visible degradation. The applicant specified they would 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, and plant operating experience. 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 specified that their program would use the guidance in Electric Power Research Institute Report TR-109619, "Guideline for Management of Adverse Localized Environments." The applicant specified 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 B.1.33 One-Time Inspection (XI.M32)

The applicant established this new aging management program, consistent with the GALL Report, to manage loss of material, cracking, and reduction of heat transfer internal to plant systems. The applicant will conduct these one-time inspections to identify and characterize the material conditions in representative low flow and stagnant areas of plant piping and components addressed by the Water Chemistry, the Diesel Fuel Monitoring, and the Oil Analysis programs. 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. The inspection also provides direct evidence of any cracking as a result of stress corrosion.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and Entergy-wide program procedures. The team discussed the program evaluations and planned activities with the responsible license renewal and plant staff. The applicant specified that the sampling plan would be consistent with that specified in the GALL Report, Revision 2, Section XI.M32, "One-Time Inspection" and noted that the current program procedure was not consistent with this sampling and would need revision prior to implementation at Grand Gulf. The team confirmed that appropriately qualified personnel will perform the nondestructive evaluations by using procedures and processes that met regulatory 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.

.7 B.1.40 Selective Leaching (XI.M33)

The applicant established this new aging management program, consistent with the GALL Report, to detect the aging of components subject to selective leaching of materials. The affected components included material made of gray cast iron and copper alloys with greater than 15 percent nickel or 8 percent aluminum (i.e., bronze or brass) exposed to raw water, treated water, and ground water. The program will include a one-time visual inspection and mechanical testing of a sample of components with metallurgical properties susceptible to selective leaching to determine whether loss of material had occurred. The program will also evaluate whether selective leaching would affect the ability of the components to perform their intended function in the event of graphitization of gray cast iron or dezincification of copper alloys with greater than 15 percent zinc during the period of extended operation. The applicant noted that there were no aluminum bronze components installed at Grand Gulf Nuclear Station.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and an Entergy-wide program procedure. The team discussed the program evaluations and planned activities with the responsible license renewal and plant staff. The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effect 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.

b.3 Evaluation of Existing Aging Management Programs

The team sampled 17 of the 34 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 effects 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 <u>B.1.13 Containment In-service Inspection - IWE (XI.S1)</u>

This was an existing program, consistent with the GALL Report, credited with managing aging effects related to loss of material, loss of integrity, and leak tightness 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 visual inspection included the steel containment liner and integral attachments, containment hatches and airlocks, and pressure-retaining bolting. The applicant inspected for: (1) bending, twisting, stretching or deforming bolts or studs; (2) missing or loose bolts, studs, nuts, or washers; (3) fractured bolts, studs, or nuts; (4) degraded protective coatings on bolting surfaces; (5) evidence of coolant leakage near bolting; (6) localized excessive corrosion; and (7) misalignment of connections or bolting. The applicant evaluated the aging effects of pressure-retaining seals and gaskets in accordance with their containment leak rate program.

The applicant augmented this program with existing procedures to ensure appropriate selection of bolting material, installation torque or tension, and the use of lubricants for the intended purpose. These procedures referenced bolting guidance contained in documents issued by the industry and the NRC to ensure proper identification and use of bolting material, lubricants, and torque values.

The team reviewed license renewal documents, the aging management program evaluation report, industry and plant operating experience related to containment liners, corrective action documents, and previous containment liner inspection results. The team walked down and evaluated the condition of the containment liner, including its integral attachments and bolting.

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 address aging effects during the period of extended operation.

.2 <u>B.1.15 Containment Leak Rate (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 loss of material, cracking, and loss of function in the primary containment shell and associated welds, air locks, hatches and containment penetrations (mechanical, electrical, instrument and control), and blind and testable flanges. The program also provided for detection of age-related degradation in material properties of gaskets, o-rings, and packing materials for the primary containment pressure boundary access points.

The applicant performed containment leakage rate tests to assure that leakage through the containment and systems and components penetrating primary containment did not exceed allowable leakage limits specified in the licensing basis documents and technical specifications. The applicant performed the integrated leak rate test, while shutdown, in accordance with 10 CFR Part 50, Appendix J, which demonstrated the leak-tightness and structural integrity of the containment. Similarly, the applicant performed local leak rate tests on isolation valves and containment access penetrations.

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 responsible engineer and also verified that the applicant implemented their leakage rate program in accordance with 10 CFR Part 50, Appendix J, Option B, and relevant industry guidance. 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 local leak rate tests at the frequencies allowed by their program and regulatory requirements. For components not included in the performance-based integrated leak test program, the team determined that the applicant had conducted appropriate tests at the required frequency.

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 address aging effects during the period of extended operation.

.3 B.1.16 Diesel Fuel Monitoring (XI.M30)

This was an existing program consistent with the GALL Report after enhancement, credited with managing the aging effects due to general, pitting, crevice, and microbiological influenced corrosion (MIC) on internal surfaces of the diesel fuel oil system piping, piping components, and tanks by minimizing exposure to fuel oil contaminated with water and microbes. The first enhancement provides that cleaning and internal inspections will be performed every 10 years on in-scope fuel oil tanks beginning in the 10 years prior to the period of extended operation. The second enhancement provides that degradation noted during the inspections will be evaluated by volumetric examination.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and drawings for buried fuel oil tanks. The team reviewed fuel oil sampling, tank bottom draining, and tank inspection procedures, including completed inspections and chemistry results, and applicable corrective action documents. The team reviewed a database search of condition reports on the fuel oil storage tanks for diesel fire pumps since 2008. The team walked down accessible fuel oil components on the Division I and Division III emergency diesel generators, and the A and B diesel fire pumps. The team discussed the procedures, evaluations, and results with the responsible license renewal and plant 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 on piping and component surfaces in diesel fuel oil systems. The team concluded that, if implemented as described including enhancements related to periodic cleaning and inspections, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.4 B.1.18 External Surfaces Monitoring (XI.M36)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing aging effects through visual inspection of external surfaces for evidence of loss of material, cracking and change in material properties. The program was also credited with managing aging effects on the internal surfaces of components for situations in which material and environment combinations are the same for internal and external surfaces such that the external surface condition is representative of the internal surface condition. The applicant used visual inspections during periodic engineering walkdowns to monitor for material degradation and leakage. The program inspected components such as piping, piping components, ducting, and polymeric components. The program specified that aging effects for flexible polymeric components may be monitored through a combination of visual inspection and manual or physical manipulation of the material. The applicant defined "manual or physical manipulation of the material" to mean touching, pressing on, flexing, bending, or otherwise manually interacting with the material in order to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, and system engineer qualification procedures. The applicant specified they would enhance the external surfaces monitoring program to include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of available surface area. The program will also be enhanced to include: (1) underground components within the scope of the program will be clearly identified in program documents, and these components are those for which access is physically restricted; and (2) instructions will be provided for inspecting all underground components within the scope of this program during each five year period, beginning ten years prior to the entry into the period of extended operation.

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 address aging effects during the period of extended operation.

.5 <u>B.1.20 Fire Protection (XI.M26)</u>

This was an existing program, consistent with the GALL Report after enhancement, credited with managing cracking, loss of material, and change in material properties through visual inspection of components and structures with a fire barrier intended function. The in-scope items included penetration seals, fire barrier walls, ceilings, and floors, and all fire-rated doors that perform a fire barrier function. The program was also credited with managing loss of material for the CO_2 and Halon fire suppression systems through periodic visual inspection and testing.

The applicant specified they would manage the effects of aging through visual inspections of fire barriers, fire-rated penetration seals, fire wraps, fire proofing, and fire-rated doors. The applicant visually inspected at least 10 percent of each type of fire-rated penetration seal every 18 months; visually inspected required fire-rated doors and functionally tested the release, closing mechanism and latches every 6 months; visually inspected the exposed external surfaces of fire barriers, fire wraps, and fire proofing for abnormal degradations or changes in appearance that could affect the barrier function every 18 months; performed system functional testing for the fire suppression water system every 18 months including verification that each required fire suppression pump started sequentially upon a continued pressure drop in the fire suppression water system.

The applicant's program will be enhanced to require visual inspections of the Halon and CO_2 fire suppression systems at least once every fuel cycle to examine for signs of corrosion. The program will be enhanced to require visual inspections of fire damper framing at least once every fuel cycle to check for signs of degradation, and enhanced to require visual inspections of concrete curbs, manways, hatches, manhole covers, hatch covers, and roof slabs at least once every fuel cycle to confirm that aging effects are not occurring.

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 external CO_2 storage tank and associated piping and in-plant Halon and CO_2 systems.

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

.6 <u>B.1.21 Fire Water System (XI.M27)</u>

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the loss of material and fouling for components in fire protection systems using preventive, inspection, and monitoring activities, including periodic full flow flush tests, and testing or replacement of sprinkler heads. The applicant implemented the program consistent with applicable industry standards and guidance documents. This program included fire water system piping and components such as pump casings, sprinkler heads, standpipes, orifices, 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 condition reports. The team interviewed plant personnel and walked down fire water system equipment, including the fire pumps and associated piping. The team verified that plant maintenance procedures periodically tested hoses and replaced gaskets as required by their technical requirements manual. The team verified that the applicant maintained and continuously monitored the pressure in the fire protection system. The team verified that the applicant had established appropriate parameters to verify flow through the fire protection supply piping and reviewed completed flow surveillance tests.

The applicant planned to enhance this program to: (1) periodically inspect spray and sprinkler system internals visually for degradation; (2) periodically inspect hose reels for degradation; (3) visually inspect a representative sample (i.e., 20 percent up to 25 locations of the same material, environment and aging effect combination) of the interior surface of below grade piping (additional inspections will be performed as necessary to obtain the sample); (4) replace sprinkler heads at 50 years or test a representative sample of sprinkler heads at 10 year intervals; and (5) for above grade piping, either use non-intrusive volumetric tests to identify loss of material and establish an appropriate inspection interval or perform internal surface inspections during routine or corrective maintenance. These internal inspections must be capable of determining the wall thickness and inner diameter of the piping of a representative sample of above ground piping similar to that described for below grade piping. For all enhancements the applicant will establish acceptance criteria that evaluates for no unacceptable degradation.

The team determined that the applicant planned to establish appropriate methods to select the sample size for both the above and below grade fire water system piping. The team verified that plant procedures required inspecting hoses including the hose gaskets. The team determined that the applicant would need to add a requirement to inspect for aging effects on the hose reels. The team determined that the applicant considered a representative sample of sprinkler heads for inspection which would result in evaluating one percent or a minimum of four sprinklers for a given environment. The team questioned the proposed frequency of periodic inspections of the spray and sprinkler system internals, and the applicant responded that they would revise their aging management program evaluation report to perform an engineering evaluation to establish the frequency of inspections of spray and sprinkler systems. The team verified that the applicant identified an action to replace their sprinkler heads or establish a 10 percent sampling plan at a frequency established through an engineering evaluation. The licensee documented the requirement to change their aging management program evaluation report as Follow-up Item 657 in their license renewal database.

The applicant performed the following activities as specified in the technical requirements manual: (1) flow testing of the fire water supply piping and continuous monitoring of system pressure; (2) hydrostatic testing, flushing to remove debris, and visually inspecting essential yard fire hydrants and associated hoses; (3) visually inspecting and replacing, if necessary power block fire hoses and gaskets, and (4) 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 and clarifications to the aging management program evaluation report, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.7 B.1.22 Flow-Accelerated Corrosion (XI.M17)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material in carbon steel lines and components that contain high energy fluids. The program implemented the guidelines in Electric Power Research Institute NSAC 202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," Revision 3. The applicant planned to enhance their existing program to closely monitor the downstream sections of piping. The Flow-Accelerated Corrosion program manages loss of material resulting from wall thinning for piping and components by conducting appropriate analysis and baseline inspections, determining the extent and rate of wall thinning, performing follow-up inspections, and taking corrective actions as necessary.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, corrective action program documents, plant operating experience, and flow-accelerated corrosion evaluations. In addition, the team searched the corrective action program database for relevant corrective action requests. The team interviewed the program owner and license renewal project personnel. The team reviewed the program owner's database for a selected sample of monitoring points.

The team evaluated whether the applicant monitored other systems for loss of material resulting from mechanisms other than flow accelerated corrosion using the Flow-Accelerated Corrosion program. Specifically, the team evaluated the basis for the applicant monitoring locations in the low pressure core spray and high pressure core spray systems since these systems did not normally have conditions conducive to flow-accelerated corrosion. The team determined that the aging management program evaluation report for the Flow-Accelerated Corrosion program did not discuss the monitoring of non-susceptible systems and did not discuss monitoring for loss of material resulting from mechanisms other than flow-accelerated corrosion. The team determined that the applicant began monitoring the low pressure core spray, high pressure core spray, and residual heat removal (RHR) systems as a corrective action for a pinhole leak that occurred in the residual heat removal system in 2001.

After consulting with headquarters, the team determined that the aging management review tables in the License Renewal Application for these systems (high pressure core spray, low pressure core spray, residual heat removal) did not identify loss of material attributed to flow-accelerated corrosion as an aging effect requiring monitoring. The applicant initiated Condition Report CR 2012-10082 to document that the License Renewal Application did not include use of the Flow-Accelerated Corrosion program to monitor for aging effects in the aging management review tables for the low pressure core spray, high pressure core spray and the residual heat removal systems.

The applicant committed to revise the Flow-Accelerated Corrosion program prior to entering the period of extended operation. Specifically, the applicant planned to enhance the program to closely monitor downstream components to mitigate any increased wear when susceptible upstream components are replaced with resistant materials, such as high chromium content material.

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 and the corrective actions taken related to the License

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

.8 B.1.27 Masonry Wall (XI.S5)

The Masonry Wall program was an existing program consistent with the GALL Report after enhancement. The program was implemented as part of the Structures Monitoring program and was credited with managing cracking of masonry walls through visual inspections. Structural steel components of masonry walls will be managed by the Structures Monitoring program. The team confirmed that the applicant had masonry walls in the containment building, standby service water cooling towers and basins, turbine building, auxiliary building, control building, radioactive waste building, and fire water pumphouse.

The team reviewed license renewal documents, the aging management program evaluation report, program procedures, corrective action documents, and masonry wall drawings. The team also conducted an independent search of the applicant's corrective action program, and reviewed a sample of the corrective action reports returned. The team discussed the program with civil engineers and visually examined accessible masonry block walls to assess their condition. The applicant specified they would continue to use the guidance in Maintenance Rule Structures Monitoring Program to perform the visual inspections. The team verified that the applicant did have safety-related masonry block walls.

This program required two enhancements to be consistent with the GALL Report. Specifically, the applicant planned to clarify that parameters monitored or inspected will include monitoring gaps between the supports and masonry walls that could potentially affect wall qualification, and that masonry walls would be inspected every five years.

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 address aging effects during the period of extended operation.

.9 B.1.29 Non-EQ Inaccessible Power Cables (400V to 35kV) (XI.E3)

This was an existing aging management program, consistent with the GALL Report, credited with managing aging related to normally energized inaccessible low and medium voltage cables that could be exposed to significant moisture. The applicant planned to manage 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 in-scope inaccessible low and medium-voltage electrical cables prior to the period of extended operation and at least once every 6 years thereafter. 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 prior to entering the period of extended operation and continuing annually thereafter.

The team reviewed license renewal documents, the aging management program evaluation report, the program implementing procedure, industry operating experience, work orders and preventative maintenance documents. The team observed an in-scope manhole inspection.

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 cable testing every 6 years. Whenever plant personnel found water in manholes, they would measure the amount of water prior to pumping the water from the manhole, and generate a condition report to document the water found and actions taken to remove the water from the manhole. Corrective actions and engineering evaluations will be performed when a test or inspection acceptance criteria are not met.

The applicant had experienced no failures of low or medium-voltage cables because of water treeing or submergence. 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.

.10 B.1.32 Oil Analysis (XI.M39)

This was an existing program, consistent with the GALL Report after enhancement, for maintaining lubricating and hydraulic oil systems free of contaminants (primarily water and particulates), thereby preserving an environment that was not conducive to loss of material, cracking, or fouling. The program enhancements were to include the oil components of the main generator system within the program and to provide a formalized analysis technique for particulate counting. The applicant performs sampling, analysis, and trending of results on numerous systems as listed in their aging management program to provide an early indication of adverse equipment condition in the oil environments.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, program and implementing procedures, and relevant condition reports. The team interviewed license renewal and plant personnel, and performed walk downs of the accessible lubricating oil components of Division I and Division III emergency diesel generators, and diesel-driven fire pumps. The team sampled oil measurement results and trending within the applicant's database.

The team determined that the existing Oil Analysis program was managing the aging of oil components, based on the team's review of completed oil sample analyses, sample results reviews and lubrication oil related corrective actions; however, the team noted that site administrative procedures did not contribute to this performance. The three administrative procedures were inconsistent and out-of-date for the existing practices for electronically-based sample analysis and review, and lubrication engineer responsibilities. The applicant noted that benchmarking and procedure changes were planned.

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 piping and component surfaces in lubricating and hydraulic oil systems. The team concluded that, if implemented as described including enhancements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.11 B.1.35 Periodic Surveillance and Preventive Maintenance (Plant-Specific)

This was an existing, plant-specific program credited with managing aging effects not managed by other aging management programs, including loss of material, cracking, and changes in material properties. The applicant credited specific preventive maintenance and surveillance program activities for the following systems and structures:

- Gasket/seal for upper containment pool gates in the containment building.

- High pressure core spray system, low pressure core spray system, pressure relief system, reactor core isolation cooling system, and residual heat removal system piping passing through the waterline region of the suppression pool.

- Control rod drive system piping.

- Circulating water system piping and valve bodies.

- Floor and equipment drain system piping, drain housings, and valve bodies, including piping located below the waterline in the in-scope sumps.

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. The team interviewed the program owner and license renewal project personnel.

Because this was an existing program, the applicant will enhance the program and revise guidance documents, as necessary, to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation. The applicant committed to implement this enhancement prior to the period of extended operation. The team confirmed that the aging management program evaluation report specifically listed these items as requiring preventive maintenance activities to evaluate the condition of the piping and to review for aging effects.

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 address aging effects during the period of extended operation.

.12 B.1.36 Protective Coating Monitoring and Maintenance (XI.S8)

This was an existing program, consistent with the GALL Report after enhancement, credited with monitoring and maintaining Service Level I coatings inside containment. The program included coatings that covered steel and concrete surfaces inside containment (e.g., steel liner, steel shell, supports, concrete surfaces, and penetrations).

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

The Protective Coating Monitoring and Maintenance program will be enhanced to revise program documents prior to entering the period of extended operation to: (1) include parameters monitored or inspected per the guidance provided in American Society for Testing and Materials D5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants"; (2) provide for inspection of coatings near sumps or screens associated with the emergency core cooling system; and (3) include acceptance criteria specified in American Society for Testing and Materials D5163-08.

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 address aging effects during the period of extended operation.

.13 B.1.39 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program was an existing program consistent with the program described in the GALL Report after enhancement. The program was implemented as part of the Structures Monitoring program and was credited with managing loss of material, cracking, change in material properties, and loss of form of water-control structures through visual inspections. The existing program was developed based on guidance provided in Nuclear Regulatory Commission Regulatory Guide 1.127, Revision 1, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." Water-control structures within the scope of the program included the two standby service water cooling tower and basin structures and the Culvert No. 1 and drainage channel used for flood control.

The team reviewed license renewal documents, the aging management program evaluation report, program procedures, corrective action documents, and engineering requests. The team interviewed the program engineers and discussed the results of the most recent inspection, existing program procedures, and qualifications of inspection personnel. The team performed walkdowns with civil engineers involved with performing the inspections and visually examined a sample of structures and structural components including the standby service water pump house, standby service water pipe and valve room, and the Culvert No. 1 and drainage channel.

This program required three enhancements to be consistent with the GALL Report. Specifically, the applicant planned to clarify that detection of aging effects will monitor accessible structures on a frequency not to exceed 5 years. The applicant will enhance the program to perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years. Further, the applicant planned to enhance the acceptance criteria to include quantitative acceptance criteria for evaluation and acceptance based on the guidance provided in American Concrete Institute standard 349.3R.

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 address aging effects during the period of extended operation.

.14 B.1.41 Service Water Integrity (XI.M20)

The Service Water Integrity program was an existing program that will be compared to the program described in the GALL Report, Section XI.M20, “Open-Cycle Cooling Water System.” The program was credited with managing the loss of material and fouling in open-cycle cooling water systems as described in the Grand Gulf Nuclear Station response to NRC Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The applicant will continue to manage aging effects through inspection and surveillance tests combined with chemistry controls, flushing and cleaning to minimize fouling, loss of material, and cracking. The in-scope systems included the standby service water and plant service water systems, and components connected to or serviced by these systems.

Commitment change evaluation CCE-2006-002 was submitted by the applicant to allow an alternative to the testing methods described in NRC Generic Letter 89-13 for the residual heat removal heat exchangers. The change was requested due to the difficulty in testing the residual heat removal heat exchangers with sufficient heat load to achieve statistically significant results. The residual heat removal heat exchangers are mechanically cleaned and inspected on six year intervals in lieu of thermal performance testing as described in the original response to Generic Letter 89-13. The team reviewed this change and considered the impact on aging management of the heat exchanger intended function. The team determined the different method of ensuring the heat exchangers would remain capable of performing their intended function was appropriate.

The standby service water system performs the ultimate heat sink function and consists of two cooling towers, each with a water cooling tower basin. These two cooling tower basins were interconnected by a siphon line. The team determined that the applicant had replaced the siphon line with a new line manufactured from an austenitic stainless steel alloy having high nickel, molybdenum and nitrogen content making it highly resistive to chloride corrosion, pitting, crevice corrosion, and stress corrosion cracking. The team concluded the change had improved the siphon line resistance to aging effects. The plant service water system included, in part, the piping and components in the system that maintained the pressure boundary for the fill line going to the standby service water fill tank, the lines to the standby service water system, and the component cooling water heat exchangers. For license renewal, the primary intended function of the plant service water system components was to maintain system pressure boundary integrity.

The team determined that the applicant had upgraded the spent fuel pool cooling heat exchangers with two plate and frame style heat exchangers to remove the additional heat load created by the recent extended power uprate. The team reviewed the technical data sheets and specifications for the new heat exchangers and concluded the aging effects were appropriately addressed.

The team reviewed the aging management program evaluation report, implementing procedures, corrective action documents, work orders and industry guidance. The team reviewed applicant commitment changes to the original NRC Generic Letter 89-13 response, self-assessments, standby service water system flow test data, and heat exchanger test results. The team performed walkdowns of accessible portions of the standby service water cooling towers and basins, standby service water piping and components, emergency diesel generator jacket water and lubricating oil heat exchangers, component cooling water heat exchangers and plant service water piping. The team interviewed the standby service water system program owner and heat exchanger engineers. Diver inspections of the standby service water basin were in progress while the team was onsite and the team reviewed a preliminary report of the material condition of the submerged components and structures.

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 systems. 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.

.15 B.1.42 Structures Monitoring (XI.S6)

The Structures Monitoring program was an existing program consistent with the GALL Report after enhancement. The program was credited with managing loss of material, cracking, and change in material properties of structures and structural components, including structural bolting, through visual inspections. The existing program was implemented as part of the Maintenance Rule and inspections are conducted using guidelines provided in the American Concrete Institute Standards 201.1R and 349.3R.

This program required numerous enhancements to be consistent with the GALL Report. Specifically, the applicant planned to expand the scope of their existing program to add in-scope structures, structural components, and commodities not specifically identified in the current program procedures. The applicant planned to enhance the program to include guidance to perform periodic sampling, testing, and analysis of ground water chemistry. The applicant identified an enhancement for the parameters monitored or inspected to include the inspection for missing nuts on structural connections, and monitoring of elastomeric vibration isolators and structural sealants for cracking, loss of material, and hardening. The applicant identified an enhancement for vibration isolators to include augmented tactile inspections to detect hardening. Further, in the Response to Request for Additional Information dated May 3, 2012, the licensee revised the program to include an enhancement to include periodically inspecting the leak chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tale drains are free of significant blockage.

The team reviewed license renewal documents, the aging management program evaluation report, program procedures, corrective action documents, work orders, and engineering requests. The team interviewed the program engineers and discussed program enhancements, existing program procedures, and qualifications of inspection personnel. The team performed walkdowns with civil engineers involved with performing the inspections and visually examined a sample of structures and structural components in the control building and auxiliary building. The team also performed independent walkdowns in the auxiliary building and inside containment.

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 address aging effects during the period of extended operation.

.16 B.1.43 Water Chemistry Controls – BWR (XI.M2)

The Water Chemistry Controls – BWR program was an existing program, consistent with the program described in the GALL Report, credited with managing loss of material, cracking, and fouling in components exposed to a treated water environment by maintaining the concentration of contaminants below system specific limits based on Electric Power Research Institute guideline, BWRVIP-190, "BWR Water Chemistry Guidelines," 2008 Revision. The applicant planned to supplement this program with the One-Time Inspection program which utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR program has been effective at managing aging effects.

The team reviewed license renewal documents, the aging management program evaluation report, program procedures, corrective action documents, the site strategic chemistry plan, and chemistry trend data for reactor water, final feedwater, and control rod drive cooling water. The team interviewed the site chemistry manager and discussed relevant corrective action documents, as well as recent changes to the site's method for controlling hydrogen water chemistry. The applicant controlled hydrogen water chemistry using Moderate Hydrogen Water Chemistry until 2010 when the plant began noble metal chemical application with hydrogen injection, accomplished through Online Noble Metal Chemical Addition. The team verified that the applicant's program monitors concentrations of corrosive impurities and maintains water quality in accordance with the Electric Power Research Institute, BWRVIP-190, "BWR Water Chemistry Guidelines," 2008 Revision.

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 address aging effects during the period of extended operation.

.17 B.1.44 Water Chemistry Control – Closed Treated Water System (XI.M21A)

The Water Chemistry Control – Closed Treated Water System program was an existing program consistent with the program described in the GALL Report after enhancement. The program was credited with managing loss of material, cracking, and fouling in components exposed to a treated water environment through monitoring and control of water chemistry as well as visual inspections.

This program required enhancements to be consistent with the GALL Report. Specifically, the applicant planned to provide a corrosion inhibitor for the engine jacket water on the engine-driven fire water pump diesels, test the engine jacket water for the engine-driven fire water pump diesels at least annually, and periodically flush the engine jacket water and clean the heat exchanger tubes for the engine-driven fire water pump diesels. Further, in the Response to Request for Additional Information dated April 26, 2012, the licensee revised the program to include an enhancement to align the water chemistry control parameter limits for closed treated water systems with those of Electric Power Research Institute Report 1007820, "Closed Cooling Water Chemistry Guideline Revision 1 to TR-107396."

The team reviewed license renewal documents, the aging management program evaluation report, program procedures, corrective action documents, the site closed cooling water strategic plan, and chemistry trend data for component cooling water, turbine building cooling water, and diesel generator jacket cooling water. The team discussed the program with the site chemistry specialist for cooling water systems, including recent challenges and corrective actions relevant to the program. The team verified that the applicant's program provided chemical treatment for closed treated water systems, including corrosion inhibitors. The team noted that the component cooling water and turbine building cooling water were treated with molybdate and tolytriazole corrosion inhibitors, while the diesel generator jacket cooling water was treated with molybdate, tolytriazole, and nitrite corrosion inhibitors.

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 address aging effects during 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:

- Standby service water
- Reactor core isolation cooling

The team interviewed the license renewal staff members and the system engineers responsible for the reactor core isolation cooling system and the standby service water system. 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 aging effects requiring management for the standby service water system included loss of material, loss of pre-load, 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, Oil Analysis Program, and the Service Water Integrity Program. 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 pre-load and reduction of heat transfer. The applicant credited the following aging management programs for managing the identified aging effects: Bolting Integrity Program, External Surfaces Monitoring Program, Flow-Accelerated Corrosion Program, Oil Analysis Program, Periodic Surveillance and Preventive Maintenance Program and the Water Chemistry Control – BWR Program. 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. 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 <u>Meetings, Including Exit</u>

The team presented the inspection results to Mr. J. Browning, General Manager Plant Operations, and other members of the applicant's staff during an exit meeting conducted on August 23, 2012. 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

A. Fox	System Engineer – External Surfaces Monitoring
A. Hughes	System Engineer – Standby Service Water
A. Patel	System Engineer – 115-kV Transmission Cables
B. Taylor	Program Owner – Buried Piping and Tanks
B. Townley	Program Owner – Selective Leaching
C. Loyd	Program Owner – Diesel Fuel Oil
C. Nash	Program Owner –Water Chemistry
E. Burton	System Engineer – A2 Scoping and Screening
E. Rufus	Supervisor – Code Programs
F. Hopkins	Civil Engineer Design
G. Young	Director – Business Development
J. Browning	General Manager – Plant Operations
J. McAdory	Program Owner – Oil Analysis
J. Seiter	Senior Licensing Specialist
L. Henderson	Program Owner - Flow Accelerated Corrosion
L. Patterson	Manager – Programs and Components – Engineering
M. Humphries	Program Owner – Non EQ Cables
M. Locke	Senior Civil Engineer Design
M. Richey	Director - Nuclear Safety Assurance
P. Griffith	System Engineer – Standby Service Water
R. Green	System Engineer – Non EQ Cables
R. Sorrels	Fire Protection Engineer
R. Summers	System Engineer – Diesel Fuel Oil
S. Carlisle	Program Owner – 115-kV Transmission Cables
S. Lee	System Engineer – Chemistry
T. Bryant	Program Owner – Environmental Qualification
T. Robinson	Civil Engineer Design
V. Kirk	Program Owner – Standby Service Water
W. Dinkard	System Engineer – External Surfaces Monitoring

Entergy License Renewal Staff

A. Cox	License Renewal Technical Manager
A. Taylor	License Renewal – Mechanical Lead
B. Nichols	License Renewal Engineer – Mechanical
D. Wooten	License Renewal Engineer – Mechanical
J. Robinson	License Renewal Engineer – Electrical
L. Loyd	License Renewal Engineer – Mechanical
L. Seamans	License Renewal Engineer – Mechanical
R. Ahrabli	License Renewal Engineer – Civil Lead
R. Rucker	License Renewal – Electrical Lead
S. Clair	License Renewal Engineer
T. Ivy	License Renewal - Manager
W. Bichlmeir	License Renewal Engineer – Mechanical

TABLES OF DOCUMENTS REVIEWED

GENERAL

Drawings:

NUMBER	TITLE	REVISION
C-0012	Site and Yard Work Plot Plan	25
M-0030A	P & I Diagram Legend Units 1 and 2	28

Fleet Administrative Procedures:

NUMBER	TITLE	REVISION
EN-FAP-LR-001	License Renewal Overview and Project Plan	2
EN-FAP-LR-003	System and Structure Scoping for License Renewal	1

License Renewal:

NUMBER	TITLE	REVISION/DATE
	Grand Gulf Nuclear Station License Renewal Application	October 28, 2011
NUREG-1801	Generic Aging Lessons Learned (GALL)	2

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
EN-DC-178	System Walkdowns	4
EN-LI-121	Entergy Trending Process	12
EN-LI-121-1	Entergy Trending Codes	2
EN-LI-102	Corrective Action Program	17
EN-OE-100	Operating Experience Program	14
QA-8-2005-ENS	Quality Assurance Multi-Site Audit of Engineering Programs	August 4, 2005
	NRR AMP Audit Report	

Operating Experience:

NUMBER	TITLE	DATE
LR-ISG-2011-05	Ongoing Review of Operating Experience	March 16, 2012

Project Documents:

NUMBER	TITLE	DATE
GGNS-EP-08-LRD01	System and Structure Scoping Results	July 18, 2011
GGNS-EP-08-LRD02	Operating Experience Review Report - AERM	September 16, 2011

NUMBER	TITLE	DATE
GGNS-EP-08-LRD03	TLAA and Exemption Evaluation Results	August 3, 2011
GGNS-EP-08-LRD05	Aging Management Program Evaluation Report Class 1 Mechanical	October 26, 2011
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report Non-Class 1 Mechanical	October 26, 2011
GGNS-EP-08-LRD07	Aging Management Program Evaluation Report Civil/Structural	August 11, 2011
GGNS-EP-08-LRD08	Aging Management Program Evaluation Results Electrical	October 11, 2011
GGNS-EP-08-LRD09	Aging Management Review Summary	October 25, 2011
GGNS-EP-08-LRD10	Operating Experience Review Results –Aging Management Program Effectiveness	September 13, 2011
GGNS-ME-08-AMM20	Aging Management Review of Nonsafety-related Systems Affecting Safety-related Systems	September 16, 2011

SCOPING

Condition Reports (CR-GGN-):
2012-10047

Drawings:

NUMBER	TITLE	REVISION
	Complete set of license renewal drawings	0
FSK-H-1067B-280-G	Instrument Air Header & Conn for Diesel Generator Bldg	3
FSK-H-1083B-027-B	Gland Seal Supply to RCIC Turbine	3
HL-1325B	System Piping Isometric – Diesel Generator A, Starting Air	7
HL-1340C	System Piping Isometric –Service Air-Auxiliary Building	15
HL-1353P	System Piping Isometric –Freon Safety Relief Line, Plant Chilled Water	A

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD01	System and Structure Scoping Results	0

NEW PROGRAMS

B.1.1 115 kV Inaccessible Transmission Cable (Plant-Specific)

Drawings (LRA-):

NUMBER	TITLE	REVISION
E-001 Sheet 01	Offsite Power Recovery Diagram	0

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-LRD08	115 kV Inaccessible Transmission Cable Program	1

B.1.2 Aboveground Metallic Tanks (XI.M29)

Condition Reports (CR-GGN-):

2001-00098	2008-02080	2012-09773
2002-02404	2009-01916	2012-10081
2007-01032	2012-04617	

Drawings:

NUMBER	TITLE	REVISION
A-0720	Units 1 & 2 Roof Details	12
C-0325A	Fire Water Pump House & Storage Tanks – Reinf Conc Plan, Elevation, Sect & Details	9
C-0326A	Fire Water Pump House Structural Steel Plan, Elevations, Sects, & Details	5

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Miscellaneous:

NUMBER	TITLE	REVISION
9645-C-141.0	Technical Specification for Condensate Storage Tanks	0
9645-C-145.0	Technical Specification for Fire Water Storage Tank	7

Procedures:

NUMBER	TITLE	REVISION
07-S-14-2	Inspection of Tanks and Vessels	7
07-S-24-P64-A001-1	Inspection of Firewater Storage Tanks	5

Work Orders:

NUMBER	TITLE	DATE
00069971	Internal Inspection of Condensate Storage Tank	October 3, 2007
00102247	Repair Various Coating Deficiencies at 'A' FWST	May 6, 2008
00142846	Contingency to Weld Repair and Apply Coating (FWST-A)	May 16, 2008
00190618	Correct Coating Deficiencies Noted in CR 2009-1916	April 14, 2009
00190619	Correct Coating Deficiencies Noted in CR 2009-1916	April 14, 2009
00196395	Reseal the bottom of the CST to the floor slab	October 22, 1997
50306770	Internal Inspection of Fire Water Storage Tank A	November 11, 2002
50837816	Internal Inspection of Fire Water Storage Tank A	December 19, 1995
51206393	Inspection of Fire Water Storage Tank A	May 2, 2003
51689554	External Inspection of Fire Water Storage Tanks A/B	July 24, 2009
52213504	External Inspection of Fire Water Storage Tanks A/B	June 21, 2010
52303654	External Inspection of Fire Water Storage Tanks A/B	August 2, 2011

B.1.5 Buried Piping and Tanks Inspection (XI.M41)

Condition Reports (CR-GGN-):

2010-01376 2011-03524

License Renewal:

NUMBER	TITLE	DATE
LR-ISG-2011-03	Final License Renewal Interim Staff Guidance Changes To The Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, "Buried And Underground Piping And Tanks"	August 2, 2012

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
	Entergy Radiological SSC Risk Ranking Plant Risk Index [PRI]: Piping	July 06, 2010
0900596.401	Grand Gulf Nuclear Power Station APEC Survey	September 11, 2009

NUMBER	TITLE	REVISION/DATE
0900596-3	Grand Gulf Nuclear Power Station CP System Design, Installation and Energization	April 14, 2010
9645-C-033.1	Technical Specification for Backfill for Category I Structures for Mississippi Power and Light Company	7
CEP-UPT-0100	Underground Piping and Tanks Inspection and Monitoring	0
D448-98	ASTM Standard Classification for Sizes of Aggregate for Road and Bridge Construction	
EN-DC-343	Underground Piping and Tanks Inspection and Monitoring Program	5
NEI 09-14	Guideline for the Management of Underground Piping and Tank Integrity	1
Q2-2012	System Health Report – Cathodic Protection	
RP0285-2002	Standard Recommended Practice Corrosion Control of Underground Storage Tank Systems by Cathodic Protection	April 6, 2002
SERI-M-404.0	Specification for External Surface Treatment of Underground Metallic Pipe for Nuclear and Non-Nuclear Service	January 16, 1989
SP0169-2007	Standard Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems	March 15, 2007

Project Documents:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD10 Section 3.2.2	Operating Experience Review Results–Aging Management Program Effectiveness, Buried Piping and Tanks Inspection Program	0

B.1.28 Non-EQ Cable Connections (XI.E6)

Drawings:

NUMBER	TITLE	REVISION
E-0664	Manhole and Trench Typical Details	22

Work Orders:

NUMBER	TITLE	REVISION/DATE
52424502	SP45MH02 Perform Inspection of Manhole Water Level	

B.1.31 Non-EQ Insulated Cables and Connections (XI.E1)

Condition Reports (CR-GGN-):
2005-03807

Drawings:

NUMBER	TITLE	REVISION
LRA-E-001 Sheet 01	Offsite Power Recovery Diagram	0

Procedures:

NUMBER	TITLE	REVISION
EN-DC-348	Non-EQ Insulated Cables and Connections Inspection	3

B.1.33 One-Time Inspection (XI.M32)

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 3.4	One-Time Inspection	1

Miscellaneous:

NUMBER	TITLE	REVISION
EN-FAP-LR-024	One-Time Inspection	1

Operating Experience:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD10 Section 3.2.8	One-Time Inspection	0

B.1.40 Selective Leaching (XI.M33)

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 3.5	Selective Leaching	1

Miscellaneous:

NUMBER	TITLE	REVISION
EN-FAP-LR-025	Selective Leaching Inspection	3

Operating Experience:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD10 Section 3.2.10	Selective Leaching	0

EXISTING PROGRAMS

<u>B.1.13 Containment In-service Inspection – IWE (XI.S1)</u>

Condition Reports (CR-GGN-):

2001-00120	2003-02290	2007-01700

Drawings (LRA-):

NUMBER	TITLE	REVISION
C-1011	Containment – Cylinder Wall Liner Plate Sections & Details	6

Letters:

NUMBER	TITLE	DATE
GNRO-2009/00004	Inservice Inspection Summary Report	January 19, 2009
GNRO-2010/00061	Inservice Inspection Summary Report	August 23, 2010
GNRO-2012/00055	Response to Request for Additional Information (RAI) Set 12, dated May 9, 2012	June 6, 2012
	Requests for Additional Information for the Review of the Grand Gulf Nuclear Station License Renewal Application	July 27, 2012

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD07 Section 3.2	Aging Management Program Evaluation Report Civil/Structural, Containment Inservice Inspection – IWE	0

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
EPRI NP-5769	Degradation and Failure of Bolting in Nuclear Power Plants, Volumes 1 and 2	June 1998
EPRI TR-104213	Bolted Joint Maintenance and Applications Guide	December 1995
NUREG-1339	Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants	June 1990
SEP-CISI-102	Program Section for ASME Section XI, Division 1 GGNS Containment Inservice Inspection Program	0

NUMBER	TITLE	REVISION/DATE
Subsection IWA	Division 1 Rules for Inspection and Testing of Components of Light-Water Cooled Plants	2001
Subsection IWE	Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants	2001
Subsection IWL	Requirements for Class CC Concrete Components of Light-Water Cooled Plants	1998

Procedures:

NUMBER	TITLE	REVISION
07-S-09-20	Bolt Torquing	1
07-S-14-297	Torquing Requirements for General Maintenance Tasks	8
CEP-CII-003	General Visual Examination of Class MC Components	303
CEP-CII-004	General and Detailed Visual Examinations of Concrete Containments	304
CEP-NDE-0901	VT-1 Visual Examination	4
CEP-NDE-0903	VT-3 Visual Examination	5
EN-DC-141	Design Inputs	10

Work Orders:

NUMBER	TITLE	DATE
00178617 -01	Perform IWE Examinations of Containment Liner and Components During RF17	May 7, 2010

B.1.15 Containment Leak Rate Test (XI.S4)

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD07 Section 3.1	Aging Management Program Evaluation Report, Containment Leak Rate Program	0

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
	Containment System Health Report	
	Results from previous two integrated leak rate tests	

NUMBER	TITLE	REVISION/DATE
	Refueling Outage 18 local leak rate test results and failures	
ANSI 56.8	Containment System Leakage Testing Requirements	2002
Engineering Change 33448	Change the Specified Position of Valves 1G36F101 and 1G36F106 from Normally Closed To Normally Open	0
GNRI-2004-00013	Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment RE: One-Time Extension of the Integrated Leak Rate Test and Drywell Bypass Test Interval	January 28, 2004
NEI 94-01	Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J	2A

Procedures:

NUMBER	TITLE	REVISION
17-S-05-1	Guideline for Local Leak Rate Test Program for the Appendix J Program	109
CEP-NDE-0901	VT-1 Visual Examination	4
CEP-NDE-0903	VT-3 Visual Examination	5
CEP-PT-001	ASME Section XI Pressure Testing Program	305
EN-DC-334	Primary Containment Leakage Rate Testing (Appendix J)	1
SEP-APJ-003	Primary Containment Leakage Rate Testing Program	1

B.1.16 Diesel Fuel Monitoring (XI.M30)

Condition Reports (CR-GGN-):

2005-05264	2008-00283	2010-04687

Drawings (LRA-):

NUMBER	TITLE	REVISION
L-3197	Diesel Generator Fuel Oil Storage Tanks	4
M-1413	Yard Piping – Sections and Details	18

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.4	Diesel Fuel Monitoring	1

Operating Experience:

NUMBER	TITLE	REVISION/DATE
GGNS-EP-08-LRD10 Section 3.1.11	Diesel Fuel Monitoring Program	0
	Condition Report database search of diesel fire pump oil tanks	January 2008-August 2012

Procedures:

NUMBER	TITLE	REVISION
06-CH-1P75-Q-0055	Div I Diesel Generator Fuel Oil Tank A003A – Viscosity, Insolubles, Water, and Sediment	108
06-CH-SP64-Q-0039	Fire Water Diesel Fuel Oil Viscosity, Water, and Sediment	104
06-ME-1P75-0-0002	Diesel Generator Fuel Oil Storage Tank Cleaning and Inspection	106
06-OP-SP64-M-001	Fire Pump Monthly Operability Test, completed on A & B on July 17, 2012	109

Work Orders:

NUMBER	TITLE	DATE
56463-01	Fire diesel fuel oil tank A drained	October 27, 2005
56464-01	Fire diesel fuel oil tank B drained	July 27, 2005
560003-01	Div I fuel oil tank cleaned	February 1, 2005
	Chemistry results for A & B fire diesel fuel oil tanks	January 4, 2011 April 5, 2011 June 24, 2011 October 3, 2011
MAI 327093	Div III fuel oil tank cleaned	March 1, 2003

<u>B.1.18 External Surfaces Monitoring (XI.M36)</u>

Condition Reports (CR-GGN-):

2010-05494 2012-10051

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.5	External Surfaces Monitoring	1

Procedures:

NUMBER	TITLE	REVISION
EN-DC-178	System Walkdowns	3
EN-LI-102	Corrective Action Process	17
EN-TQ-104	Engineering Support Personnel Training Program	10
17-S-01-6	Engineering Personnel Qualification and Certification	7

B.1.20 Fire Protection (XI.M26)

Condition Reports (CR-GGN-):

2006-01908	2007-05501	2010-05678	2012-04360	2012-07890
2007-03323	2009-03276	2010-06120	2012-05594	2012-08624
2007-04025	2010-05541	2012-02968	2012-06556	2012-08400

Drawings :

NUMBER	TITLE	REVISION
Figure 1-1	Typical Steel Housed Storage Unit (CO_2 Storage Tank	
Figure 1-2	Cutaway View of Cardox Steel Housed Storage Unit	
Figure 1-3	Cutaway View of Model D46490 Storage Tank	
LRA-M-0035E	P & I Diagram Fire Protection System Unit 1	22
LRA-M-0035F	P & I Diagram Fire Protection System Units 1 & 2	20

License Renewal:

NUMBER	TITLE	REVISION
GGNS-ME-08-AMM16	Aging Management Review of the Fire Protection: CO_2 – Halon System	0
GGNS-EP-08-LRD06 Section 4.6	Aging Management Program Evaluation Report, Fire Protection	1

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
1Q-2010	GGNS Fire Protection Program – Health Report	
2Q-2009	GGNS Fire Protection Program – Health Report	

NUMBER	TITLE	REVISION/DATE
3Q-2009	GGNS Fire Protection Program – Health Report	
LO-GLO-2004-00122	2004 Fire Protection Assessment T-4	August 19, 2004
LO-GLO-2006-00067	2006-ES-T2 Fire Protection Corporate Asmt	June 6, 2006
LO-GLO-2010-0089	GGNS Fire Protection Focused Self-Assessment	October 15, 2010
Q1-2012	System Health Report	
Q2-2012	System Health Report	
QA-9-2008-GGNS-1	Fire Protection Program Audit	April 24, 2008

Procedures:

NUMBER	TITLE	REVISION
06-ME-SP64-R-0045	Surveillance Procedure Ventilation System Fire Dampers Inspection Safety Related	107
06-ME-SP64-R-1001	Surveillance Procedure PGCC Halon System Flow Test Safety Related	105
06-OP-SP64-D-0002	Surveillance Procedure 10 Ton CO_2 Systems Puff Test Safety Related	106
06-OP-SP64-D-0044	Surveillance Procedure Fire Door Check Safety Related	115
06-OP-SP64-R-0047	Surveillance Procedure Fire Rated Assembly Visual Inspection Safety Related	113
06-OP-SP64-R-0048	Surveillance Procedure Visual Inspection of Fire Wrapped Raceways Safety Related	107
06-OP-SP64-R-0049	Surveillance Procedure Fire rated Sealed Penetrations Visual Inspection Safety Related	108
15-S-02-106	Plant Modification Section Procedure Penetration Closures Safety Related	008
M-227.3	Grand Gulf Nuclear Station Penetration Closure Materials Safety-Related	2

Project Documents:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.6	Aging Management Program Evaluation Report–Fire Protection	1
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report–External	1

NUMBER	TITLE	REVISION
Section 4.5	Surfaces Monitoring	
GGNS-EP-08-LRD10 Section 3.1.13	Operating Experience Review Results–Aging Management Program Effectiveness, External Surfaces Monitoring	0
GGNS-EP-08-LRD10 Section 3.1.15	Operating Experience Review Results–Aging Management Program Effectiveness, Fire Protection Program	0

B.1.21 Fire Water System (XI.M27)

Drawings (LRA-):

NUMBER	TITLE	REVISION
M-0035A	Fire Protection System	28
M-0035B	Fire Protection System	47
M-0035E	Fire Protection System	22
M-0035F	Fire Protection System	20
M-0035G	Fire Protection System	12
M-0035H	Fire Protection System	22
M-0035K	Fire Protection System	13
M-0035L	Fire Protection System	17
M-0035R	Fire Protection System	1

Letters:

NUMBER	TITLE	DATE
GNRO-2012/00042	Response to Request for Additional Information (RAI)	May 15, 2012
GNRO-2012/00089	Response to Request for Additional Information (RAI) Set 27	August 13, 2012

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.7	Aging Management Program Evaluation Report, Non-Class 1 Mechanical, Fire Water System	1

Miscellaneous:

NUMBER	TITLE	REVISION
	Reviewed database search of hose, flow, blockage	
1Q-2012	System Health Report	
Calculation MC NIP64-86056	Pressure Drop Across Seven Fire Suppression Water System Loops Tested By Surveillance Procedure 06-OP-SP64-0010	0
NFPA 25-1998	Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems	
NFPA 25-2002	Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems	

Procedures:

NUMBER	TITLE	REVISION
04-S-01-P64-1	Fire Protection Water System	61
06-ME-SP64-A-0017	Yard Fire Hose Hydrostatic Check	103
06-OP-SP64-M-0011	Fire Protection System Valve Lineup Verification	112
06-OP-SP64-M-0047	Unit 1 Fire Hose Station And Fire Extinguisher Maintenance	115
06-OP-SP64-O-0010	Fire Suppression Water System Loop Flow Test	103
06-OP-SP64-R-0016	Unit 1 Fire Hose Check	107
06-OP-SP64-R-0019	Sprinkler Systems Functional Tests	106
06-OP-SP64-SA-0014	Yard Fire Hydrant Check	101

B.1.22 Flow Accelerated Corrosion (XI.M17)

Condition Reports (CR-GGN-):

2001-00955	2007-02316	2010-03334
2007-01566	2008-05080	2010-03608

Letters:

NUMBER	TITLE	DATE
AECM-87/0175	IE Bulletin 87-01: Thinning of Pipe Walls in Nuclear Power Plants	September 11, 1987
AECM-89/0116	Corrosion-Induced Pipe Wall Thinning	July 21, 1989
GNRO-2012/00033	Response to Request for Additional Information (RAI), dated April 25, 2012	May 25, 2012

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.8	Aging Management Program Evaluation Report, Non-Class 1 Mechanical, Flow-Accelerated Corrosion	1

Miscellaneous:

NUMBER	TITLE	REVISION
	List of flow accelerated corrosion condition reports	
	List of susceptible non-monitored items	
Calculation MC-Q1111-02013	Evaluation of RF12 Flow Accelerated Corrosion (FAC) Wall Thickness Data	0
Calculation MC-Q1111-08013	Evaluation of RF16 Flow Accelerated Corrosion (FAC) Wall Thickness Data	0
Engineering Change 2058	Replace the Existing Carbon Steel 4”-DBB-11 Piping of the HPCS System from Downstream of Orifice Q1E22-D001 to MOV Q1E22-F012 with Stainless Steel Material for FAC Item 659	0
Report 0700.104-10	FAC System Susceptibility Evaluation (SSE)	0

Procedures:

NUMBER	TITLE	REVISION
CEP-NDE-0505	Ultrasonic Thickness Examination	4
EN-DC-315	Flow-Accelerated Corrosion Program	4
ENN-EP-S-005	Flow Accelerated Corrosion Program Component Scanning and Gridding Standard	1

Work Orders:

NUMBER	TITLE	DATE
00166538	Replace 2-inch Line Downstream of N33D012 (AC 553)	October 10, 2008
00236402	Perform Weld Buildup on Elbow – 14-inch-HBD-912	May 19, 2010
52387367	Review of Quarterly Plant Operating Conditions	

B.1.27 Masonry Wall (XI.S5)

Condition Reports (CR-GGN-):

2003-01609	2010-03882	2012-01547
2003-02291	2012-00666	

Drawings (LRA-):

NUMBER	TITLE	REVISION
A-0879	Control Building Structural and Masonry Sections and Details	8
A-0880	Control Building Structural and Masonry Sections and Details	8

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Procedures:

NUMBER	TITLE	REVISION
EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2

B.1.29 Non-EQ Inaccessible Power Cables (≥ 400V to 35kV) Program (XI.E3)

Condition Reports (CR-GGN-):

2011-00498	2011-07856	2012-05620
2011-00562	2011-05250	
2011-01609	2012-03350	

Drawings:

NUMBER	TITLE	REVISION
E-0664	Manhole and Trench Typical Details Units 1 & 2	22

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EE-08-AME01	Aging Management Review of Electrical Systems	0
GGNS-EP-08-LRD08 Section 4.2	Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program	1

NUMBER	TITLE	REVISION
LRA Appendix B.1.29	Non-EQ Inaccessible Power Cables (400 V to 35 kV)	

Miscellaneous:

NUMBER	TITLE	REVISION
PM Basis Template	EN-Manhole Inspection and De-Watering	0
PM Basis Template	EN-Cable-Medium Voltage	0

Procedures:

NUMBER	TITLE	REVISION
EN-CY-108	Monitoring of Nonradioactive Systems	4
EN-DC-346	Cable Reliability Program	1
EN-DC-346	Cable Reliability Program	3

Work Orders:

NUMBER	TITLE	DATE
258623	152-1504: Perform Feeder Cable Testing During RF18	
52408456	SP45MH20 Perform Inspection of Manhole Water Level	8/2/2012
52424502	SP45MH02 Perform Inspection of Manhole Water Level	7/10/2012

<u>B.1.32 Oil Analysis (XI.M39)</u>

Condition Reports (CR-GGN-):

2005-05416	2009-04892	2010-00048

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.9	Oil Analysis	1

Miscellaneous:

NUMBER	TITLE	DATE
	Qualification Card – Level II Lubrication Engineer	July 10, 2011
	R&G Laboratories, Inc - Oilography Database for Grand Gulf	

Operating Experience:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD10 Section 3.1.21	Oil Analysis Program	0

Procedures:

NUMBER	TITLE	REVISION
01-S-07-27	Lubricating Oil Sample Program	13 and 14
01-S-17-21	Oil/Lubricant Program	8
08-S-04-368	Chemistry Instruction – Water and Sediment in Oil	1
EN-DC-310	Predictive Maintenance Program	4
M-518.0	Program for Lubrication Requirements	4

B.1.35 Periodic Surveillance and Preventive Maintenance (Plant-Specific)

Condition Reports (CR-GGN-):

2007-04940	2009-00545

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06 Section 4.10	Aging Management Program Evaluation Report, Non-Class 1 Mechanical, Periodic Surveillance and Preventive Maintenance	1

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
GNRO-2012/00032	Response to Request for Additional Information (RAI), dated April 11, 2012	May 9, 2012
Policy EN-PL-161	Zero Tolerance for Unanticipated Equipment Failures	0

Procedures:

NUMBER	TITLE	REVISION
Procedure EN-DC-324	Preventive Maintenance Program	6

B.1.36 Protective Coating Monitoring and Maintenance (XI.S8)

Letters:

NUMBER	TITLE	DATE
GNRO-98/00092	Response to Generic Letter (GL) 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment, dated July 14, 1998	November 11, 1998
GNRO-2012/00055	Response to Request for Additional Information (RAI) Set 12, dated May 9, 2012	June 6, 2012
	Requests for Additional Information for the Review of the Grand Gulf Nuclear Station License Renewal Application	July 27, 2012

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD07 Section 3.8	Aging Management Program Evaluation Report Civil/Structural, Protective Coating Monitoring and Maintenance Program	0

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
ASTM 1186-87	Standard Test Methods for Non-Destructive Measurement of Dry Film Thickness of Non-Magnetic Coatings Applied to a Ferrous Base	
ASTM D3359-93	Standard Test Methods for Measuring Adhesion by Tape Test	
ASTM D4541-93	Standard Test Method for Pull-off Strength of Coatings Using Portable Adhesion Testers	
ASTM D5163-08	Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants	
EPRI 1019157	Guideline on Nuclear Safety-Related Coatings	2
GIN 2000-00715	Service Level I Coating Condition Assessment	July 12, 2000
GIN 2010-00129	Service Level I Coating Condition Assessment Continuation	May 10, 2010
GIN 2012-00192	Service Level I Coating Condition Assessment Continuation	March 20, 2012

NUMBER	TITLE	REVISION/DATE
SSPC (Steel Structures Painting Council)-PA 2	Measurement of Dry Coating Thickness with Magnetic Gages	June 1, 1996
SSPC-VIS 2 (ASTM D610-01)	Standard Test Method for Evaluating Degree of Rusting on Painted Steel Surfaces	

Procedures:

NUMBER	TITLE	REVISION
07-S-07-211	Service Level I Coatings Condition Assessment	2
EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2

<u>B.1.39 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)</u>

Condition Reports (CR-GGN-):

1997-0194	1999-1804	2007-00424
1999-1393	2004-04533	2011-02064

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Procedures:

NUMBER	TITLE	REVISION
06-TE-1000-V-0001	Culvert No. 1 Embankment Stability Inspection/Survey	100

Engineering Requests (ER-):

NUMBER	TITLE	DATE
1997-0330-00	Repair of SSW Basin Roof Slabs	March 19, 1999
1997-0330-01	Additional Nonconformance at SSW Basins	October 14, 1997
1997-0330-02	Inspection and Testing of SSW Basins A & B	August 6, 1998
1997-0330-03	Vulnerability of existing structures to loading outside design conditions	March 31, 1998
1997-0330-05	During RF10 Cracks in the interior wall of the SSW basin	October 31, 1999
1997-0330-06	Linear Crack in the SSW B Pump Room Pump Access Hole Plug	November 23, 1999

B.1.41 Service Water Integrity (XI.M20)

Condition Reports (CR-GGN-):

2007-00370	2009-01046	2010-01333	2011-04353
2007-05634	2009-01222	2010-01990	2011-07189
2008-02874	2009-01943	2010-03814	2012-09699
2008-03216	2009-02510	2010-05922	2012-04872
2008-03406	2009-03458	2010-02964	2012-00369
2008-06710	2009-02738	2010-03078	2012-05260
2009-00754	2009-03048	2010-06067	2012-07400
2009-01003	2010-00700	2010-03291	
2009-01006	2010-01236	2011-02384	CR-GLO-2003-0131

Drawings (LRA-):

NUMBER	TITLE	REVISION
M-1061A	P & I Diagram Standby Service Water System Unit 1	64
M-1061B	P & I Diagram Standby Service Water System Unit 1	49
M-1061C	P & I Diagram Standby Service Water System Unit 1	37
M-1061D	P & I Diagram Standby Service Water System Unit 1	39

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report Non-Class I Mechanical, Section 4.11 "Service Water Integrity"	1
GGNS-ME-08-AMM12	Aging Management Review of the Standby Service Water System	0
GGNS-ME-08-AMM29	Aging Management Review of the Plant Service Water System	0

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
	Grand Gulf Nuclear Station Strategic Plan for Open Loops	2
	Standby Service Water System Basin Hanger Inspection Field Data Form – Preliminary, from in-progress Diver Inspections	August 6, 2012
	Technical Data Sheet – Model T20-MFS Plate Heat Exchanger	

NUMBER	TITLE	REVISION/DATE
AECM 90-0007	GGNS Response to GL 89-13	
AL-6XN	Datasheet for AL-6XN alloy used in SSW System Siphon Line	
CCE 2004-0002	Commitment Change related to AECM 90-0007	May 24, 2004
CCE 2006-0002	Commitment Change related to AECM 90-0007	May 2, 2006
CCE 2006-0004	Commitment Change related to AECM 90-0007	October 19, 2006
CCE 2007-0001	Commitment Change related to AECM 90-0007	October 10, 2007
CR-GGN-2007-05840	Root Cause Analysis Report – Fouling Rates for SSW Cooled HXs	May 12. 2009
CR-GGN-2009-03458	Category "B" Higher Tier Apparent Cause Evaluation for Standby Service Water System	July 8, 2009
EC-31409	Installation of Bird Netting at Standby Service Water Cooling Towers A and B to Prevent Fouling of Basins	0
EC-CS-S-008-MULTI	Engineering Standard Pipe Wall Thinning Structural Evaluation	0
Information Notice No. 85-30	Microbiologically Induced Corrosion of Containment Service Water System	April 19, 1985
LO-GLO-2009-00047	Snapshot Self-Assessment Report Standby Service Water System	May 15, 2009
NRC Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment	July 18, 1989
NRC Generic Letter 89-13, Supplement 1	Service Water System Problems Affecting Safety-Related Equipment	April 4, 1990
QA-8-2007-GGNS-1	Quality Assurance Audit Report	July 17, 2007
QA-8-2009-GGNS-1	Quality Assurance Audit Report	April 16, 2009
SPEC-10-00021-G	Spent Fuel Pool Plate and Frame Heat Exchangers	August 19, 2010

Operating Experience:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD02 Section 3.1.25	Operating Experience Review Results – AERM Service Water Integrity	0
GGNS-EP-08-LRD10 Section 3.1.25	Operating Experience Review Results – Aging Management Program Effectiveness, Service Water Integrity Program	0

Procedures:

NUMBER	TITLE	REVISION/DATE
04-1-03-T46-2	Equipment Performance Instruction ‘B’ ESF Switchgear Room Coolers Flow Test	February 15, 2010
04-1-03-Z51-1	Equipment Performance Instruction ‘A’ Control Room Air Conditioner Flow Test	February 15, 2010
07-S-07-211	General Maintenance Instruction Service Level I Coating Condition Assessment	September 17, 2010
17-S-06-22	Performance and System Engineering Procedure – SSW “A” Performance	March 13, 2008
EN-DC-184	NRC Generic Letter 89-13 Service Water Program	1
EN-DC-316	Heat Exchanger Program	2
EN-DC-340	Microbiologically Influenced Corrosion (MIC) Monitoring Program	0
EN-EP-S-039-G	Testing Standard for Safety-Related Heat Exchangers Cooled by Standby Service Water	2
PS-S-001	Localized Pipe Wall Thinning and Crack-like Flaw Evaluation Standard	1

Work Orders:

NUMBER	TITLE	DATE
52422889-01	04103-T46-2 “B” ESF Switchgear Room Coolers Flow Test	August 13, 2012

B.1.42 Structures Monitoring (XI.S6)

Condition Reports (CR-GGN-):

1997-00841	2006-01007
2004-02047	2007-01970

Engineering Requests (ER-):

NUMBER	TITLE	DATE
GG-2002-0047-000	Evaluation of remaining cracks that are not repaired as per ER 1997-0761	February 19, 2002

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Procedures:

NUMBER	TITLE	REVISION
EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2

Work Orders:

NUMBER	TITLE	DATE
00064814	ACT Tower: Reference CR 2005-1442 Lower Portion of Siding	April 14, 2006
00282919	Maintenance Rule Structure Inspections – Auxiliary Building	July 20, 2011

B.1.43 Water Chemistry Controls - BWR (XI.M2)

Condition Reports (CR-GGN-):

2007-01711	2010-01703	2010-04176
2007-02584	2010-03795	2010-08538

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
	Primary/Secondary Strategic Chemistry Plan	6
	Reactor Water, Control Rod Drive, and Final Feedwater Chemistry trends	January 2010 – July 2012

Procedures:

NUMBER	TITLE	REVISION
01-S-08-16	Chemical Treatment Program	21
08-S-03-10	Chemical Sampling Program	49

B.1.44 Water Chemistry Control – Closed Treatment Water System (XI.M21A)

Condition Reports (CR-GGN-):

2008-05988	2010-06785	2010-07892

2010-04480	2010-07065

License Renewal:

NUMBER	TITLE	REVISION
GGNS-EP-08-LRD06	Aging Management Program Evaluation Report	1

Miscellaneous:

NUMBER	TITLE	REVISION/DATE
	Closed Cooling Water Strategic Plan	6
EPRI TR-1007820	Closed Cooling Water Chemistry Guideline Revision 1 to TR-107396	
	Component Cooling Water, Turbine Building Cooling Water, and Diesel Jacket Cooling Water Division 2/3A/3B Chemistry trends	January 2010 – July 2012