UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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NOV 24 2009

Stewart B. Minahan, Vice
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72676 648A Avenue
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SUBJECT: COOPER NUCLEAR STATION - NRC LICENSE RENEWAL INSPECTION REPORT 05000298/2009010

Dear Mr. Minahan:

On August 14, 2009, a U.S. Nuclear Regulatory Commission (NRC) team completed the onsite portion of its inspection of your application for license renewal of your Cooper Nuclear Station. The team discussed the inspection results with Mr. A. Zaremba, Director, Nuclear Safety Assurance, and other members of your staff during an exit meeting conducted on August 14, 2009, and a supplemental exit meeting conducted on November 12, 2009.

This inspection examined activities that support the application for a renewed license for Cooper Nuclear Station. The inspection addressed the processes of scoping and screening plant equipment to select equipment subject to an aging management review, and 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 systems, structures or components, to verify license renewal boundaries, and to observe any effects of equipment aging. The visual examination of structures, systems, and components also included some areas not normally accessible, which included cable vaults. These NRC inspection activities constitute one of several inputs into the NRC review process for license renewal applications.

The team concluded that your staff generally implemented the screening and scoping of nonsafety-related structures, systems, and components (required in 10 CFR 54.4(a)(2)) and conducted the aging management portion of the license renewal activities, 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 caused your staff to supplement or amend the application, programs, or procedures.

Overall 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 taken 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. However, the team identified one area of concern related to the adequacy of the containment wetwell (torus) coating. Specifically, the team determined that you have identified a large amount of general corrosion and localized pitting during each of the last three inspections (approximately 600 each inspection) on the wetted surface of your containment suppression pool liner (torus). While we recognize that you appear to be meeting the ASME Code requirements to assure structural integrity of the containment liner, additional review is needed to determine whether you have established a program to manage the effects of aging for the wetwell during the period of extended operation. Therefore, the staff will continue to review this issue.

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,

Neil O'Keefe, Chief
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Docket: 50-298
License: DPR-46

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	05000298
License:	DPR-46
Report:	05000298/2009010
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Avenue Brownville, NE 68321
Dates:	Onsite weeks July 27 – 31 and August 10 - 14, 2009, and in-office review through November 12, 2009
Inspectors:	G. Pick, Senior Reactor Inspector, Engineering Branch 2, Division of Reactor Safety
	G. Meyer, Senior Reactor Inspector, Engineering Branch 1, Division of Reactor Safety, Region I
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Accompanying Personnel:	S. CuadradoDeJesus, Reactor Engineer, Nuclear Safety Professional Development Program, Division of License Renewal, Office of Nuclear Reactor Regulation
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Approved By:	Neil O'Keefe, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000298/2009010; 07/27/2009 - 11/12/2009; Cooper Nuclear Station; Scoping of nonsafety-related systems and review of the aging management programs for the Cooper Nuclear Station application for a renewed license

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

The team concluded the applicant performed screening and scoping of nonsafety-related structures, systems, and components as required in 10 CFR 54.4(a)(2). Generally, the applicant implemented the aging management programs as described in the license renewal application. 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 areas that resulted in changes to the application, programs, and procedures.

Overall 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 taken 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. However, the team identified one area of concern related to the adequacy of the containment wetwell (torus) coating. Specifically, the team determined that you have identified a large amount of general corrosion and localized pitting during each of the last three inspections (approximately 600 each inspection) on the wetted surface of your containment suppression pool liner (torus). While we recognize that you appear to be meeting the ASME Code requirements to assure structural integrity of the containment liner, additional review is needed to determine whether you have established a program to manage the effects of aging for the wetwell during the period of extended operation. Therefore, the staff will continue to review this issue

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

No findings of significance were identified

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA5 Other - License Renewal

a. Inspection Scope (IP 71002)

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

For scoping of nonsafety-related structures, systems, and components, the team selected a number of systems, components and structures for review to determine if the methodology applied by the applicant appropriately addressed the nonsafety-related systems affecting the safety functions of a system, structure, or component within the scope of license renewal.

The team selected a sample of aging management programs 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 the applicant personnel to confirm the accuracy of the License Renewal Application conclusions. For a sample of plant systems and structures, the team walked down of accessible portions of the systems to observe aging effects. During the plant walk downs, the team reviewed the material condition of the structures, systems, and components.

b.1 Scoping of Nonsafety-Related Structures, systems, and components

For scoping and screening, the team reviewed (1) the applicant's program guidance procedures and (2) summaries of scoping and screening results for the facility to assess the thoroughness and accuracy of the methods used to bring structures, systems, and components within the scope of the License Renewal Application. Further, the team assessed the applicant's activities related to scoping nonsafety-related structures, systems, and components, as required in 10 CFR 54.4(a)(2). The team verified 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. Specifically, the team assessed whether the applicant evaluated: (1) nonsafety-related structures, systems, and components within the scope of the current licensing basis, (2) nonsafety-related structures, systems, and components directly connected to safety-related structures, systems, and components,

and (3) nonsafety-related structures, systems, and components not directly connected but spatially near to safety-related structures, systems, and components, respectively.

The team reviewed the complete set of license renewal drawings, which had been color-coded to indicate systems and components in scope for 10 CFR 54.4(a)(1), (a)(2) and (a)(3). The team interviewed personnel, reviewed program documents and independently walked down numerous areas within the plant. The team confirmed that the applicant: (1) included the appropriate structures, systems, and components within the license renewal scope; (2) established an acceptable basis to exclude structures, systems, and components excluded from the license renewal scope; and (3) appropriately determined the license renewal scope boundaries for the systems, including seismic supports and anchors.

The in-plant areas and systems walked down included the following:

- Control Building
- Controlled Corridor
- Critical Switchgear Rooms
- Diesel Generator Room 2
- Elevated Release Point Tower and Z Sump
- Fire Pump House
- High Pressure Coolant Injection Room
- Intake Structure and Service Water Room
- Offgas Filter and Fan Building
- Reactor Building
- Standby Liquid Control System
- Turbine Building

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

For structures, systems, and components selected because of potential structural interaction (seismic design of safety-related components dependent upon nonsafety-related components), the team determined that the applicant accurately identified and categorized the structural boundaries within the program documents. Based on independent sampling of the isometric drawings and the seismic boundary determinations, the team determined that the applicant appropriately identified the seismic design boundaries and correctly included the applicable component types in the license renewal application.

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

b.2 New Aging Management Program Evaluations

The applicant had identified 40 aging management programs required to manage the effects of aging that included 11 new aging management programs and 29 existing aging management programs. The team reviewed 10 of the 11 new aging management programs at Cooper Nuclear Station to determine whether the licensee had actions planned to manage the effects of aging.

At the time of the inspection, the applicant had described a number of new programs within the application but had not completed many of the elements identified in the programs. Therefore, generally, the team could not assess the effectiveness of the implementation of these proposed programs. Some of the new programs are one-time programs that will involve testing of applicable components within the 4½ years prior to the period of extended operations to confirm the absence of significant aging effects. If the results confirm the presence of aging effects, the program will be required to establish a set of additional actions to manage the effects of aging.

Also, industry operating experience that formed the bases for these new programs is described in the operating experience element of NUREG-1801, "Generic Aging Lessons Learned (GALL Report) Tabulation of Results," Volume 2, Revision 1 (hereafter referred to as the GALL Report) program description. The team reviewed site-specific operating experience to determine whether any aging effects for the systems and components within the scope of these programs were outside the bounds of industry operating experience.

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

.1 B.1.1 Aboveground Steel Tanks Program

The Aboveground Steel Tank Program is a new program that the applicant determined required an enhancement to be consistent with the GALL Report. The program will manage aging effects caused by loss of material from external surfaces of outdoor, aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations that are inaccessible for external visual inspection. As an enhancement, the applicant will perform the thickness measurements at least once during the first 10 years of the period of extended operation and periodically thereafter. The results of this initial inspection will be used to determine the frequency of subsequent inspections.

The team reviewed license renewal application, the NRC aging management program audit and any licensee responses to requests for additional information. The team used key words to identify any relevant condition reports in the corrective action database. The team assessed whether any identified condition reports changed the applicant's assessment of this aging management program. The team interviewed plant personnel and conducted walk downs of the firewater storage tanks, which were the only tanks

within the scope of this program. The applicant had not developed an implementing procedure or process at the time of this inspection; consequently, the team could not assess the effectiveness of the program implementation.

The team could not visually inspect the exterior coating of the tanks since the tanks had a metal skin covering thermal insulation on their exterior. The team concluded the applicant would need to remove portions of the metal skin during periodic system walk downs to be consistent with the GALL Report. Since the metal skin impeded visual observation of the tank exterior, the team questioned how the applicant could inspect the exterior skin of the tank. As a result, the applicant developed a plan and initiated actions to remove the current insulation, inspect the current condition of the outer surface of the tanks, take corrective actions if necessary, and apply polyurethane wall foam coated with silicone. The applicant initiated Work Orders 4703937 and 4715927 to remove the insulation and recoat the Fire Water Storage Tanks A and B, respectively. The applicant stated the new configuration will provide thermal insulation, create an air-tight and water-tight seal over the carbon steel structure, and allow for the direct visual inspection of the exterior coatings of the tank during periodic walk downs consistent with the GALL Report.

In addition, the team noted that the applicant did not have any documentation to demonstrate that the tanks were installed with a seal at the interface edges between the tanks and concrete foundations. The GALL Report recommends the use of such seals to mitigate corrosion at the bottom surfaces of the tanks by preventing water and moisture from penetrating the interfaces. On September 4 and 21, 2009, the applicant inspected the exterior of the Fire Water Storage Tanks A and B, respectively. The applicant determined general corrosion on the tank exterior and bolting. The applicant determined that no steel to concrete interface sealant existed. The applicant initiated Condition Report 2009-07305 that documented the need to reinsulate the exterior of the fire water storage tanks and to apply a foam sealant to the tank bottom-to-concrete surface interface in order to be consistent with the GALL Report.

For the Aboveground Steel Tank Program, the team concluded that with the planned changes the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on low alloy steel components in wet systems. The team concluded that, if implemented as described, the applicant will have developed a method to appropriately manage the affects of aging during the period of extended operation.

.2 B.1.3 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program, consistent with the GALL Report, credited with managing the effects of corrosion on the pressure-retaining capability of carbon steel, gray cast iron or ductile iron components and assessing the condition of stainless steel components. The applicant will evaluate their capability to manage the effects of aging through inspection either during an excavation for other maintenance (opportunistic) or during a specifically planned excavation. The applicant will perform one excavation prior to the period of extended operation and one excavation within the first 10 years of the period of extended operation. The team noted that the applicant had initiated development of procedures for excavation, evaluation of existing

coatings, and recoating of any damaged areas; however, the applicant had not drafted a formal procedure; consequently, the team could not assess the effectiveness of the program implementation.

The team reviewed the license renewal application, the NRC aging management program audit, and any licensee responses to requests for additional information. The team also interviewed the buried pipe program owner. The team concluded that applicant appropriately concluded that no operating experience identified any new aging mechanisms by review of search results using the word "excavation" in the corrective action database.

The team reviewed the applicant's resolution and root causes associated with a 2004 buried diesel fuel oil piping leak and a 2009 buried fire protection line leak. Also, the team concluded the applicant initiated appropriate long-term actions from review of a 2006 self-assessment of buried piping, tanks and structures. The team noted that the applicant has initiated corrective actions for their cathodic protection system, which was installed during initial construction and was not credited in the application, but would assist in protecting buried piping.

For the Buried Piping and Tanks Inspection Program, the team concluded that the applicant had performed appropriate evaluations of their piping conditions and considered pertinent industry experience and plant operating history to determine the effects of aging on buried piping and tanks. The team concluded that, if implemented as described, the applicant would have developed a method to appropriately manage the affects of aging during the period of extended operation.

.3 B.1.22 Metal-Enclosed Bus Inspection Program

The Metal-Enclosed Bus Inspection Program is a new program that is credited with managing the aging affects associated with loosening of bolted bus bar connections and reduced insulation and insulator resistance on bus ducts. The applicant included the bus ducts and the transmission lines because they supported the station blackout regulations. The specific components affected included the non-segregated phase bus between the Emergency Station Service Transformer and 4.16 kV Safety Switchgear Buses 1F and 1G and the non-segregated phase bus between the Start-up Station Service Transformer X winding and 4.16 kV Non-Safety Switchgear Buses 1A and 1B. These inspections will include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required. Internal portions of the Metal-Enclosed Buses will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports will be inspected for structural integrity and signs of cracks.

This program will be completed before the period of extended operation. A sample of accessible bolted connections covered with heat shrink tape or insulating boots per manufacturer's recommendations will be inspected using quanititative or qualitative methods. Where the applicant only performs visual inspections, these inspections will be performed at least once every five years for insulation material surface anomalies.

Where inspections include quanititative measurements, then the inspections must be performed at least once every 10 years.

The applicant took an exception to the GALL report because structural inspections of the metal-enclosed bus enclosure assembly will be monitored and performed in this program instead of the Structures Monitoring Program. The metal-enclosed bus enclosure assembly external surfaces will be visually inspected for evidence of loss of material and elastomer degradation. The team determined that the applicant had not yet modified their procedures to account for these structural inspections of the metal-enclosed bus structures. The applicant indicated the procedures would be modified prior to their next examination.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures and preventive maintenance requirements. In addition, the team searched the applicant's corrective action database for relevant condition reports using key word searches. The team interviewed the license renewal project personnel and the responsible plant and design engineers. The team conducted plant walk downs of the non-segregated bus ducts and the overhead transmission lines and towers. The team reviewed the transmission line inspection procedure that Nebraska Public Power District used to inspect the lines throughout their transmission and distribution network as an example of how to monitor the effects of aging for wooden transmission poles.

The team determined that the applicant had established a preventive maintenance program to inspect and clean bus ducts on site along that included these non-segregated bus ducts in response to bus duct failures at other facilities in the early 1990s. The team reviewed the results of these preventative maintenance activities, including the resolution of condition reports. During interviews and review of documents, the team verified the applicant had corrected the identified deficiencies during the preventative maintenance activities.

For the Metal-Enclosed Bus Inspection Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on the metal enclosed non-segregated bus ducts. The team concluded that, if implemented as described, the applicant would have developed a method to appropriately manage the affects of aging during the period of extended operation.

.4 B.1.24 Non-Environmentally Qualified Bolted Cable Connections Program

The Non-Environmentally Qualified Bolted Cable Connections Program is a new, plant specific, one-time inspection program that will evaluate the as-found condition of the metallic parts of cable connectors. The program will assess whether loosening of bolted connections because of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation had occurred prior to the period of extended operation. The applicant specified they will evaluate a representative sample of electrical connections within the scope of license renewal and subject to aging management review based upon the service application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration,

etc.). The applicant will document technical basis for the sample selected and the acceptance criteria used for each inspection or test will be defined by the specific type of inspection or test performed for the specific type of cable connections. The applicant had not developed a specific sample size at the time of the inspection.

The team reviewed license renewal program basis documents and aging management review documents. In addition, the team searched the applicant's corrective action database for relevant condition reports. Because this is a new one-time inspection program, the applicant had not developed any program or procedure for performing these inspections to verify whether a periodic aging management program would be required. During interviews with license renewal project personnel and the applicant, the applicant described that they will implement a process as described in Report CNS-RPT-07-AME01, "Aging Management Review of Electrical Systems," Revision 1. During interviews, the applicant indicated that the sampling process was expected to confirm that aging effects had not occurred in bolted connections; consequently, if any connection had indications of an aging affect, the program once established would require performing an expanded sample. From review of identified condition reports, the team concluded that failures experienced by the applicant resulted from poor maintenance practice and did not result from aging affects.

For the Non-Environmentally Qualified Bolted Cable Connections Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry and plant operating experience to determine the effects of aging on metal portions of bolted connections. The team concluded that, if implemented as described during interviews, the applicant would appropriately identify and address aging effects during the period of extended operation.

.5 B.1.25 Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program

The Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program is a new program, consistent with the GALL Report, credited with managing the aging effects for inaccessible medium-voltage cables exposed to significant moisture simultaneously with applied voltage. The applicant plans to manage the aging effects by periodic inspection for water collection in cable manholes and conduit, and draining water as needed. The applicant will periodically test in-scope cables to provide an indication of the condition of the conductor insulation. The applicant will complete the testing of the medium-voltage prior to entering the period of extended operation and once every 10 years thereafter. Because the inaccessible medium voltage cables have a sump pump and a high level alarm, the applicant plans to visually inspect the condition of the cables and other structures in the manholes for aging effects every 2 years during sump pump preventative maintenance activities.

The team reviewed license renewal program basis documents, aging management review documents, existing plant procedures, and completed maintenance activities. In addition, the team searched the applicant's corrective action database for relevant condition reports. The team interviewed plant personnel and worked with the resident inspection staff to have the underground cable vaults walked down. The applicant did not have any existing procedures for performing cable vault inspections or the condition monitoring of the medium voltage cables.

The team determined that the service water pump motors and a feeder on the north loop for the motor-driven fire pump had cables that required monitoring for aging effects. The team determined that the applicant had sump pumps installed in the underground cable vaults and that operators would receive an alarm in the control room on a Hi-Hi sump level. The team reviewed completed megger tests for the service water pump motors. The team concluded the applicant tested the cables along with the motor windings since the megger was connected at the motor control center.

For the Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for inaccessible cables. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.6 B.1.27 Non-Environmentally Qualified Insulated Cables and Connector Program

The Non-Environmentally Qualified Insulated Cables and Connections Program is a new program, consistent with the GALL Report, credited with managing the aging effects in cables and connections exposed to adverse localized environments. The aging effects managed included embrittlement, melting, cracking, swelling, surface contamination or discoloration of cables in accessible areas. The applicant plans to monitor the aging effects through periodic visual inspections to identify jacket surface anomalies of in-scope cables in adverse environments and engineering evaluations of inaccessible in-scope cables. The applicant will complete the first inspection of a sample of these cables prior to entering the period of extended operation and once every 10 years thereafter. At the time of the inspection the applicant had not established a sample size for evaluation.

The team reviewed license renewal program basis documents and aging management review documents. In addition, the team searched the applicant's corrective action database for relevant condition reports. The team interviewed plant personnel related to their plans for developing a procedure and conducting these aging effects evaluations. Plant personnel described that their program will be closely modeled and incorporate the guidance in Electric Power Research Institute Report TR-109619, "Guideline for Management of Adverse Localized Environments."

For the Non-Environmentally Qualified Insulated Cables and Connections Program, 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, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.7 B.1.29 One-Time Inspection Program

The One-Time Inspection Program is a new program, consistent with the GALL Report, credited with verifying the effectiveness of other aging management programs. The program will verify effectiveness of the Water Chemistry Control, Diesel Fuel Monitoring, and Oil Analysis Programs through non-destructive evaluation of a sample of components maintained by these chemistry programs. Non-destructive evaluation will be performed by qualified personnel using procedures and processes consistent with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code and 10 CFR Part 50, Appendix B. The One-Time Inspection Program will not involve periodic inspections, and the applicant will implement these inspections prior to the period of extended operation. The team noted that the applicant had initiated development of procedures for identifying the sample locations and for increasing the inspection sample size in the event the applicant identifies aging effects in the systems; however, the applicant did not have a formal procedure developed for the team to review.

The team reviewed the license renewal application, the NRC aging management program audit, and any licensee responses to requests for additional information. The team evaluated the basis used to identify the inspection sample, and the team discussed the planned activities with the responsible staff. The team also reviewed site-specific operating experience within the Operating Experience Review Report (67 events over the period 2002 – 2007) and determined that no additional aging effects existed.

For the One-Time Inspection Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described, the applicant will provide guidance to appropriately identify and address aging effects during the period of extended operation.

.8 B.1.30 One-Time Inspection – Small Bore Piping Program

The One-Time Inspection – Small Bore Piping Program is a new program credited with managing the effects of cracking in Class 1 piping of 4 inches and smaller. The applicant currently monitors for cracking in small-bore piping equal to 4 inches in diameter. The applicant had not developed a program or procedure for performing these examinations. The applicant indicated the examinations will be performed as part of the inservice inspection program and take into account the current industry information provided by the Boiling Water Reactor Vessel Internals Project (BWRVIP) related to thermal fatigue susceptibility. The applicant will perform these examinations one time prior to the period of extended operation on small bore piping, which includes orifices, fittings, piping, valve bodies and any other pressure retaining parts.

In addition, the applicant took an exception to the GALL Report since they will evaluate selected welds on less than 4 inch diameter stainless steel piping, as specified in the risk-informed inservice inspection program. The risk informed inservice inspection program requires ultrasonic volumetric examinations on selected weld locations to detect cracking, which already incorporated 4-inch diameter piping.

The team reviewed license renewal program basis documents, aging management review documents, and industry documents related to thermal fatigue on small bore piping. In addition, the team searched the applicant's corrective action database for relevant condition reports and interviewed plant personnel.

For the One Time Inspection –Small Bore Piping Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in small-bore Class 1 piping. The team concluded that, if implemented during each 10-year inservice inspection interval, the applicant would ensure aging effects are appropriately identified and addressed during the period of extended operation.

.9 B.1.34 Selective Leaching Program

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

The team reviewed the license renewal application, the NRC aging management program audit, and any licensee responses to requests for additional information. The team evaluated the basis used to identify the inspection sample, and the team discussed the planned activities with the responsible staff. The team also reviewed site-specific operating experience within the Operating Experience Review Report (67 events over the period 2002 – 2007) and agreed that no additional aging effects existed.

For the Selective Leaching Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in components and systems that have metal alloys subject to this mechanism. The team concluded that, if implemented as described, the applicant would provide guidance to appropriately identify and address aging effects during the period of extended operation.

.10 B.1.37 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is a new program that manages the aging effect of reduction of fracture toughness of cast austenitic stainless steel components because of thermal aging and neutron irradiation embrittlement. The program will be an evaluation and inspection program. This aging management program will screen cast austenitic stainless steel components to identify those that are potentially susceptible to reduction of fracture toughness on the basis of casting method, molybdenum content, and ferrite content. For any component determined to be susceptible to a reduction in fracture toughness, the

applicant will examine the components using a supplemental examination to identify whether cracks exist. The inspection technique will be capable of detecting the critical flaw size determined based on the service loading condition and service degraded material properties. The applicant had not established a periodicity for examination at the time of the inspection.

The team reviewed license renewal program basis documents and aging management review program documents. In addition, the team searched the applicant's corrective action database for relevant condition reports and interviewed plant personnel. During the aging management review of the reactor vessel internals, the applicant identified that the jet pump castings, control rod guide tube bases, and fuel support pieces as components made of cast austenitic stainless steel. The applicant specified they will consider the data presented in NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," Revision 1 in the susceptibility screening. The applicant had not developed a program or procedure to perform the inspection and evaluation of cast austenitic stainless steel components potentially subject to a loss of fracture toughness. During interviews, the team determined that the applicant intends to implement a Boiling Water Reactor Vessel Internals Project document (currently in draft) that will provide a method to perform these evaluations.

For the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program, the team concluded that the applicant had established plans to develop a program to address aging effects that reduce the fracture toughness of identified components. Further, the applicant had considered pertinent industry experience and plant operating history to determine the effects of aging on cast austenitic stainless steels. The team concluded that, if implemented as described in their aging management program evaluation and as described during interviews, the applicant would appropriately identify and address aging effects during the period of extended operation.

b.3 Existing Aging Management Program Evaluations

The team sampled 13 of the 29 existing aging management programs at Cooper Nuclear Station to determine whether the licensee had actions planned to manage the effects of aging.

Also, industry operating experience that formed the bases for these existing programs is described in the operating experience element of the GALL Report. The team reviewed site-specific operating experience to determine whether any aging effects for the systems and components within the scope of these programs were outside the bounds of industry operating experience.

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

The team conducted walk downs of selected in-scope structures, systems and components, if possible, to assess how the applicant maintained plant equipment under the current operating license and to visually observe examples of nonsafety-related equipment determined to be in scope because of their proximity to safety-related equipment and their potential for failure as a result of aging effects.

.1 B.1.2 Bolting Integrity Program

The Bolting Integrity Program is an existing program that required enhancements to be consistent with the GALL Report. The Bolting Integrity Program manages the aging effects related to cracking, loss of material, and loss of preload for pressure retaining bolting and American Society of Mechanical Engineers component support bolting. The applicant evaluates bolting for signs of cracking, corrosion and other material losses, leakage and loss of preload. As enhancements the applicant specified they will: (1) include guidance from Electric Power Research Institute Reports NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants - Volume 1" and TR-104213, "Bolted Joint Maintenance & Applications Guide," to address material selection and testing, bolting preload control, inservice inspection, plant operation and maintenance, and evaluation of the structural integrity of bolted joints; (2) provide guidance from the above reports for replacing non-Class 1 bolting and disposition of degraded structural bolting; and (3) clarify actual yield strength is used in selecting materials for low susceptibility to stress corrosion cracking, clarify the prohibition for use of molybdenum sulfide for bolts and clarify the requirement to visually verify gasket compression. The applicant will implement these procedure and process improvements prior to the period of extended operation.

The team reviewed license renewal program basis documentation, inspection reports, condition reports, site procedures, and related references used to manage the aging effects related to bolting within these programs. The team performed field walk down inspections of various systems to evaluate the effectiveness of the existing program. The applicant provided documentation that demonstrated personnel had evaluated the condition of bolts in structural fixtures and mechanical equipment.

For the Bolting Integrity Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on low alloy steel components in wet 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 B.1.10 Containment Inservice Inspection Program

The Containment Inservice Inspection Program is an existing program that required enhancements to be consistent with the GALL Report. This program visually examines the accessible surfaces of the steel liner of the reinforced concrete primary containment (including Mark I drywell and torus) and its integral attachments. As enhancements the applicant specified they will: (1) require visual inspection of accessible surfaces and, for inaccessible surfaces requiring an augmented examination, ultrasonic thickness

measurements would be used; (2) document material loss in a local area exceeding 10 percent of minimum wall thickness or projected to exceed 10 percent of minimum wall thickness prior to next scheduled examination, as specified in American Society of Mechanical Engineers, Section XI, Subsection IWE; and (3) ensure the drywell sand cushion drain lines are vacuum tested prior to the period of extended operation. Title 10 Code of Federal Regulations Part 50.55a and Section XI, Subsection IWE specify the regulatory requirements for this program. The applicant has completed the first interval (approximately 10 years) of Subsection IWE inspections and will schedule inspections during future intervals as specified in Section XI. The team reviewed the implementing program and procedures and found them to be appropriate.

The team reviewed the license renewal application, the NRC aging management program audit, and any applicant responses to requests for additional information.

Drywell Aging Management

The team interviewed the inservice inspection program owner and applicable civil engineers. Regarding the drywell, the team evaluated plant operating history and the applicant's response to Generic Letter 87-05, "Request For Additional Information-Assessment Of Applicant Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells," to determine whether leakage on the outside of the drywell had occurred that would merit ultrasonic test examination. The team found no documented evidence of prior leakage occurring. Initially, the applicant stated that no previous ultrasonic test examinations had occurred. After the team challenged the applicant regarding the condition of the drywell and the requirements in Generic Letter 87-05, the applicant located ultrasonic test measurements of the drywell above the sand bed region that had been performed in 1986 and had found thickness to be slightly above nominal. The team determined that the nomenclature for the two refueling bellows associated with the drywell was confusing and could have resulted in procedural actions for sand bed drain leakage to be incorrect. The applicant wrote Condition Report 2009-06131 to consider improvements to the procedure.

For the Containment Inservice Inspection Program, the team concluded that the applicant had performed appropriate evaluations of existing plant conditions and considered pertinent industry experience and plant operating history to determine the effects of aging on the primary containment. The team determined that applicant had established a program to manage the effects of aging for the drywell. The team concluded that, without any further significant degradation, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

Wetwell (Torus) Aging Management

The team reviewed the results of the Section XI, Subsection IWE inspections to assess the effects of aging. The applicant began performing the Section XI, Subsection IWE-required 100 percent wetted area torus inspections in 2001. Because the torus had a continuously wetted surface with evidence of pitting, the applicant categorized their torus as Category E-C. The team evaluated the torus inspection results from 2001, 2005 and 2008 with selected torus inspection results listed below:

Table 1 – Torus Inspection Result Summary

Evaluation Subject	2001 Outage	2005 Outage	2008 Outage
Total Pits Identified	883	567	641
Total Reportable Pits	80	1	26
Total Shallow Pits Repaired	883	567	641
Total Area Repaired (sq ft)	77.5	12.7	12.1
Sludge Removed (lbs)	1163	2946	3120

The torus acts as the containment liner and contains the suppression pool water and components. It is made of carbon steel, with thicknesses of the torus wall ranging from 0.616 inches in the general shell to 1.1875 inches at the ring girder joints and at the penetrations. Because carbon steel is susceptible to corrosion, it is coated with a zinc-based paint. The zinc acts as a sacrificial anode, which is consumed over time.

The torus has historically collected sludge and corrosion products, resulting in murky water and solid deposits that appear to exceed what is typical for boiling water reactors of that vintage. The applicant does not have a cleanup system to help maintain the water chemistry in the suppression pool. The coating applied to the inside of the torus is the original un-top-coated zinc-based paint, which has worn and been locally damaged. In areas where the coating is degraded or missing, the containment liner has experienced corrosion. Below the waterline in the suppression pool, there is significant pitting corrosion. The torus coating repairs performed following the installation of the tee quenchers had begun to degrade.

The team reviewed inspection results that indicated 2091 pits have been identified in the wetted surface of the suppression pool containment liner. This is an active problem, as hundreds of new pits were identified at each inspection. The team reviewed inspection videos from the last torus inspection and noted areas with exposed metal and significant general corrosion, including catwalk bracing, tee quencher piping and supports, ring girders, downcomer bracing, and near penetration regions on the shell. Corrosion on structures and supports undergoing generalized corrosion contributed to the increasing volume of sludge being removed, indicating the problem is getting worse with time. The applicant has documented in a 2001 inspection that the torus coating system was in fair to poor condition. The team noted that the applicant has not scheduled any actions to correct this condition.

The applicant's evaluations show that the pitting corrosion does not have a significant affect on the torus structurally. The applicant performed a stress evaluation in accordance with the American Society of Mechanical Engineers, Section III, Subsection NE. From this evaluation, the applicant identified a minimum wall thickness of 0.153 inches. The team reviewed design calculations that established acceptance criteria for identified pits and provided coating repair criteria. All pits evaluated by the applicant remained well within the structural integrity acceptance criteria. The applicant coated all pits that measured greater than 0.030 inches near penetrations and 0.050 inches near ring girders. Although no pitting on the general shell required repair, the

torus general shell had dense pitting at localized areas without coating that ranged from one to two mils deep with occasional depths of 40 to 50 mils.

The applicant was taking the following actions to manage the corrosion:

- Visually inspect 100 percent of the wetted surface of the torus once each period as specified in their 10-year inservice inspection plan to identify pitting locations and measure pit depth

- Pits that exceed a threshold (values vary by location) were covered with an epoxy coating that cures underwater to arrest corrosion

- Pits that do not exceed the threshold were monitored for growth at the next inspection

- All pits that were identified were recorded on a pit map

- The applicant has considered coating repairs or replacement, but has not scheduled any action

Based on the above, the team needed additional information to determine whether the applicant would effectively manage the effects of aging in the wetwell. The inspectors had the following observations and concerns:

The expected life of the original coating was not documented in the final safety analysis report or other documents reviewed by the inspectors. A review of general information on this type of coating seems to indicate that the coating used at Cooper Nuclear Station should not be expected to have a 40-year service life. In addition, the inspection reports provided to the applicant discuss that un-top-coated zinc coatings have on average an expected life of 15 years. Based on the current degree of coating failure, it does not appear that the existing coating is suitable for another 20 years or service. Depletion of the zinc has reduced the ability to provide corrosion protection to the exposed steel substrate and localized coating failures have exposed areas of bare steel. If the zinc remained available in sufficient quantities, localized bare metal surrounded by intact coating should not be exhibiting active corrosion as it has been.

The applicant has not been managing the coating failures by making coating repairs to areas that have had localized coating failures, whether above or below the waterline. This has apparently resulted in localized galvanic corrosion with high corrosion rates (pitting), instead of very low and predictable general corrosion rates. It has also contributed to the amount of sludge and corrosion products collecting in the suppression pool. Instead, the applicant has been allowing corrosion and applying an epoxy coating intended to arrest the pitting. The applicant was attempting to manage the pitting corrosion in the context of structural integrity without correcting the causes. The available data indicate that the condition worsened over time, so this method of aging management is not being successful. Pitting corrosion rates are typically much higher and less predictable than general corrosion rates, and a through-wall pit would impact containment integrity without necessarily impacting structural integrity.

The inspectors concluded that while the applicant met their obligations under the ASME Code, so this is not a current safety concern. However, the ASME Code does not address consideration of plant life extension or determination of when a coating should be replaced.

Because additional information is needed to determine whether the applicant had established a program to manage the effects of aging for the wetwell during the period of extended operation, this issue will be tracked as an unresolved item:
URI 05000298/2009010-01, Adequacy of aging management for the torus.

.3 B.1.11 Containment Leak Rate Program

The Containment Leak Rate Program is an existing program, consistent with the GALL Report; however, the applicant took exceptions to the Gall Report that involved three previously approved exemptions to the requirements of 10 CFR Part 50, Appendix J. The Containment Leak Rate Program uses Type A, Type B, and Type C leakage rate tests of primary containment pressure-retaining components. The program manages aging effects that include loss of material and cracking of carbon steel, cracking of stainless steel, and cracking and material property changes in elastomer sealants and seals. The team determined that the applicant will continue to perform leak rate testing during the period of extended operation to monitor leakage rates through the containment shell and associated welds, penetrations, fittings and other access openings.

The team reviewed the bases for the three exemption requests to identify if they would affect the ability of the applicant to manage the effects of aging during the period of extended operation. The approved exemptions from 10 CFR Part 50, Appendix J, allowed the applicant to

(1) Conduct reverse direction Type C local leak rate testing of four containment isolation valves because this conservatively tests the disk seat and other means, including the Type A integrated leak rate testing, reasonably assured the leak tightness of the bonnet and packing boundaries

(2) Conduct Type C local leak rate testing of the main steam isolation valves at 29 psig since this provides reverse loading of the inboard valves and a greater, conservative measured leak rate. Conduct expansion bellows testing at 5 psig between the plies because a higher pressure cannot be achieved, because the bellows have no moving parts, and the bellows are tested during the integrated leak rate test

(3) Not meet the performance-based leakage requirements described in Option B, Sections III.A and III.B because the applicant provided a separate radiological consequence term for the main steam isolation valve leakage pathways. The revised design basis radiological consequences analyses address leakage through these pathways as individual factors, exclusive of the primary containment leakage.

The team reviewed the license renewal application, the NRC aging management program audit, and any licensee responses to requests for additional information. The team interviewed responsible engineers, reviewed condition reports, and examined the results of the past two local leak rate tests. The team determined that the exemptions did not affect the ability of the program to manage the effects of aging.

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

.4 B.1.12 Diesel Fuel Monitoring Program

The Diesel Fuel Monitoring Program is an existing program that required enhancements to be consistent with the GALL Report Fuel Oil Chemistry Program. The Diesel Fuel Monitoring Program manages the loss of material and cracking aging effects on internal surfaces of the diesel fuel oil system piping, piping components, and tanks by minimizing the potential for a corrosive environment and verifying that the applicant has taken effective actions to mitigate corrosion. The tanks affected by this program include the diesel fuel oil storage tanks, the diesel fuel oil day tank and the diesel fire pump fuel oil storage tank.

The planned enhancements included: (1) using Standard D4057, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," for the diesel fire pump storage tank; (2) periodic visual inspections and cleaning of the affected tanks; (3) periodic multilevel sampling of the diesel fuel oil day tank and diesel fire pump storage tank and ultrasonic bottom surface thickness measurements of the affected tanks; (4) added acceptance criteria of less than or equal to 10 milligram per liter for the diesel fire pump fuel oil tank; and (5) establish appropriate acceptance criteria for the tank bottom ultrasonic thickness measurements, based upon as-built drawings adjusted for a corrosion allowance – establish criteria to require engineering evaluation.

In addition, the applicant identified exceptions to the GALL Report that deviated from the specified recommendations to use American Society of Testing and Materials Standards. In one instance, the applicant used only one of two standards recommended and in another instance the applicant used a different method to determine particulates than that recommended. The team interviewed chemistry personnel and evaluated the content of the standards being used. The team did not identify any concerns.

The team reviewed license renewal program basis documents, aging management review documents, existing surveillance procedures, and surveillances results. In addition, the team searched the corrective action database for relevant condition reports and evaluated the license use of industry information. The team interviewed plant personnel and conducted walk downs of the emergency diesel generators, emergency diesel generator day tanks, and associated piping and components. At the time of this inspection, the applicant had not developed or modified existing procedures to

implement the enhancements described in their license renewal application and aging management program evaluation report.

The applicant implemented the existing Diesel Fuel Monitoring Program through fuel oil chemistry control, sampling, and receipt inspection activities, as specified in the plant Technical Specifications; American Society of Testing Materials Standards; vendor and plant requirements for fuel oil chemistry; and piping and piping component and tank requirements.

For the Diesel Fuel Monitoring Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on internal surfaces of the diesel fuel oil system piping, piping components, and tanks. With the enhancements to be incorporated prior to the period of extended operation, the team concluded that, if implemented as described, the applicant would have developed a method to appropriately manage the affects of aging during the period of extended operation.

.5 B.1.14 External Surfaces Monitoring Program

The External Surfaces Program is an existing program that required an enhancement to be consistent with the GALL Report. This program is credited with managing loss of material for external surfaces of steel components and hardening and loss of strength for elastomers in ventilation and mechanical systems. This program also manages the aging effects of loss of material for internal surfaces whenever the environments for both internal and external surfaces are similar. The team determined the applicant had already completed external surface inspections prior to the period of extended operation as part of routine system engineer walk downs. The enhancement will clarify procedures and guidance documents to specifically require periodic inspections of systems in scope and subject to aging management review. The inspections will include areas surrounding the subject components to identify nearby hazards and will also evaluate in scope structures, system and components as a result of 10 CFR 54.4(a)(2) evaluations. The applicant included the review of structural elements separately within the Structures Monitoring Program.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures, a set of walk down sheets, and documented walk down results. In addition, the team searched the corrective action database for relevant condition reports and evaluated the license use of industry information. The team interviewed personnel involved with development of the walk down and performed an independent walk down inspection. System engineers had implemented this program by performing inspections of external surfaces of components subject to aging effects. The team concluded that the current program provided an effective method to identify and record the apparent surface conditions of the inspected systems and components.

For the External Surfaces Monitoring Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on the external surfaces of the included components. The team concluded that the program is effective, and will

continue to be effective in managing aging effects of the covered systems and components

.6 B.1.17 Fire Water System Program

The Fire Water System Program is an existing program that required enhancements to be consistent with the GALL Report. These include the fire suppression water system, spray and sprinkler systems, and fire hose stations. The Fire Water System Program manages loss of material in fire protection system components exposed to water through periodic flushing, system performance testing and inspections. Also, much of the system is normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

The planned enhancements included: (1) inspection of hose reels for corrosion, (2) visual inspection of spray and sprinkler system internals to identify corrosion and evaluate to ensure no unacceptable corrosion, (3) wall thickness evaluations of pipe samples using volumetric testing to verify no loss of material from corrosion, and (4) sample of sprinkler heads will be tested or replaced in accordance with National Fire Protection Association 25-2002, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," prior to the sprinklers reaching the 50-year service life. The applicant had not incorporated these enhancements into their program or procedures at the time of the inspection. The applicant will perform the wall thickness measurements prior to the period of extended operation. The applicant will use the examination results to identify the appropriate examination frequency to prevent a loss of function.

In addition, the applicant took exception to the GALL Report recommendations to conduct annual fire hydrant hydrostatic tests and annual hose gasket inspection. The applicant concluded these items did not require aging management review since both types of components already had an inspection and replacement frequency (i.e., not treated as long lived).

The Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components. The applicant conducted tests of these components in accordance with applicable National Fire Protection Association standards to assure the minimum functionality of the systems. The applicant periodically flushed, inspected and performance tested these systems to determine if significant corrosion has occurred. Also, since the applicant maintained many of these systems at required operating pressure, the applicant monitored the systems such that leakage resulting in loss of system pressure would be immediately detected and corrective actions initiated.

The team reviewed completed the periodic hydrant hose tests and inspections of hose gaskets since the applicant had taken an exception to the GALL Report for aging management of these components. The team determined that the procedure the applicant would use to inspect the hydrant gaskets did not contain clear, specific instructions to inspect the hydrant gaskets. As a result, the applicant initiated Procedure

Change Request 48625 to revise the procedure to specifically address hydrant gasket inspections. The team confirmed that the applicant performed the monthly hydrant hoses inspections and replaced gaskets prior to reaching a year from their last hydrostatic test.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures and surveillances, and surveillances results. In addition, the team searched the applicant's corrective action database for relevant condition reports. The team also interviewed plant personnel and conducted walk downs of fire water system equipment, including the fire pumps and associated piping.

For the Fire Water System Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on fire water system internal pipe and component surfaces. With the enhancements to be incorporated prior to the period of extended operation, the team concluded that, if implemented as described, the applicant would have developed a method to appropriately manage the affects of aging during the period of extended operation.

.7 B.1.18 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program is an existing program that required enhancements to be consistent with the GALL Report. The Flow-Accelerated Corrosion Program is an analysis, verification and inspection program that manages the aging affects of wall thinning caused by high-energy fluids in carbon steel and gray cast iron components. The applicant will enhance the Flow-Accelerated Corrosion Program by updating the susceptibility analysis to reflect lessons learned and new technology available after publication of NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," Revision 1, and require training and qualification of personnel implementing the program. The Flow-Accelerated Corrosion Program includes (1) an evaluation to determine critical locations, (2) initial operational inspections to determine the extent of thinning at the critical locations, and (3) follow-up inspections to confirm predictions or to repair or replace components as necessary. The applicant will continue to implement this program each operating cycle during the period of extended operation.

Also, the applicant identified an exception to the GALL Report to use only ultrasonic testing. The team confirmed that the applicant's program predicted component wall thinning using the CHECWORKS software program based on NSAC-202L, Revision 1. However, the GALL Report recommendations were based on NSAC-202L, Revision 2, for carbon steel and bronze components containing high-energy fluids.

The team identified three examples that demonstrated the current Flow-Accelerated Corrosion Program did not meet the recommendations of NSAC-202L, Revision 2, therefore, the GALL Report. Specifically, the applicant had excluded the following potential situations in their flow-accelerated corrosion susceptibility analysis:

- Lines that carry steam with a quality of 99.5 percent or greater. However, NSAC-202L recommends the excluding only lines carrying superheated steam

and cautions not to exclude systems that carry some moisture in off-normal conditions.

- Lines that carry single-phase water at a temperature less than 200°F. However, NSAC-202L cautions that flow-accelerated corrosion can occur on these lines under unusual and severe operating conditions. NSAC-202L states that a system's exclusion should be reconsidered if wear is identified in nearby piping operating at slightly above 200°F.

- Lines fabricated from steel with chromium content of 1.25 percent or greater. However, NSAC-202L cautions not to exclude a high-alloy line if some of its components are carbon steel.

During interviews with plant personnel, the team determined that the applicant committed to reconcile the inconsistencies described above and any others as required to meet the enhancement described in the License Renewal Application.

The team challenged the applicant's basis for taking the exception to the GALL Report. Specifically, the team questioned why the applicant believed they would not need to use radiography tests to evaluate erosion/corrosion. The applicant responded that they had only used ultrasonic testing for evaluating flow-accelerated corrosion in the past because this method provided more complete information related to wall thickness. The team believed the applicant took too narrow of a view. From review of NSAC-202L, the team determined that components with irregular geometries such as valves, orifices, and flow nozzles couldn't be inspected completely with ultrasonic testing techniques. The team questioned what method would be used to evaluation flow accelerated corrosion in these types of components, if needed. Following these discussions, the applicant indicated they would revise their License Renewal Application and change the wording in the exception to allow for methods other than ultrasonic testing. The team determined that the applicant had submitted the revision to the exception in Letter NLS2009062, "Response to Request for Additional Information for the Review of Cooper Nuclear Station License Renewal Application," dated September 24, 2009.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures and surveillances, and surveillance results. In addition, the team searched the applicant's corrective action database for relevant condition reports. The team also interviewed plant personnel.

For the Flow-Accelerated Corrosion Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on carbon steel and gray cast iron internal pipe and component surfaces. With the enhancements to be incorporated prior to the period of extended operation and with the revised wording in the exception, the team concluded that, if implemented as described, the applicant would have developed a method to appropriately manage the affects of aging during the period of extended operation.

.8 B.1.21 Masonry Wall Program

The Masonry Wall Program is an existing program that required enhancements to be consistent with the GALL Report. This program manages the effects of aging in masonry walls by visual examination of each wall for indications of degradation such as cracking, missing/broken blocks, or deteriorated penetrations. The applicant enhanced the Masonry Wall Program by including the 161 KV switchyard control house and to clarify that deficiencies classified as "acceptable with deficiencies" or "unacceptable" would be entered in the corrective action program. The team determined that the applicant had established the program in response to Inspection and Enforcement Bulletin 80-11, "Masonry Wall Design," and Information Notice 87-67, "Lessons Learned from Regional Inspections of Applicant Actions in Response to IE Bulletin 80-11." Masonry block walls provide fire barriers and radiation shielding that have the potential to impact safety-related equipment. The applicant will continue to conduct the periodic evaluations of masonry block walls at the same frequency as they have been performed under the Maintenance Rule program during the period of extended operation.

The team reviewed license renewal program basis documents, aging management review documents, plant procedures, and prior inspection results. In addition, the team searched the corrective action database for relevant condition reports and evaluated the license use of industry information. The team discussed the program with responsible personnel and visually examined accessible masonry block walls to assess their condition. The team determined that the applicant had: (1) developed effective procedures to track changes to masonry wall conditions and (2) performed inspections to substantiate the masonry wall analyses and classifications.

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

.9 B.1.28 Oil Analysis Program

The Oil Analysis Program is an existing program, which required enhancements to be consistent with the GALL Report. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. The enhancements included: (1) adding viscosity, neutralization number and flash point determination of oil samples from components that do not have routine oil changes, along with analytical ferrography and elemental analysis for identifying wear particles, (2) screening for particulate and water content for oil replaced periodically and (3) formalizing preliminary oil screening for water and particulates, including laboratory analyses. The applicant will define acceptance criteria for all in-scope components. The applicant currently performs many of these analyses informally and will formalize the analyses required prior to the period of extended operation. 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 lube and hydraulic oil

environments. The applicant samples the lubricating oil for most of the affected equipment on frequencies recommended by the vendor.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures and surveillances, and surveillances results. In addition, the team searched the applicant's corrective action database for relevant condition reports. The team also interviewed plant personnel and performed walk downs of the high-pressure coolant injection lube oil system.

For the Oil Analysis Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on carbon steel and gray cast iron internal pipe and component surfaces. With the enhancements to be incorporated prior to the period of extended operation, continued implementation of the Oil Analysis Program, if implemented as described, will appropriately manage the affects of aging during the period of extended operation.

.10 B.1.31 Periodic Surveillance & Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program is an existing plant-specific program that monitors structures, systems and components for degradation that required enhancements to resemble the program described in the GALL Report. This plant specific program closely resembled the program described in GALL Report, Section XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The team determined the GALL Report specified the use visual inspections while the applicant based this plant-specific program on inspections and testing that monitor various parameters such as system flow and pressure, surface conditions, loss of material, presence of corrosion and signs of cracking. The team found that this plant-specific program agreed with the GALL Report, Section XI.M38 recommendation to use a plant-specific program if that applicant could not perform visual inspections of the internal surfaces. The applicant will implement the enhancements prior to the period of extended operation and will base the evaluation frequency on the environmental factors.

The Periodic Surveillance and Preventive Maintenance Program include periodic inspections and tests that manage aging effects not managed by other aging management programs. The applicant identified enhancements to this program that altered existing preventive maintenance and added new activities, as reflected in Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report Non-Class 1 Mechanical," Revision 2, Attachment 2. For each activity that refers to a representative sample, a sample will be selected for each unique environment combination. The applicant specified they will use samples as determined by Electric Power Research Institute Report 107514, "Age Related Degradation Inspection Method and Demonstration," Chapter 4. The applicant planned to use this sampling plan to obtain 90 percent confidence that 90 percent of the population does not experience the age-related degradation.

The team reviewed license renewal program basis documents, aging management review documents, existing procedures and surveillances, and surveillances results. In

addition, the team searched the applicant's corrective action database for relevant condition reports. The team also interviewed plant personnel.

For the Periodic Surveillance and Preventive Maintenance Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on structures, systems and components subject to degradation in varying environments. With the enhancements to be incorporated prior to the period of extended operation, continued implementation of Periodic Surveillance and Preventive Maintenance Program, if implemented as described, will appropriately manage the affects of aging during the period of extended operation.

.11 B.1.32 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program is an existing program consistent with the GALL Report. This program manages the affects of aging by detecting cracks, loss of material, and coolant leakage by following the examination and inspection requirements specified in American Society of Mechanical Engineers, Section XI, Subsection IWB and approved American Society of Mechanical Engineers Code cases.

However; the applicant took an exception to the GALL Report recommendation to use Section XI, IWA-2210. Instead of meeting the specified distance and lighting requirements, the applicant specified they would use VT-2 examinations specified in Section XI, IWA-5000 to detect evidence of leakage on floor areas. The applicant (1) conducted ultrasonic tests the reactor head closure studs and volumetric tests on the reactor vessel flange threads; (2) visually examines the nuts, washers, and bushings; and (3) visually inspects the reactor vessel studs and flange exterior during hydrostatic pressure tests for leakage.

The team reviewed the license renewal application, the NRC aging management program audit, and any licensee responses to requests for additional information. The team used key words to identify any relevant condition reports in the corrective action database. In addition, the team reviewed completed inspection and examination data for potential adverse conditions affecting the studs. The team concluded that the licensee had effectively managed aging effects with this existing program. The team interviewed the program owner. The team verified that the applicant had approval to use visual (VT-1 and VT-2), surface, and ultrasonic tests for their 4th Inservice Inspection Interval by letter dated August 23, 2008.

For the Reactor Head Closure Studs Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects for the reactor vessel head studs during the period of extended operation.

.12 B.1.33 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program is an existing program that required two enhancements to be consistent with the GALL Report. The program manages reduction in fracture toughness of reactor vessel beltline materials because of neutron radiation embrittlement by periodically having hardness tests performed on samples removed from the core. The Reactor Vessel Surveillance Program uses existing Boiling Water Reactor Vessel Internals Program (BWRVIP) Integrated Surveillance Program capsules in plants, as well as the supplemental capsules of the Supplemental Surveillance Program, to provide data that bounds all operating plants. The applicant identified the following enhancements: (1) if the applicant removes their standby coupon without testing it, they must store the capsule so that it would be able to be used in the future, including during the period of extended operation, if necessary; and (2) implement the additional requirements specified in the final NRC safety evaluation for BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," prior to the period of extended operation.

The team reviewed license renewal application, the NRC aging management program audit, and licensee procedures. The team used key words to identify any relevant condition reports in the corrective action database. The team challenged the statement in Procedure 3.28.4, "Integrated Surveillance Program," Revision 8, in which the applicant specified that any correspondence from the site to the BWRVIP did not result in quality records even though BWRVIP products could affect Technical Specification changes. The team determined that the quality records included any information submitted to the NRC to justify a regulatory decision. Further, the team agreed that plant records related to regulated activities resulted in quality records. Consequently, the team concluded that the correspondence to the BWRVIP did not generate a quality record by itself. The team interviewed the program owner. The team determined the applicant follows many other BWRVIP programs that relate to the Integrated Surveillance Program.

For the Reactor Vessel Surveillance Program, the team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects for the reactor vessel head studs during the period of extended operation.

.13 B.1.36 Structures Monitoring Program

The Structures Monitoring Program is an existing program that required enhancements to be consistent with the GALL Report. The applicant indicated that the Structures Monitoring Program meets the requirements for the Maintenance Rule. The applicant identified acceptance criteria (e.g., cracking, spalling, splintering, corrosion, et cetera) from industry codes and standards related to the structure and structural commodity being evaluated. The applicant will continue to perform these structural inspections at the same frequency established for the Maintenance Rule program.

The licensee will implement the following enhancements to ensure consistency with the Gall Report: (1) clarify the scope to include items in the License Renewal Application, Section B.1.36; (2) specify commodities from Section B.1.36 to be added; (3) inspect inaccessible concrete when made accessible (i.e., following an excavation) and to inspect inaccessible areas whenever an adjacent accessible area has significant concrete degradation; (4) inspect elastomers (seals, gaskets and roof elastomers) to identify cracking and change in material properties; (5) perform engineering evaluations of groundwater samples to assess aggressiveness of groundwater on concrete monitor once every 5 years for pH, sulfates and chlorides; (6) visually examine wood for loss of material and change in material properties; (7) visually inspect the oil tank bunker crushed rock fill; and (8) clarify that condition reports are required to be written for structures being "acceptable with deficiencies" or "unacceptable."

The team reviewed the license renewal program basis documents, aging management review documents, and existing procedures. The team searched the corrective action database for relevant condition reports and evaluated the license use of industry information. The team interviewed personnel involved with performing the inspections. The team determined that the applicant had established an appropriate program, as specified in Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, and NUMARC 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2. To assess the effectiveness of the program the team performed a walk-down inspection of accessible areas of plant to compare the recorded results of the applicant's to the current condition of items, components, and structural systems. The team performed a walk down of the service water intake structure that included the ground level and the intake bay. The team determined that the applicant performed appropriate examinations during the visual inspections, and had made adequate assessments of the results.

From review of Procedure 0.27.1, "Periodic Structural Inspection of Structures," Revision 5, the team identified that the applicant did not include clear and concise acceptance criteria for use by different inspectors and/or at different periods in time with inspection frequencies of 5 or 10 years. In such cases, a clearly defined qualitative and quantitative acceptance criteria included in the inspection procedure assures consistency of observation and evaluation of any emerging trend. Furthermore, the program lacked a clear method of collating inspection data (e.g. matrix, spread sheet, graph) to readily identify any emerging adverse trend to assess and evaluate any aging effect. Following discussions with the team, the applicant initiated a procedure change to: (1) revise the implementing procedures to include clear, concise, and readily available acceptance criteria; and (2) develop a method to collate and display results of prior inspection in an effective manner to assess any emerging adverse trend due to aging in the material. Further, the applicant specified that they would commit to an enhancement to the structures monitoring program related to trending and evaluation of inspection results.

For the Structures Monitoring Program, the team concluded that the applicant had effectively implemented and performed appropriate evaluations of structures. Further, the applicant had considered pertinent industry experience and plant operating history to determine the effects of aging on plant structures and structural commodities. The team

concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

b.4 System Review

The applicant's license renewal application listed a number of plant systems within the scope of license renewal. From this list, the team selected the high-pressure coolant injection system for a focused review to determine whether the aging management programs would effectively manage aging effects related to this system. The aging effects requiring management for the high-pressure coolant injection system included cracking, cracking - fatigue, fouling, loss of material, loss of material – wear, and loss of preload. The applicant credited the following existing aging management programs for managing the identified aging effects: bolting integrity; buried piping and tanks inspection, external surfaces monitoring, flow-accelerated corrosion; oil analysis, periodic surveillance and preventive maintenance, and water chemistry control – boiling water reactor.

The team interviewed the high-pressure coolant injection system engineer, performed walk downs, and reviewed various documents to verify that the existing programs credited with managing the effects of aging on the high-pressure coolant injection system had been effective.

For the high-pressure coolant injection system, 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 aging effects on the high-pressure coolant injection system had been appropriately identified and addressed. Further, the team concluded that the applicant appropriately addressed the aging effects on the high-pressure coolant injection system within the applicable aging management programs.

c. Overall Conclusion

Overall 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 taken 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.

40A6 Meetings, Including Exit

The team presented the inspection results Mr. A. Zaremba, Director, Nuclear Safety Assurance, and other members of the applicant staff during an exit meeting conducted on August 14, 2009, and a supplemental exit meeting conducted on November 12, 2009. The applicant acknowledged the NRC inspection observations. The team returned all proprietary information reviewed during this inspection to the applicant.

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee Personnel

D. Bremer, License Renewal Project Manager
J. Damet, Predictive Maintenance Program Engineer
J. Ehlers, Electrical Systems Instrumentation and Control System Engineer
S. Freborg, License Renewal Engineering Liason
S. Gocek, Design Electrical Engineer
T. Hathaway, License Renewal Project Support Assistant
B. Keller, Mechanical Engineer
P. Leinenger, Flow Accelerated Corrosion Program Engineer
C. Long, Fire Protection System Engineer
J. Loynes, License Renewal Project Engineer
T. McClure, ISI/BWRVIP Program Engineer
M. Metzger, Diesel Generator System Engineer
L. Mitchell, Corrective Action and Assessments Performance Improvement Specialist
K. Newcomb, Station Fire Marshall
M. Stoner, Balance of Plant System Engineer
J. Sweeley, Civil Engineer
B. Victor, License Renewal Licensing Lead
R. Yantz, Civil Engineer Design

Entergy License Renewal Team Personnel

R. Ahrabli, Structural Lead
A. Cox, Technical Manager
D. Fronabarger, Technical Consultant
T. Ivy, Mechanical Supervisor
D. Lach, Project Manager
J. Lingenfelter, Technical Consultant
R. Rucker, Technical Consultant – Electrical

LIST OF ITEMS OPENED

Opened

05000298/2009010-01	URI	Adequacy of aging management for the torus (Section 4OA5.b.3.2)

DOCUMENTS REVIEWED

General

Engineering Reports (CNS-RPT-07-)

AMC04, "Aging Management Review of Bulk Commodities," Revision 2
AME01, "Aging Management Review of Electrical Systems," Revision 1
LRD05, "Operating Experience Review Report," Revision 2

Letters

NLS2008071, "License Renewal Application," dated September 24, 2008

NLS2009039, "Response to Request for Additional Information for License Renewal Application – Balance-of-Plant Scoping and Screening," dated May 28, 2009

NLS2009040, "Response to Request for Additional Information for License Renewal Application – Aging Management Programs," dated June 15, 2009

NLS2009049, "Response to Request for Additional Information for License Renewal Application – Safety RAI and Revised RAI," dated June 22, 2009

NLS2009055, "Response to Request for Additional Information for the License Renewal Application," dated July 29, 2009

NLS2009061, "Response to Request for Additional Information for the Review of the Cooper Nuclear Station License Renewal Application," dated August 13, 2009

NLS2009062, "Response to Request for Additional Information for the Review of Cooper Nuclear Station License Renewal Application," dated September 24, 2009

NLS2009063, "Response to Request for Additional Information for the License Renewal Application," dated August 17, 2009

Miscellaneous

Electric Power Research Institute Report 1003057, "Plant Support Engineering: License Renewal Electrical Handbook," Revision 1

Electric Power Research Institute Report 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," Revision 4

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

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

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

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

Scoping Documents

Drawings

104 license renewal system drawings submitted with application

2817-11, CA-6, "Non-critical Air Reactor Building," Revision 6, with as-built sketches S-3977, S-3978, and S-3982

X2850-224, SA-1, "Service Air Reactor Building," Revision 4

X2850-231, SA-1, "Service Air Reactor Building," Revision 3

Miscellaneous

Engineering Report CNS-RPT-07-LRD01, "System and Structure Scoping Results," Revision 2

Engineering Report CNS-LRG-02, "System and Structure Scoping (Project Guideline)," Revision 1

Engineering Report CNS-RPT-07-AMM20, "Aging Management Review of Nonsafety-related Systems and Components Affecting Safety-Related Systems," Revision 2

NEW AGING MANAGEMENT PROGRAMS

B.1.1 Above Ground Tanks

Condition Reports (CR-CNS-)

2003-07972	2004-05486	2009-02354	2009-04681	2009-07305

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report Non-Class 1 Mechanical," Revision 2, Section 3.1

Fire Water Storage Tank Inspection Results dated September 4, and 21, 2009

Work Orders 4703937 and 4715927 related to recoating of the fire water storage tanks

B.1.3 Buried Piping and Tanks Inspection

Condition Reports (CR-CNS-)

2004-05914	2006-06140	2006-06143	2009-01437

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 3.2

Listing of condition reports produced from a keyword search on "excavation"

LO-CNSLO-2006-00273, "Snapshot Assessment: Buried Piping, Tanks, and Structures," dated August 25, 2006

MPR Associates Report, "Evaluation of Buried Diesel Fuel Transfer Lines," dated September 20, 2004

Resolve Condition Report 2004-00577, Apparent Cause Evaluation – Buried Diesel Fuel Oil Piping

Second Ten-Year Interval Containment Inspection Program, Revision 1

B.1.22 Metal-Enclosed Bus Inspection Program

Condition Reports (CR-CNS-)

2000-01068	2001-04134	2003-02063	2003-02789	2004-01296
2005-03982	2005-04036	2007-00036	2007-01396	2008-09410
2009-03704	2009-03705	2009-03752	2009-03753	2009-03843

Drawings

LRA-E-001-SH01-0, "CNS Offsite Power Recovery Diagram," Revision 0
NB03097, "Bus Bolting Instructions for Electrical Connections," Revision 11

Miscellaneous

Aging Management Evaluation for the Metal Enclosed Bus Inspection Program

Engineering Report CNS-RPT-07-LRD09, "Aging Management Program Evaluation Results – Electrical," Revision 2, Section 3.1

Engineering Specification Change 90-332A, "Non-segregated Buses Insulation Replacement," dated February 11, 1992

Information Notice 89-64, "Electrical Bus Bar Failures"

Information Notice 98-36, "Inadequate or Poorly Controlled Non-safety Related Maintenance Activities Unnecessarily Challenged Safety Systems"

Information Notice 2000-14, "Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power"

Minor Modification Package 90-332C, "Start-up Transformer Non-Segregated Buses Insulation Replacement," dated November 16, 1995

Nebraska Public Power District Wooden Transmission and Distribution Pole Inspection and Treatment Procedure, Section G

Nonconformance Reports 88-168 and 88-169 related to arcing at a bolted connection

Problem Identification Report 2-17296 related to loose bus duct bolting

Procedure

7.3.41, "Inspection and Meggering of Non-Segregated Buses and Associated Equipment," Revisions 0 and 7

B.1.24 Non-Environmental Qualifications Bolted Cable Connections

Miscellaneous

Drawing NB03097, "Bus Bolting Instructions for Electrical Connections," Revision 11

Engineering Report CNS-RPT-07-LRD09, "Aging Management Program Evaluation Results – Electrical," Revision 2, Section 3.2

Nuclear Energy Institute NEI E6, "Electrical Connections Program White Paper," dated September 2006

Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02: Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," dated August 29, 2007

B.1.25 Non-Environmental Qualification Inaccessible Medium Voltage Cables

Condition Reports (CR-CNS-)

2009-03273 2009-05839 2009-05841 2009-05881

Drawings

3137, "Control Building Conduit Plan and Details below Elevation 882'6"," Revision 2
3190, "Underground Duct Banks Plan," Revision 5
3191, "Underground Duct Banks Plans, Sections and Details," Sheet 1, Revision 6
3192, "Underground Duct Banks Plans, Sections and Details," Sheet 2, Revision 3
3193, "Underground Duct Banks Sections and Details," Revision 4
4016, "Structural Electrical Manholes," Sheet 1, Revision 1
NC44587, "Routing of 12.5 kV Underground System," Revision 13

Miscellaneous

Engineering Report CNS-RPT-07-LRD09, "Aging Management Program Evaluation Results – Electrical," Revision 2, Section 3.3

Numerous photographs of the material condition of Cable Vaults P3, P4 and C3

Thermography Test Results

Procedures

2.3_S.1, "Panel S – Annunciator S-1," Revision 13

7.3.20, "4160 Volt Motor Insulation Testing (Except Reactor Recirculation Motors and MG Sets," Revision 10

Work Orders

4470716	4485664	4499479	4499481	4545601
4569070	4600817	4625764	4676361	4678641

B.1.27 Non-Environmental Qualification Insulated Cables and Connector

Condition Reports (CR-CNS-)

2001-04929	2001-05911	2002-02124	2005-01252	2007-01646
2007-02333	2008-02674	2008-03291	2008-03303	

Miscellaneous

Electric Power Research Institute Report TR-109619, "Guidelines for the Management of Adverse Localized Equipment Environments"

Engineering Report CNS-RPT-07-LRD09, "Aging Management Program Evaluation Results – Electrical," Revision 2, Section 3.5

NUREG/CR-5643, "Insights Gained from Aging Research," March 1992

B.1.29 One-Time Inspection Program

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 3.4

B.1.30 One-Time Inspection – Small Bore Piping

Miscellaneous

Engineering Report CNS-RPT-07- LRD02, "Aging Management Program Evaluation Report – Class 1 Mechanical," Revision 1, Section 3.1

American Society of Mechanical Engineers, Section XI, 2001 Edition, sections referenced in aging management program

Information Notice 97-46, "Unisolable Crack in High Pressure Injection Piping"

B.1.34 Selective Leaching

Procedures

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 3.5

B.1.37 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

Miscellaneous

Engineering Report CNS-RPT-07- LRD02, "Aging Management Program Evaluation Report – Class 1 Mechanical," Revision 1, Section 3.2

Generic Letter 88-01, "NRC Position on IGSCC [*Intergranular Stress Corrosion Cracking*] in Boiling Water Reactor Austenitic Stainless Steel Piping," dated January 25, 1988

NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," Revision 1

Safety Evaluation Related to Amendment No. 219 to Facility Operating License No. DPR-46, dated April 27, 2006

Safety Evaluation Related to Amendment No. 231 to Facility Operating License No. DPR-46, dated June 30, 2008

EXISTING PROGRAMS

B.1.2 Bolting Integrity

Condition Reports (CR-CNS-)

2003-01824	2004-02746	2005-02602	2005-02708	2005-06397
2006-08385	2009-05746	2009-05761	2009-05935	

Miscellaneous

American Society of Mechanical Engineers Section XI, Table IWB-2500-1

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.1

Electric Power Research Institute NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants - Volume 1" dated April 1988

Electric Power Research Institute Report TR-104213, "Bolted Joint Maintenance & Applications Guide," dated December 1995

NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," dated June 1990

System Engineer Desktop Guide, Section IV, "System Walk down 98-03-04," Revision 8

Visual Examination of Pressure Retaining Bolting (VT-1), "Main Run Pipe Flange to Valve Flange Bolting," dated October 28, 2006

Visual Examination of Pressure Retaining Bolting (VT-1), "Top Head Nozzle Flange to Pipe Flange Bolting," dated April 26, 2008

Procedures

0.30, "ASME Section XI Repair/Replacement and Temporary Non-Code Repair Procedure," Revision 23

3.28.1, "Inservice Inspection Program Implementation," Revision 11

3.28.1.1, "Visual VT-1 Examination of Pressure Retaining Bolting and Integral Attachments," Revision 7

3.28.1.6, "Visual Examination of Containment Bolting, VT-1," Revision 3

7.2.71, "Bolting Integrity and Torque Program," Revision 23

6.MISC.502, "ASME Class 1 System Leakage Test," Revision 29

6.1RHR.501, "ASME Section XI Periodic Pressure Test of the Class 2 Residual Heat Removal System Loop A," Revision 11

7-CNS-MA-121, "Fluid Leakage Management," Revision 2

Work Orders

4542591 4547519 4549506 4625525

B.1.10 Containment Inservice Inspection (IWE)

Calculation

NEDC 92-213, "ASME Section III, Subsection NE Evaluation of Torus Shell (Pitting)," Revision 2

Condition Reports (CR-CNS-)

2001-00522 2005-01188 2007-07398 2008-02650 2008-02770

Drawings

2520/4237, "Method of Concrete Pours – Lower Drywell," Revision 8
2520/4240, "Reactor Building Cross Section," Revision 12

Miscellaneous

Calibration history for FPC-FIS-61, -63, and -64 and six calibration work orders

Completed refueling operation procedures from November 2001, October 20006 and April 2008

Engineering Report CNS-RPT-07-LRD08, "Aging Management Program Evaluation Report – Civil/Structural," Revision 2, Section 3.2

Evaluation of Commitments Associated with Generic Letter 87-05, "Request for Additional Information-Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells," dated March 20, 2003

Generic Letter 87-05, "Request for Additional Information-Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells," dated March 12, 1987

Inservice Inspection Summary Report (to NRC), dated August 14, 2008

LO-CNSLO-2007-283, Snapshot Assessment on CNS First 10 Year Containment Inspection Program, 08/24/07 and associated corrective actions

Operating Experience Report Screening for Information Notice 97-10, "Liner Plate Corrosion in Concrete Containments"

Refueling Outage 19, 22, and 24 Reactor Torus Desludging, Inspection, and Coating Repair reports

Response to Generic Letter 87-05, "Request for Additional Information-Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells," dated May 12, 1987

TNC-ISI-07-008, "IWE Inspection Program Assessment," dated August 28, 2007

Ultrasonic Test Exam Data Sheet 304, "Thickness Measurements of Drywell Containment At Basement Floor Level," dated November 4, 1986

Procedures

2.1.20.3, "Reactor Vessel Refueling Preparations – Wet Lift," Revision 33

01-07384, "Underwater Visual Inspection of Coating and Containment Surfaces," Revision 1

B.1.11 Containment Leak Rate

Calculations

1998 Test – MASS POINT Calculations
Leak Rate Calculations
Leakage adjustments for Isolated Penetrations or Components
Time Calculations

Miscellaneous

Engineering Report CNS-RPT-07-LRD08, "Aging Management Program Evaluation Report – Civil/Structural," Revision 2, Section 3.1

NRC Letter; "Exemption From Appendix J to 10 CFR Part 50 To Allow Reverse Direction Local Leak Rate Testing of Four Containment Isolation Valves at Cooper Nuclear Station (TAC No. M89769)"

Primary Containment Leakage Rate Testing Program, Post Refueling Outage 24 Test Report

Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," Revision 0

Safety Evaluation by the Office of Nuclear Reactor Regulation, Amendment 38 to Facility Operating License DPR-46

Procedures

3.40, "Primary Containment Leakage Rate Testing Program," Revision 7
6.PC.501, "Primary Containment Local Leak Rate Tests," Revision 28
6.PC.504, "Primary Containment Leak Rate Test," Revisions 3 and 8

Program Basis Documents

License Amendments 224 and 226
Primary Containment Leakage Rate Testing Program Document, Revision 9
Technical Specifications, Section 5.5.12

B.1.12 Diesel Fuel Monitoring

Calculation

NEDC 97-012, "Emergency Diesel Generator Fuel On-site Storage Technical Specification Requirements," Revision 3

Condition Reports (CR-CNS-)

2002-03504	2003-01730	2005-07348	2006-04831	2006-05672
2006-07780	2007-06216	2007-06699	2007-08590	2008-07402
2008-09535	2008-09537	2009-03164		

Miscellaneous

Condition Report LO-CNS-WT-2006-00001, "Track Industry Progress of Ultra Low Sulfur Diesel Fuel Oil Testing and Future Impact on CNS EDG Engine Performance, dated November 20, 2006

Condition Report LO-CNS-LO-2009-00102, Information Notice 2009-02, "Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance," dated April 3, 2009

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.2

Report SIR-04-158, "American Petroleum Institute 570 Inspection Report – Diesel Fuel Oil Tank B," dated April 18, 2005

Report SIR-04-159, "American Petroleum Institute 570 Inspection Report – Diesel Fuel Oil Tank A," dated April 18, 2005

"White Paper on Use of Low Sulfur and Ultra Low Sulfur Diesel in Cooper-Bessemer Model KSV Emergency Diesel Generators," dated June 20, 2005

Procedures

2.2.12, "Diesel Fuel Oil Transfer System," Revision 47
8.7.1.30, "Particulate Contaminant Analysis for Diesel Fuel Oil," Revision 6
6.DG.601, "Diesel Fuel Oil Day Tank Particulate Contamination Test," Revision 10
6.DG.604, "Diesel Fuel Oil Storage Tank, Bunker A and B, Quality Test," Revision 15
6.DG.605, "Diesel Fuel Oil Incoming Truck Sampling," Revision 13
6.FP.103, "Diesel Fire Pump Inspection," Revision 10
6.FP.612, "Diesel Fire Pump Fuel Quality Test," Revision 6

Work Orders

700457417	700490667	700490667	700535145

B.1.14 External Surfaces Monitoring

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.3

Procedure 0.5 EVAL, "Preparation of Condition Reports," Revisions 18 and 19

System Engineering Walk-down Inspection Reports, dated

July 1, 2009	July 15, 2009	July 21, 2009	July 29, 2009

B.1.17 Fire Water System

Condition Reports (CR-CNS-)

2003-05986	2006-00551	2007-03008	2008-03971	2009-04757

Miscellaneous

Drawing 2016, "Fire Protection System Flow Diagram," Sheet 7, Revision 4

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.4.2

Evaluation A for Procedure 6.FP.611, "Fire protection tank internal painted surface 5 year examination," dated August 16, 2001

Procedure 6.FP.611 inspection results for the west tank, dated September 19, 2007

Procedure 6.FP.611 inspection results for the east tank, dated September 19, 2007

Procedure Change Request Number 48625, "Procedure Does Not Specify Hydrant Gasket Inspection," dated August 13, 2009

Procedures

2.2.30, "Fire Protection System," Revision 53
6.FP.301, "Operations Power Block Sprinkler System Testing," Revision 13
6.FP.602, "Engineers Fire Protection Examination," Revision 6
6.FP.603, "Fire Hose Station Examination," Revision 8
6.FP.608, "License Required Fire Fighting Equipment Monthly Examination," Revision 14
6.FP.610, "Yard Hydrant Flow Check And Fire Protection System Flow Test," Revision 12
6.FP.611, "Fire Protection Tank Internal Painted Surface 5 Year Examination," Revision 9

Work Orders

4276535	4332232	4338784	4361278	4374743
4429455	4457341	4485715	4501261	4526516
4542527	4542527	4604476	4636816	4637207
4637507	4637939	4660561	4676219	

B.1.18 Flow Accelerated Corrosion

Assessments

SA-02-033, Erosion/Corrosion Program Self-assessment Report, dated August 8, 2002
First Quarter 2009 Erosion/Corrosion Program Performance Assessment, dated April 6, 2009
Snapshot Assessment on CHECKWORKS, dated January 12, 2005
Snapshot Assessment on Erosion/Corrosion Program, dated January 2008

Condition Reports (CR-CNS-)

2005-01190 2005-01243 2005-05009 2006-07351 2008-03145

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.5

Program Basis Document PBD-EC, "Erosion/Corrosion Program Basis Document"

Report VM-1400.003, "Flow-Accelerated Corrosion Program Susceptibility Analysis," dated August 29, 1998

Response to IE Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," dated August 28, 1987

BS-E-7-EC93877SP-1A, "Ultrasonic Testing Measurement Data Sheet," dated April 23, 2008

Procedures

3.10, "Erosion/Corrosion Program," Revision 11

3.28.5, "Administrative Controls for Non-Destructive Examinations," Revision 0

8.3, "Control Parameters and Limits," Revision 55

8.3VIP, "Vessel Internals Protection Control Parameters and Limits," Revision 3

54-ISI-147-01, "Ultrasonic Test for Thickness Measurement Using Pulse-Echo Techniques," Revision 1

B.1.21 Masonry Wall

Miscellaneous

Engineering Report CNS-RPT-07-LRD08, "Aging Management Program Evaluation Report – Civil/Structural," Revision 2, Section 3.4

Procedures

0.27, "Maintenance Rule Program," Revision 18
0.27.1, "Periodic Structural Inspection of Structures," Revision 5

B.1.28 Oil Analysis

Condition Reports (CR-CNS-)

2007-00029	2007-00555	2007-02218	2007-02220	2007-02687
2007-03859	2007-05160			

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.7

Quarterly oil analysis reports from 2004 to 2008

Procedures

7.0.14, "Predictive Maintenance Program," Revision 4
7.0.14.2, "Lubrication/Oil Analysis Program," Revision 6

B.1.31 Periodic Surveillance and Preventive Maintenance

Condition Reports (CR-CNS-)

2005-01856	2007-01928	2008-00840

Miscellaneous

Engineering Report CNS-RPT-07-LRD07, "Aging Management Program Evaluation Report – Non-Class 1 Mechanical," Revision 2, Section 4.8

Procedures

7.0.2, "Preventative Maintenance Implementation," Revision 42

7.2.42, "Heat Exchanger Cleaning," Revision 25

7.2.53.1, "Diesel Generator Engine Mechanical Inspection," Revision 27

7.2.53.2, "Diesel Generator Turbocharger Maintenance," Revision 7

7.2.53.4, "Diesel Generator Starting Air Compressor Maintenance," Revision 6

7.2.62.1, "Stand-By Gas Treatment Trap 10 Maintenance," Revision 5

6.1SGT.501, "SGT A Carbon Sample, Carbon Adsorber, and HEPA Filter In-Place Leak Test, And Components Leak Test (Div 1)," Revision 10

6.HV.601, "Air Flow Test Of Fan Coil Unit FC-R-1G (HPCI)," Revision 6

6.PC.401, "Drywell And Torus Surfaces And Structural Elements Inspection," Revision 11

6.SC.502, "Secondary Containment Penetration Examination," Revision 13

Work Orders

4184934	4337307	4362766	4384604	4417946
4458581	4499533			

B.1.32 Reactor Head Closure Studs

Miscellaneous

American Society of Mechanical Engineers Section XI, Table IWB-2500-1

Engineering Report CNS-RPT-07- LRD02, "Aging Management Program Evaluation Report – Class 1 Mechanical," Revision 1, Section 4.9

Fourth 10-Year Inspection Interval, "IWB-2500-1 Examination Category: B-G-1, Pressure Retaining Bolting, Greater Than 2 inches in Diameter"

Maintenance Work Request 91-2954, "Reactor Vessel Head Stud's Replacement," dated January 8, 1992

Regulatory Guide 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," Revision 0

Procedures

7.4.4, "Reactor Pressure Vessel Head Removal," Revision 36
7.4.4.1, "Reactor Pressure Vessel Head Installation," Revision 24

B.1.33 Reactor Vessel Surveillance

Miscellaneous

BWRVIP-05, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," dated September 28, 1995

BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program Implementation for License Renewal," dated July 2003

Cooper Nuclear Station Vessel Internals Program, Revision 17

Engineering Report CNS-RPT-07- LRD02, "Aging Management Program Evaluation Report – Class 1 Mechanical," Revision 1, Section 4.10

Final Safety Evaluation of the BWR Vessel Internals Project BWRVIP-05 Report (TAC 93925), dated July 28, 1998

Generic Letter 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds," dated November 10, 1998

Information Notice 97-63, Supplement 1, "Status of NRC Staff's Review of BWRVIP-05"

Relief Request RI-29, Revision 1, American Society of Mechanical Engineers Section XI, related to nondestructive examination of reactor vessel circumferential welds

Title 10 Code of Federal Regulations, Part 50, Appendix G, "Fracture Toughness Requirements"

Title 10 Code of Federal Regulations, Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements"

Procedures

0-QA-01, "CNS Quality Assurance Program," Revision 11
0.4, "Procedure Change Process," Revision 47
3.4.7, "Design Change Calculation," Revision 30
3.28.4, "Integrated Surveillance Program," Revisions 7 and 8
7.4.9, "Surveillance Sample Specimen Holder Removal and Installation," Revision 12
9.RW.1, "Radioactive Shipments," Revision 21

B.1.36 Structures Monitoring

Calculations

NEDC 96-20, "Structural Inspections of CNS Structures," Revision 4

Condition Reports (CR-CNS-)

2009-03185 2009-03188 2009-03281

Miscellaneous

Engineering Report CNS-RPT-07-LRD08, "Aging Management Program Evaluation Report – Civil/Structural," Revision 2, Section 3.3

Structural Walk-down Inspection Reports from 1995, 1999, 2001, 2002, 2003, 2006 and 2007

Procedures

0.5.EVAL, "Preparation of Condition Reports," Revisions 18 and 19
0.5.CR, "Condition Report Initiation, Review and Classification," Revision 11
0.27, "Maintenance Rule Program," Revision 18
0.27.1, "Periodic Structural Inspection of Structures," Revision 5