UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BLVD
ARLINGTON, TEXAS 76011-4511

December 18, 2013

Mr. Oscar A. Limpias, Vice President-Nuclear
and Chief Nuclear Officer
Nebraska Public Power District
Cooper Nuclear Station
72676 648A Avenue
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION – NRC POST-APPROVAL LICENSE RENEWAL INSPECTION REPORT 05000298/2013008

Dear Mr. Limpias:

On November 7, 2013, U.S. Nuclear Regulatory Commission inspectors completed a Post-Approval Site Inspection for License Renewal at your Cooper Nuclear Station. The enclosed report documents the inspection findings, which were discussed on November 7, 2013, with Mr. Ken Higginbotham and other members of your staff.

The team reviewed selected procedures and records, observed activities, and interviewed personnel.

Based upon the results of this inspection, no findings of significance were identified.

In accordance with Title 10 of the *Code of Federal Regulations (*10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Geoffrey Miller, Chief
Engineering Branch 2
Division of Reactor Safety

Docket: 50-298
License: DPR-46

cc w/enclosure:
Attachment: Supplemental Information
Electronic Distribution for Cooper Nuclear Station

R:\ _REACTORS_CNS\2013\CNS 2013008 PRI-GAP **ML13352A313**

SUNSI Rev Compl.	■ Yes ☐ No	ADAMS	■ Yes ☐ No	Reviewer Initials	GAP
Publicly Avail	■ Yes ☐ No	Sensitive	☐ Yes ■ No	Sens. Type Initials	GAP

DRS/EB2	DRS/EB2	DRS/EB1	DRS/EB2	R1:DRS/EB1
GPick	JWatkins	MWilliams	BCorrell	MModes
/RA/	/RA/	/RA/	/RA/	/RA/
12/17/13	12/10/13	12/11/13	12/9/13	12/10/13
C:DRS/EB2	C:DRP/C	C:DRS/EB2		
GMiller	DAllen	GMiller		
/RA/	/RA/	/RA/		
12/13/2013	12/17/13	12/18/13		

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000298
License:	DPR-46
Report:	05000298/2013008
Applicant:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Ave Brownville, NE 68321
Dates:	October 21, to November 7, 2013
Inspectors:	G. Pick, Senior Reactor Inspector, Engineering Branch 2 M. Modes, Senior Reactor Inspector, Region 1 B. Correll, Reactor Inspector, Engineering Branch 2 M. Williams, Reactor Inspector, Engineering Branch 1 J. Watkins, Reactor Inspector, Engineering Branch 2
Approved By:	G. Miller, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000298/2013008; 10/21 – 11/07/2013; Cooper Nuclear Station, Post-Approval Site Inspection for License Renewal

The report covers an inspection conducted by regional inspectors in accordance with the NRC Manual Chapter 2515 and the NRC Inspection Procedure 71003.

The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after the NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

None

B. Licensee-Identified Violations

None

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA5 Other Activities Post-Approval Site Inspection for License Renewal (71003)

Phase 2 Inspection Activities

The team performed the Phase 2 Inspection activities prior to, and within 6 months of the period of extended operation. The period of extended operation is the additional 20 years beyond the original 40-year licensed term. The period of extended operation for Cooper Nuclear Station begins after midnight on January 18, 2014.

The team evaluated whether the licensee: (1) completed actions required to comply with the license renewal license condition and commitments; (2) implemented the aging management programs that agreed with those approved in the safety evaluation report and described in the updated safety analysis report; (3) followed the guidance in NEI 99-04, "Guidelines for Managing NRC Commitment Changes," for changing license renewal commitments and followed the guidance in 10 CFR 50.59 when making changes to the license renewal supplement; (4) identified, evaluated, and incorporated "newly identified" structures, systems, and components into their aging management programs; and (5) implemented operating experience review and corrective action programs that account for aging effects.

.01 Aging Management Programs with Associated Commitments

a. Inspection Scope

The team evaluated whether the licensee met the commitments and established aging management programs that effectively implemented activities to control the effects of aging. The team compared the commitments and aging management programs to the program descriptions in the updated safety analysis report supplement and in NUREG-1944, "Safety Evaluation Report (SER) Related to the License Renewal of Cooper Nuclear Station," and to the Generic Aging Lessons Learned (GALL) Report, Revisions 1 and 2, as appropriate.

The team reviewed supporting documents including implementing procedures, work orders, inspection reports, engineering evaluations, and condition reports; and visually inspected structures, systems, and components, as needed. The team evaluated whether the licensee completed the necessary actions to comply with the license conditions stipulated in the renewed facility operating license. The team interviewed the program owners for each program and other licensee personnel to evaluate whether the licensee completed the necessary actions to meet the commitments specified in the safety evaluation report.

NUREG-1944 and the updated safety analysis report supplement list the aging management programs and associated commitments made during the license renewal application process.

During this inspection, the team reviewed 36 of the 40 commitments and closed 32 commitments. The NRC had previously closed 4 commitments during the Phase 1

inspection documented in NRC Inspection Report 05000298/2012008 (ADAMS ML12342A390). The team did not close Commitments 29, 33, 34, and 35. The licensee created new Commitment 41 to track resolution of the amount of ferrite contained in the cast austenitic stainless steel main steam and reactor feedwater nozzles. The team reviewed 34 aging management programs.

Specific documents reviewed are listed in the report attachment.

b. Findings and Observations

1. B.1.1 Aboveground Steel Tanks Program and Commitment 1

The Aboveground Steel Tanks Program aging management program managed loss of material from external surfaces of outdoor, aboveground carbon steel tanks. The licensee performed periodic visual inspection of external surfaces and thickness measurement of locations inaccessible for external visual inspection. The licensee monitored Fire Water Storage Tanks A & B and Condensate Storage Tank 1A under this program.

The team interviewed the program owner and reviewed procedures, safety evaluation report, license renewal application, and updated safety analysis report. The team reviewed inspection records from 2007 and 2009 to evaluate the effectiveness of this aging management program, as well as verify that the licensee had established a baseline to evaluate any future degradation. The team determined that the licensee had removed the insulation from the fire water storage tanks and coated the exterior surface with a fiberglass foam insulation to prevent intrusion of moisture and ensure prevention of corrosion.

Commitment 1 specified:

> "Implement the Aboveground Steel Tanks Program. The thickness measurements will be performed at least once during the first 10 years of the period of extended operation and periodically thereafter. The results of the initial inspection will be used to determine the frequency of subsequent inspections."

The team verified that Procedure 3.13.2, "Above Ground Steel Tanks Program," Revision 1, specified that the licensee would perform bottom thickness measurement inspections for all of the tanks within the first 10 years after entering the period of extended operation. The team determined that the licensee had scheduled the inspection of the condensate storage tank for fall 2018 (Refueling Outage 30). Also, the licensee scheduled the inspections for the fire water storage tanks in 2024. The team determined Procedure 3.13.2 specified visual inspections of each of the tanks each operating cycle.

Based on review of the actions implemented related to the Aboveground Steel Tanks Program aging management program, the team concluded the licensee took appropriate actions to protect the tank exteriors and allow for easier inspection. The team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. Further, the team concluded that the licensee met the conditions of Commitment 1 prior to the period of extended operation.

2. B.1.2 Bolting Integrity Program and Commitment 2

The Bolting Integrity Program aging management program managed aging effects caused by loss of material, crack initiation, and loss of preload through periodic inspection of closure and structural bolting for indications of potential problems. The program implemented guidelines on materials selection, strength and hardness properties, installation procedures, lubricants and sealants; corrosion considerations in the selection and installation of pressure-retaining bolting, and enhanced inspection techniques.

The team reviewed the aging management program basis documents, implementing procedures, selected work orders, corrective actions documents, updated safety analysis report and safety evaluation report. The team interviewed the program owner to verify enhancements and program requirements had been met, including that the use of protective lubricants would not cause cracking of bolting. The team verified that personnel were familiar with the requirements of the bolting procedure.

Commitment 2 specified:

> "Enhance the Bolting Integrity Program to include guidance from EPRI (*Electric Power Research Institute*) NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," April 1988 and EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," December 1995, for material selection and testing, bolting preload control, inservice inspection, plant operation and maintenance, and evaluation of the structural integrity of bolted joints. Enhance the program to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC, to clarify the prohibition on use of lubricants containing MoS_2 for bolting at CNS, and to specify that proper gasket compression will be visually verified following assembly. Enhance the program to include guidance from EPRI NP-5769 and EPRI TR-104213 for replacement of non-Class 1 bolting and disposition of degraded structural bolting."

The team determined that Procedure 7.2.71, "Bolting and Torque Program," Revision 38:

- Included guidance related to material selection and testing, bolting preload control, inservice inspection, plant operation and maintenance, and evaluation of the structural integrity of bolted joints;

- Clarified that personnel should use the actual yield strength when selecting materials for low susceptibility to stress corrosion cracking, to prohibit the use of lubricants containing MoS_2 for bolting, and to specify that proper gasket compression would be visually verified following assembly; and

- Included guidance for replacement of non-Class 1 bolting and disposition of degraded structural bolting.

Based on review of the actions implemented related to the Bolting Integrity Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded that the licensee met the conditions of Commitment 2 prior to the period of extended operation.

3. B.1.3 Buried Piping and Tanks Inspection Program and Commitments 3, 36, 37, 38, 39, and 40

The Buried Piping and Tanks Inspection Program aging management program managed the effects of aging on buried piping, tanks, and valves through (1) preventive measures to mitigate corrosion and (2) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel and gray cast iron components. If trending within the corrective action program identified susceptible locations, the licensee evaluated areas with a history of corrosion problems to determine the need for additional inspection, alternate coating, or replacement. The team determined that the licensee identified the following systems as in-scope for license renewal: diesel generator fuel oil, standby gas treatment, high pressure coolant injection, service water, condensate makeup, and plant drains.

The team reviewed program documents, implementing procedures, license renewal documents, the updated safety analysis report, the safety evaluation report, plant modifications, and records. The team interviewed the program owner and reviewed excavation results, cathodic protection tests, corrective action documents, soil analysis evaluations, ultrasonic tests of in-scope buried pipes, and coating evaluations for the in-scope buried pipes.

The team determined that the licensee had: (1) upgraded and implemented a distributed bed cathodic protection system, (2) performed both local and guided wave ultrasonic tests on the excavated buried piping systems, (3) determined that they did not have corrosive soil, (4) established a buried piping program that risk-ranked all piping on site, and (5) included all the requirements of the license renewal safety evaluation report in their buried piping program.

Commitment 3 specified:

> "Implement the Buried Piping and Tanks Inspection Program."

The team determined that the licensee described this aging management program in Procedure 3.13.1, "Buried Piping and Tank Inspection Program Implementation," Revision 3. The licensee included portions of the program in Procedure 3-EN-C-343, "Underground Piping and Tanks Inspection and Monitoring Program," Revision 5C0 and Buried Piping and Tanks Program Basis Document, Revision 0. The team verified that the licensee had completed all of their actions required by this program prior to entering the period of extended operation.

Commitment 36 specified:

> "The Buried Piping and Tanks Inspection Program will include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The piping segments and tanks will be classified as having a high, medium or low impact of leakage based on items such as the safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on plant operation. The corrosion risk will be determined through consideration of items such as piping or tank material, soil resistivity, drainage, the presence of cathodic protection, and the type

of coating. During the period of extended operation, examinations of in-scope buried piping and tanks will be performed at a frequency of at least once every 10 years. Examinations of buried piping and tanks during the period of extended operation will consist of visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to perform an overall assessment of the condition of buried piping and tanks. The examinations will include visual inspection of at least eight feet of excavated piping on at least three high-risk in-scope systems, and will examine a minimum of 2 percent of the total linear feet of high-risk in-scope buried piping during each 10-year period."

The team verified that the licensee documented their initial risk assessment for all buried piping systems, including the in-scope license renewal systems in Report 1000098, "Site Specific Risk Report: Cooper Nuclear Station," dated December 22, 2010. The team verified that the risk ranking: (1) included consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion; (2) classified piping segments and tanks as having a high, medium or low impact of leakage based on items such as the safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on plant operation; (3) included items such as piping or tank material, soil resistivity, drainage, cathodic protection, and coatings to establish the corrosion risk. The team verified that the licensee performed a study to determine soil resistivity, as documented in Report 1100302.401, "Soil Corrosivity Analysis and Engineering Assessment of Effects on Buried Piping," dated December 4, 2012.

The team verified that Procedure 3.13.1 required: (1) examinations of in-scope buried piping and tanks would be performed at least once every 10 years; (2) visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to assess the condition of buried piping and tanks; (3) examinations of at least eight feet of excavated piping on at least three high-risk in-scope systems; and (4) examination of a minimum of 2 percent of the total linear feet of high-risk in-scope buried piping during each 10-year period.

During discussions, the licensee indicated that they would inspect at least eight feet of three of their highest risk-ranked buried piping systems every 10-year period. The team determined this was an appropriate way to evaluate and manage the aging effects on buried piping since they did not have any high-risk in-scope buried pipe systems. The licensee agreed to include this guidance in Procedure 3.13.1 to ensure that at least eight feet of three of the <u>highest</u> in-scope risk-ranked piping systems would be excavated and evaluated. The license initiated LO-2011-00258-084 to track this change.

Commitment 37 specified:

"Prior to the period of extended operation, NPPD will inspect buried piping and tanks in six systems. These systems are diesel generator fuel oil (DGFO), standby gas treatment, high pressure coolant injection (HPCI), service water (SW), condensate makeup (CM), and plant drains. Direct or opportunistic visual inspections of excavated piping will be performed for DGFO, standby gas treatment, plant drains, SW, and CM systems. NPPD will use a non-visual examination method for the emergency condensate storage tank supply to HPCI piping due to its lack of ready access for excavation. In addition, non-visual examination methods may be employed for buried piping in other systems where the piping configuration allows for effective assessment via such methods. The total linear feet of piping inspected

using all of the methods discussed above will be a minimum of 2 percent of all high-risk in-scope buried piping."

The team reviewed the inspection results for the in-scope systems in Report 1104551.407, "Summary of 2013 Direct Examinations at Cooper Nuclear Station," dated October 7, 2013, and Report 1200599.402, "ILI Inspection of High Pressure Coolant Injection Suction Line 18" HP-5 at Cooper Nuclear Station," dated December 7, 2012. The team verified that the licensee inspected the diesel generator fuel oil, standby gas treatment, high pressure coolant injection, condensate makeup supply, service water and plant drains prior to entering the period of extended operation. The licensee performed the high pressure coolant injection line inspection with a robot from the interior of the piping. The licensee inspected a minimum of eight feet of piping in each of the systems, performed visual inspections of the exterior of each piping segment excavated, used guided wave technology where excavated, and evaluated then repaired the piping system coatings.

Commitment 38 specified:

> "Irrespective of risk ranking, NPPD will inspect at least one segment of buried piping in each of three in-scope systems, service water, fire protection, and condensate makeup."

The team verified that the licensee inspected the service water, fire protection and condensate makeup systems. The licensee documented the fire protection system inspection in Inspection Checklist 10-04-2011 and the service water and condensate makeup inspections in Report 1104551.407.

Commitment 39 specified:

> "NPPD will upgrade the site cathodic protection system prior to the period of extended operation for in-scope piping and buried tanks."

The team verified that the licensee upgraded their cathodic protection system prior to entering the period of extended operation. The team reviewed the modifications for the upgraded components and reviewed the protection provided by the newly installed cathodic protection system. The team determined that the licensee provided sufficient protection for the in-scope buried piping systems. The licensee indicated that they expected to make additional voltage adjustments to their cathodic protection system during the next annual survey.

Commitment 40 specified:

> "The Buried Piping and Tanks Inspection Program will be revised to ensure that, during the period of extended operation, the cathodic protection system will be maintained and annually tested in accordance with NACE (National Association of Corrosion Engineers) standards RP0285-2002, '*Corrosion Control of Underground Storage Tank Systems by Cathodic Protection,'* and SP0169-2007, *'Control of External Corrosion on Underground or Submerged Metallic Piping Systems,'* with a minimum system availability of 90 percent. If 90 percent availability is not maintained, the condition will be entered into the corrective action program to evaluate the impact and effect corrective action."

The team determined that the licensee established weekly rectifier channel checks by operations and fire protection personnel. The licensee specified in Procedure 3.13.1 that they would maintain 90 percent availability on a 12-month rolling average and would initiate a condition report whenever 90 percent availability is not maintained. Although Procedure 3.13.1 specified periodic tests of the rectifiers to meet the criteria in NACE SP0169-2007, the team verified that the licensee established a periodic task to test the system annually.

Based on review of the actions implemented related to the Buried Piping and Tanks Inspection Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded that the licensee met the conditions of Commitments 3, 36, 37, 38, 39, and 40 prior to the period of extended operation.

4. B.1.10 Containment Inservice Inspection Program and Commitments 5, 33, 34, and 35

The Containment Inservice Inspection Program aging management program managed loss of material and cracking for the primary containment and its integral attachments. The program used the ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition, through the 2003 Addenda. Visual inspections monitored for loss of material from the steel containment shells and their integral attachments; containment hatches and airlocks; moisture barriers; and pressure retaining bolting. The licensee inspected surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

The team reviewed the updated safety analysis report, the aging management program evaluation report, procedures, program documents, and the safety evaluation report. The team interviewed the program owner and reviewed inspection records.

Commitment 5 specified:

> "Enhance the Containment Inservice Inspection Program to add examination of required accessible areas using a visual examination method and surface areas not accessible on the side requiring augmented examination to be examined using an ultrasonic thickness measurement method in accordance with IWE-2500(b). Enhance the program to document material loss in a local area exceeding 10 percent of the nominal containment wall thickness or material loss in a local area projected to exceed 10 percent of the nominal containment wall thickness before the next examination in accordance with IWE-3511.3 for volumetric inspections. To ensure the [drywell sand cushion drain] lines are obstruction free, a vacuum test of all eight sand bed drain lines will be performed prior to the period of extended operation."

The team verified that the licensee revised the Fourth 10-Year Interval Containment Inspection Program, Section 3.2.5, to (1) require augmented ultrasonic thickness measurements from the accessible portion of the component for an area that was inaccessible and (2) incorporate the requirement to conduct ultrasonic testing when it was predicted to exceed or exceeded 10 percent nominal wall thickness for material loss. The team verified that the licensee conducted Procedure SP11-002, "Drywell Sand Cushion Drain Vacuum Test," on June 11, 2012, which demonstrated that all eight sand bed lines remained free of obstructions and did not contain any water.

Commitment 33 specified:

> "NPPD will recoat the wetted portion of the CNS torus within 3 years after entering the period of extended operation."

The team discussed this commitment with the program owner and responsible managers. The team verified that the licensee continued to carry this as a budgeted item for implementation in 2016 during Refueling Outage 29. The licensee indicated that they would evaluate their available options related to managing the effects of aging of the submerged portions of the torus (pressure suppression chamber) following the upcoming inspections. The team determined from discussions with the program owner and from review of inspection reports that the corrosion rate had remained relatively constant between 2-5 mils per year. The licensee attributed this to the inerted atmosphere decreasing the amount of available oxygen for generating corrosion products, the reduced conductivity because of the reduced amount of particulates, and removal of the corrosion products that reduced the ability of particulates to create concentration cells.

Commitment 34 specified:

> "NPPD will remove sludge and inspect the wetted portion of the torus every refueling outage from now until the torus is recoated."

The team reviewed inspection reports NUC2010117, "Refueling Outage RE26 Reactor Torus Filtration and Desludging, IWE Examination, Coating and Corrosion Inspection Coating Repair," Revision 0, and NUC2012108, "Refueling Outage RE27 Reactor Torus Filtration and Desludging, IWE Examination, Coating and Corrosion Inspection Coating Repair," Revision 0. The team verified that the licensee removed sludge and corrosion products prior to inspecting the torus during the last two outages. The team determined that the licensee identified no pits that exceeded the reporting threshold in 2011 and identified two pits that exceeded the reporting threshold in 2012. The team determined that the licensee had identified a decreased number of pits exceeding the thresholds since they began desludging and cleaning the torus each outage. The licensee planned the next inspection in the fall 2014. The team verified that the licensee tracked future sludge removal activities with LO 2010-0259-005 and LO 2010-0259-006.

Commitment 35 specified:

> "NPPD will complete an analysis following each torus inspection that demonstrates that the projected pitting of the torus up to the time that the torus is recoated, will not result in reduction of torus wall thickness below minimum acceptable values."

The licensee performed Calculation NEDC 94-214, "Evaluation of Torus Shell Corrosion and the Impact to Structural Integrity of the Torus," Revision 6, following Refueling Outage 26. Calculation NEDC 94-214 utilized actual measurements from Bay 6 and Bay 9 control areas to estimate the representative corrosion rates of the torus. The calculation determined that the torus corroded between 1-2 mils per year since the previous inspection in 2011. To estimate the amount of time available before exceeding any minimum thickness values, the licensee scaled up the corrosion rate by a factor of 2.5 and used 5 mils per year. The licensee further determined that they could have up

to 8 mils per year corrosion and still monitor/inspect the torus every 2 years through 2020. Since the calculation used an end point of 2020, the team recommended that the licensee revise the calculation to consider the entire 20-year period of the period of extended operation.

License Condition 2.F specified, "The USAR supplement, as revised, describes certain future activities to be completed prior to and/or during the period of extended operation. The licensee shall complete these activities in accordance with Appendix A of NUREG-1944, 'Safety Evaluation Report Related to the License Renewal of Cooper Nuclear Station,' dated October 2010, as supplemented by letters from the licensee to the NRC dated November 15 and 18, 2010. The licensee shall notify the NRC in writing when implementation of these activities is complete and can be verified by the NRC inspection."

The team determined that the licensee had not updated Calculation NEDC 94-214 following Refueling Outage 27. The team identified the failure to perform Calculation NEDC 94-214, as required by Commitment 35, as a performance deficiency for failure to meet the conditions of License Condition 2.F. Subsequently, the licensee completed Calculation NEDC 94-214, Revision 7, for the data collected during Refueling Outage 27 that demonstrated the corrosion rate remained linear at approximately 2 mils per year. The team screened this performance deficiency using Manual Chapter 0612, Appendix B and concluded it was of minor safety significance. The licensee entered this into their corrective action program as Condition Report 2013-07566. The licensee added clarification to LO-2010-00259 that required them to update the corrosion analysis in Calculation NEDC 94-214 following every refueling outage until the licensee recoated the torus.

By using a conservative corrosion rate of 8 mils per year, the licensee determined that the torus recoat could wait until the 2018 refueling outage. The team verified that the licensee tracked future calculations of corrosion rate with LO 2010-0259-009 and LO 2010-0259-010.

Based on review of the actions implemented related to the Containment Inservice Inspection Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation for those portions of the program related to Commitment 5. The team concluded that the licensee met the conditions of Commitment 5 prior to the period of extended operation.

The team updated the status for Commitments 33, 34, and 35. These commitments could not be closed since the licensee continued to implement the requirements and the commitments had a due date of January 18, 2017. Consequently, these commitments and this portion of the program will be reviewed during a future inspection.

5. <u>B.1.12 Diesel Fuel Monitoring Program and Commitment 6</u>

The Diesel Fuel Monitoring Program aging management program managed the effects of aging caused by loss of material and corrosion. The program used fuel sampling to ensure that the licensee maintained adequate diesel fuel quality to prevent loss of material in fuel systems. The licensee minimized the exposure to fuel oil contaminants such as water and microbiological organisms through periodic sampling and analysis,

draining and cleaning of tanks, and verifying new fuel oil quality before placing the fuel into the storage tanks. The licensee performed the sampling and analysis in accordance with technical specifications for fuel oil purity and the guidelines of ASTM Standards D4057, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," and D975, "Standard Specification for Diesel Fuel Oils."

The team reviewed the license renewal application, safety evaluation report, updated safety analysis report, reviewed the commitments implementation review document, procedures, work instructions, and interviewed the program owner. The team determined that Engineering Evaluation 11-037, "Diesel Fuel Oil Tank Erosion Rate Assessment," Revision 0, demonstrated that the diesel fuel oil tanks erosion rate remained acceptable. The team determined that the minimum wall thicknesses for each tank exceeded the minimum allowable wall thickness and concluded the 20-year inspection interval remained acceptable because of the low rate of erosion. Also, the team confirmed during a walk down of the emergency diesel generators and the diesel fire pump fuel oil tank that the tanks remained in good material condition externally.

Commitment 6 specified:

> "Enhance the Diesel Fuel Monitoring Program to include the use of ASTM Standard D4057 for sampling of the diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to include periodic visual inspections and cleaning of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. Enhance the program to include periodic multilevel sampling of the diesel fuel oil day tanks and the diesel fire pump fuel oil storage tank and to include periodic visual inspections as well as ultrasonic bottom surface thickness measurement of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. Enhance the program to provide the acceptance criterion of < 10 mg/l for the determination of particulates in the diesel fire pump fuel oil storage tank. Enhance the program to specify acceptance criterion for UT thickness measurements of the bottom surfaces of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. The acceptance criteria for UT measurement of tank bottom thickness for the referenced diesel fuel tanks will be based on component as-built information adjusted for corrosion allowance. If measurements show less than the minimum nominal thickness less corrosion allowance, engineering will evaluate the measured thickness for acceptability under the corrective action program. Evaluation will include consideration of potential future corrosion to ensure that future inspections are scheduled before wall thickness becomes unacceptable."

The team verified that:

- Procedure 6.FP.612, "Diesel Fire Pump Fuel Quality Test," Revision 10, incorporated the guidance contained in ASTM Standard D4057 when sampling the diesel fire pump fuel oil storage tank.

- The licensee had initiated preventative maintenance tasks that required inspection and cleaning of the diesel fuel oil storage tanks, diesel fuel oil day tanks, and diesel fire pump fuel oil storage tank. Further, Procedure 7.0.4, "Conduct of Maintenance," Revision 37, required maintenance technicians to visually examine internal surfaces for the effects of aging whenever any system

or component boundary was breached. Procedure 7.0.4 specified that maintenance technicians complete aging management training (MNT206-00-00).

- Procedure 6.DG.601, "Diesel Fuel Oil Day Tank Particulate Contamination Test," Revision 16, required quarterly multilevel sampling of the diesel fuel oil day tanks, and Procedure 6.FP.612, "Diesel Fire Pump Fuel Quality Test," Revision 10, required representative bottom sampling of the diesel fire pump fuel oil storage tank.

- Procedure 6.DG.601 incorporated acceptance criteria of less than or equal to 10 mg/L for the diesel fire pump fuel oil storage tank.

- Maintenance Plans 800000033983, "Perform Tank Examinations," and 800000008796, "Clean Fuel Oil Storage Tanks," established acceptance criteria for ultrasonic testing thickness measurements for bottom surfaces of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump. The team confirmed that the licensee established the acceptance criteria based on the as-built wall thicknesses adjusted for a corrosion allowance. Procedure 7.0.4 directed that personnel implement corrective actions if measurements show less than the minimum nominal thickness, less the corrosion allowance, for engineering to evaluate the measured thickness for acceptability under the corrective action program. The evaluation addressed potential future corrosion to ensure that future inspections were scheduled before wall thickness becomes unacceptable.

Based on review of the actions implemented related to the Diesel Fuel Monitoring Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded that the licensee met the conditions of Commitment 6 prior to the period of extended operation.

6. <u>B.1.14 External Surfaces Monitoring Program and Commitment 7</u>

The External Surfaces Monitoring Program aging management program monitored for loss of material from external surfaces of systems and components. The licensee credited the program with managing loss of material from internal surfaces for situations in which internal and external material and environment combinations represented the internal surface condition. The licensee inspected normally inaccessible surfaces during refueling outages and inspected insulated surfaces whenever they exposed the external surface. The licensee established inspection frequencies to manage aging effects on applicable components and ensure the components would perform their intended function during the period of extended operation.

The team reviewed license renewal program basis documents, aging management review documents, implementing procedures, walk down checklists, updated safety analysis report, and safety evaluation report. The team interviewed the program owners, reviewed licensee use of industry information, and reviewed walk down records. During the interviews, the team determined that the licensee had established a comprehensive program and provided appropriate training and guidance documents to the system engineers.

The team determined the licensee completed external surface inspections prior to the period of extended operation as part of routine system engineer walk downs. System engineers had inspected the external surfaces of structures, systems, and components regardless of the material. The team verified that the licensee included the review of structural elements separately within the Structures Monitoring Program.

Commitment 7 specified:

> "Enhance the External Surfaces Monitoring Program to clarify that periodic inspections of systems in-scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3) will be performed. Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in-scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2)."

The team determined that Procedure EN-DC-178, "System Walkdowns," Revision 4C0, (1) required walk downs to include inspections of areas surrounding safety-related systems to identify hazards to those systems and inspections of nearby systems that could impact safety-related systems including nonsafety-related structures, systems, and components that were in scope and subject to aging management review and (2) required system engineer monthly walk downs for Category 1 (maintenance rule or power production) and at least quarterly for Category 2 (all other in-scope systems). Desktop Guide 98-03-08, "Systems in Scope," listed the in-scope license renewal systems by Category 1 or 2 and defined the categories, specified that system engineers focus on those aspects of system material condition and operations that might not be noted during routine operations and maintenance, and used the EPRI Aging Assessment Field Guide to aid in identifying age-related degradation.

The team verified that Procedure 7.0.13, "Control of Insulation Removal and Installation," Revision 17, included guidance to mechanics to inspect for aging effects such as loss of material and corrosion when they remove insulation and added a form to document the evaluation.

Based on review of the actions implemented related to the External Surfaces Monitoring Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded that the licensee met the conditions of Commitment 7 prior to the period of extended operation.

7. <u>B.1.15 Fatigue Monitoring Program and Commitment 8</u>

The Fatigue Monitoring Program aging management program tracked the number of critical thermal and pressure transients for selected reactor coolant system components, in order not to exceed design limits on fatigue usage. The program ensured the validity of analyses that explicitly assumed a fixed number of thermal and pressure transients by assuring that the actual effective number of transients does not exceed the assumed limit. This program also addressed the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant.

The team reviewed the license renewal application, safety evaluation report, updated safety analysis report, program basis document, procedures, work instructions, and corrective action documents. The team interviewed the program owner and reviewed inspection records.

The team determined that Procedure 3.20, "Reactor Pressure Vessel and Torus Thermal Transient Review," Revision 19, required (1) collection of data following reactor pressure vessel operational transients, (2) performed a periodic review of operational transients for trending the effect on fatigue usage as noted in the updated safety analysis for the reactor pressure vessel, and (3) tracks operational transients for the effect on fatigue usage for the Torus.

Commitment 8 specified:

> "Consideration of the effect of the reactor water environment will be accomplished through implementation of one or more of the following options for the reactor vessel shell and lower head, feedwater nozzles, core spray nozzles and RHR pipe transition.
>
> 1) Update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs (cumulative usage factors) less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined using the NRC-approved version of the ASME code or the NRC-approved alternative (e.g., NRC-approved code case). NPPD will use NUREG/CR-6909 when determining the effects of the reactor coolant environment on the fatigue life of Alloy 600 components.
>
> 2) Repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0.
>
> The CNS Fatigue Monitoring Program will be enhanced to require the recording of each transient associated with the actuation of a safety/relief valve."

In the NRC Inspection Report 05000298/2012008, dated December 6, 2012 (ML12342A390), the inspectors determined that Procedure 3.20, Revision 18, did not incorporate environmental factors and implement the methodology described in Engineering Evaluation 10-023, "Reactor Pressure Boundary Components Fatigue Management Plan." During this inspection, the team verified that the licensee had incorporated using environmental factors for determining the cumulative usage factor and determined that the procedure implemented the methodology described in Engineering Evaluation 10-023.

Based on review of the actions implemented related to the Fatigue Monitoring Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded that the licensee met the conditions of Commitment 8 prior to the period of extended operation.

8. B.1.16 Fire Protection Program and Commitment 9

The Fire Protection Program aging management program managed the effects of aging through visual inspection of fire barriers, including periodic functional tests of fire rated doors, inspection and testing of fire suppression systems, and inspections during testing of the diesel driven fire pump. The fire barriers included the following components fire barrier penetration seals, fire dampers, fire stops, fire wraps, fire barrier walls, ceilings, floors, and fire doors. The fire suppression systems included Halon and CO_2.

The team reviewed license renewal program basis documents, aging management review documents, maintenance plans, procedures, updated safety analysis report, and safety evaluation report. The team interviewed the program owner, reviewed inspection and test records, and reviewed relevant condition reports.

Commitment 9 specified:

> "Enhance the Fire Protection Program to explicitly state that the diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the engine is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running, such as excessive fuel oil, lube oil, or exhaust gas leakage. Enhance the program to specify that diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking at least once every 5 years. Enhance the program to require visual inspections of fire damper framing to check for signs of degradation. Enhance the program to require visual inspections of the Halon and CO_2 fire suppression systems at least once every six months to check for signs of degradation in a manner suitable for trending. Enhance the program to include inspection of Cardox hose reels for corrosion. Acceptance criteria will be enhanced to verify no unacceptable corrosion. Enhance the program to require visual inspection of concrete flood curbs, manways, hatches, and hatch covers on an 18-month basis to check for signs of degradation."

The team determined that:

- Procedure 6.FP.103, "Diesel Fire Pump Inspection," Revision 17, required: (1) visual inspection of the diesel fire pump engine sub-systems, including inspection of the fuel supply line, while the engine was running to verify no fuel oil, lube oil, or exhaust gas leakage and (2) internal visual inspection every 5 years of the diesel fire pump engine carbon steel exhaust components for evidence of corrosion or cracking.

- Procedure 6.FP.203, "Fire Damper Assembly Examination," Revision 10, required visually inspecting fire damper framing to check for signs of degradation and established the frequency of the inspection.

- Maintenance Plan 800000041151 specified visual inspection every 6 months of the portions of the Halon and CO_2 systems that were accessible at power and Maintenance Plan 800000041152 specified visual inspection every 24 months for those portions of the systems not accessible because of radiological conditions.

- Maintenance Plan 800000003836 required visual inspection of the Cardox hose reels for corrosion.

- Maintenance Plan 800000041381 specified visual inspection every 18 months of the concrete flood curbs, manways, hatches, and hatch covers.

The team verified that the licensee had performed each of these enhanced inspections prior to entering the period of extended operation.

Based on review of the actions implemented related to the Fire Protection Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team determined that the licensee met the conditions of Commitment 9 prior to the period of extended operation.

9. B.1.17 Fire Water System Program and Commitment 10

The Fire Water System Program aging management program managed the effects of aging caused by loss of material and corrosion. The licensee performed periodic testing, flushing, nondestructive examination, leakage detection and volumetric examinations.

The team reviewed license renewal program basis documents, aging management review documents, maintenance plans, procedures, the updated safety analysis report, and the safety evaluation report. The team interviewed the program owner, reviewed work records, and reviewed relevant corrective action documents.

Commitment 10 specified:

> "Enhance the Fire Water System Program to include inspection of hose reels for corrosion. Acceptance criteria will be enhanced to verify no unacceptable corrosion. Enhance the program to include visual inspection of spray and sprinkler system internals for evidence of corrosion. Acceptance criteria will be enhanced to verify no unacceptable corrosion. Enhance the program to provide wall thickness evaluations of fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the program to add that a sample of sprinkler heads required for 10 CFR 50.48 will be tested or replaced using guidance of NFPA-25 (2002 edition), Section 5.3.1.1.1, before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation."

The team verified that:

- Procedure 6.FP.603, "Fire Hose Station Annual Examination," Revision 10, required inspecting hose reels for corrosion and specified no unacceptable corrosion allowed. The licensee established separate maintenance plans to inspect the hose reels for accessible areas and high radiation areas.

- Procedure 6.FP.302, “Automatic Deluge and Pre-Action Systems Testing,” Revision 24, required inspecting for corrosion when opening deluge valves and specified no unacceptable corrosion allowed. The licensee identified no corrosion when they replaced the deluge valves around transformers in 2012.

- Repetitive Task 800000041971 required ultrasonic testing of fire protection piping to determine wall thickness of the piping. The licensee measured the wall thickness in four pipe lines (i.e., 2.5-, 3-, 4-, and 12-inch). The licensee concluded that the lines had expected service lives that exceed the period of extended operation.

- The licensee elected to replace rather than perform sample testing of their sprinkler heads. The licensee identified they would replace 976 sprinkler heads in eleven fire water lines beginning in 2023 to prevent exceeding their 50-year service life. The licensee created maintenance plans for each line and highlighted the lines on fire protection drawings.

The team verified that the licensee had trained maintenance personnel to recognize corrosion and other forms of age-related degradation during visual inspections. Procedure 7.0.4 required maintenance personnel to initiate corrective action documents if they identified aging effects such as loss of material or corrosion and required visual examination of internal surfaces for the effects of aging whenever they breached any system or component boundary.

Based on review of the actions implemented related to the Fire Water System Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team determined that the licensee met the conditions of Commitment 10 prior to the period of extended operation.

10. <u>B.1.18 Flow-Accelerated Corrosion Program and Commitment 11</u>

The Flow-Accelerated Corrosion Program aging management program managed the loss of material in safety-related and nonsafety-related carbon steel components and gray cast iron in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid. The licensee based their program on the EPRI recommendations in NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” The program (1) identified critical locations, (2) determined the extent of thinning at the critical locations, and (3) required follow-up inspections to confirm predictions, or repair or replace components as necessary.

The team reviewed implementing procedures, program documents, the updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed flow-accelerated corrosion records for several identified piping locations. The team determined that the program owner effectively monitored and tracked susceptible locations to prevent failures of susceptible piping configurations.

Commitment 11 specified:

> “Enhance the Flow-Accelerated Corrosion Program to update the System Susceptibility Analysis for this program to reflect the lessons learned and new

technology that became available after the publication of NSAC-202L Revision 1. Program guidance documents will be revised to stipulate requirements for training and qualification of non-CNS personnel involved in implementing the FAC program."

The team verified the program owner implemented the elements of NSAC-202L-R2 and followed the EPRI guidelines for predicting, detecting, and monitoring flow-accelerated corrosion in plant piping and other components by conducting analysis to determine critical locations, performing baseline inspections, and repairing or replacing components as necessary. The team verified that Procedure 3.10, "Flow Accelerated Corroston (FAC) and Microbiologically Influenced Corrosion (MIC) Program Implementation," Revision 13, stipulated training and qualification requirements for non-licensee personnel if they performed activities required by the flow-accelerated corrosion program.

Based on review of the actions implemented related to the Flow-Accelerated Corrosion Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 11 prior to the period of extended operation.

11. B.1.20 Inservice Inspection – IWF Program and Commitments 12 and 30

The Inservice Inspection – IWF Program aging management program managed loss of material for ASME Class 1, 2, 3 and MC piping, component supports, bolting, and base plates. Visual inspections looked for evidence of corrosion; deformation; misalignment; improper clearances; improper spring settings; damage to close tolerance machined or sliding surfaces; and missing, detached, or loosened support items that might compromise support function or load capacity.

The team reviewed license renewal documents, program documents, implementing procedures, updated safety analysis report, and safety evaluation report. From interviews with the program owner, the team determined that the licensee had established a program as described in the NRC safety evaluation report and the updated safety analysis report supplement.

Commitment 12 specified:

"Enhance the Inservice Inspection - IWF Program to include Class MC piping and component supports. Enhance the program to clarify that the successive inspection requirements of IWF-2420 and the additional examination requirements of IWF-2430 will be applied."

The team determined that the licensee added an additional 128 IWF supports within the scope of license renewal. The licensee grouped the components based on similar function and conditions as allowed by Table IWF-2500-1, "Examination Categories," Note 3. The team confirmed that the licensee classified the components into six groups. The licensee selected the following components for examination in the 5th and 6th inservice inspection intervals: B7-VH-S6, B12-DCPRB-S28, SC-EQT-S0, SC-SAD-S1, B12-DCPR-S28, and NRV24-S5. The licensee scheduled Supports B12-DCPRB-S28 and B12-DCPR-S28 for inspection in the 4th interval that concludes during Refueling Outage 28 in 2014.

Commitment 30 specified:

> "NPPD will implement the plant modifications designed to correct the main steam line support discrepancies noted in RAI B.1.20-1 prior to the period of extended operation."

The team verified that Calculation NEDC-92-143, "Main Steam Supply Piping MSIV Leakage Pathway Analysis Configured with Viscous," Revision 0, provided appropriate evaluations and modification recommendations for the main steam line supports. During the Phase 1 inspection the team had confirmed the installation of the new supports. The licensee planned to perform a confirmatory review to verify the effectiveness of the modification during the upcoming outage.

The team reviewed the vendor report recommending those modifications and the design change package used for its implementation. The modifications added rigid bracing to secure the pipe to adjacent structures proved effective in eliminating lateral movement in the pipe, as recorded by cameras and observed by program owner periodically. Additionally, the licensee installed supports with viscous fluids to help absorb the waterhammer being experienced.

Based on review of the actions implemented related to the Inservice Inspection – IWF Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 12 and Commitment 30 prior to the period of extended operation.

12. <u>B.1.21 Masonry Wall Program and Commitment 13</u>

The Masonry Wall Program aging management program ensured through visual inspections that the evaluation basis established for each in-scope masonry wall remained valid through the period of extended operation. The program included masonry walls required by 10 CFR 50.48, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components.

The team reviewed license renewal documents, implementing procedures, program documents, safety evaluation report, and updated safety analysis report. The team interviewed the program owner and performed general area walk downs of several masonry wall structures. The licensee included this aging management program in their maintenance rule structures monitoring program and used the same implementing procedures.

During a general area walk down, the team identified several cracks along grout lines in the maintenance shop masonry block walls. The licensee demonstrated that they had identified these cracks and concluded they posed no structural concern. The team verified that the licensee had taken photographs and provided a narrative description in the plant records. During review of this program area, the team identified several issues that reflected some vulnerability related to retrievable documentation. Specifically, the team:

- Identified the presence of a crack on the south end of the turbine building. The licensee identified they had not documented this crack in their structures monitoring program and initiated Condition Report 2013-07465

- Determined the licensee could not retrieve the structures monitoring program reports for the turbine building from 2007. In addition, the licensee had not issued the structures monitoring report for the turbine building inspections performed in 2012. The licensee initiated Condition Report 2013-07476 to document these deficiencies

- Determined the licensee could not retrieve the masonry wall monitoring reports for the turbine building from 2002. The licensee initiated Condition Report 2013-07333

The team determined that the licensee had not consistently documented nor could they easily retrieve structural deficiencies identified between the formal Structures Monitoring Program scheduled inspections. The licensee documented this concern in Condition Report 2013-07304 and initiated a task to modify their structures monitoring program to formalize their documentation and record retrieval process. The program owner described that the procedure change would require engineers performing inspections and/or documenting deficiencies to update the network drive, plant records, and inspection binders between 5-year inspections. The team determined that the licensee continued to refine their method for tracking and trending anomalies within the structures monitoring program to ensure periodic inspections of spaces include items that arise between inspection frequencies. The team concluded these actions were appropriate.

Commitment 13 specified:

> "Enhance the Masonry Wall Program to clarify that the control house – 161kV switchyard is included in the program. Enhance the program to clarify that structures with conditions classified as "acceptable with deficiencies" or "unacceptable" shall be entered into the Corrective Action Program."

The team verified that Procedure 3-EN-DC-150, "Condition Monitoring of Maintenance Rule Structures," Revision 2C1, listed the 161kV switchyard control house as a structure that required monitoring and specified that structures with conditions classified as "acceptable with deficiencies" or "unacceptable" shall be entered into the corrective action program. The team determined that the procedure included attachments to assist with specific items to inspect and required personnel to document discrepancies.

Based on review of the actions implemented related to the Masonry Wall Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 13 prior to the period of extended operation.

13. B.1.22 Metal-Enclosed Bus Inspection Program and Commitment 14

The Metal-Enclosed Bus Inspection Program aging management program managed the effects of aging effects associated with loosening of bolted bus bar connections and reduced insulation and insulator resistance on non-segregated bus ducts. Specifically, the program ensured the intended function of the buses were not challenged by circuit failures caused by (1) loose bolted connections, (2) degraded insulation and insulators, (3) degraded exterior enclosures both metallic and non-metallic portions (expansion boots and gaskets), and (4) degraded interior portions both metallic and non-metallic portions. The licensee established a periodic program to inspect and test activities every 10 years with the first inspection completed prior to the period of extended operation.

The licensee included the following bus ducts in this program:

- Start-Up Station Service Transformer to non-Safety Switchgear Buses 1A & 1B (start-up station service transformer metal-enclosed bus)

- Emergency Station Service Transformer to Switchgear Buses 1F & 1G (emergency station service transformer metal-enclosed bus)

The team reviewed license renewal program basis documents, aging management review documents, procedures, updated safety analysis report, and safety evaluation report. The team interviewed the program owner, reviewed completed work documents related to the inspection of the bus ducts, and reviewed corrective action documents.

Commitment 14 specified:

> "Implement the Metal-Enclosed Bus Inspection Program."

The team verified that Procedure 7.3.41, "Examination and Meggering of Non-Segregated Buses and Associated Equipment," Revision 9, required visual inspections and circuit resistance tests for the start-up and emergency station service transformer metal-enclosed buses prior to the period of extended operation and every 10 years thereafter. The team verified that the digital low resistance ohmmeter test included the bus and all of its respective bolted connections. The team determined that the procedure required personnel to visually inspect: (1) hardware and insulation for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion; (2) insulation for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation; (3) internal bus supports for structural integrity and signs of cracks; and (4) externally including the metal bus enclosure, expansion boots and gaskets.

From review of the completed inspections, the team determined that the licensee confirmed connections had low resistance and identified and corrected any noted deficiencies.

Based on review of the actions implemented related to the Metal-Enclosed Bus Inspection Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 14 prior to the period of extended operation.

14. B.1.23 Neutron Absorber Monitoring Program and Commitment 31

The Neutron Absorber Monitoring Program aging management program managed loss of material from Boral neutron absorption panels in the spent fuel racks. The program relied on representative coupon samples mounted in surveillance assemblies located in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the spent fuel racks.

The team reviewed the license renewal application, safety evaluation report, and updated safety analysis report, reviewed the commitments implementation review document, procedures, and work instructions. The team interviewed the program owner and reviewed the most recent coupon sample results.

Commitment 31 specified:

> "To verify there is no loss of neutron absorbing capacity of the Boral material, NPPD will supplement the Neutron Absorber Monitoring Program to include neutron attenuation testing of representative sample coupons. Acceptance criteria will be that measured or analyzed neutron-absorber capacity required to ensure the 5 percent subcriticality margin for the spent fuel pool is maintained assuming neutron absorber degradation is the only mechanism. Results not meeting the acceptance criteria will be entered into the CNS Corrective Action Program for disposition. One test will be performed prior to the period of extended operation, with another confirmatory test performed within the first 10 years of the period of extended operation."

The team determined that the neutron attenuation testing of the sample coupons demonstrated no degradation in the neutron absorbing capacity of the Boral material. Further, the licensee demonstrated that they would maintain the 5 percent subcriticality margin. The team verified that the licensee scheduled the next neutron attenuation test performance for Refueling Outage 29 in 2016. The team verified Procedure 10.20, "Boral Coupon Sampling," Revision 16, directed initiating a corrective action document if the test results demonstrate that Boral did not maintain the 5 percent shutdown margin.

From review of teleconference notes and discussions with experts in the Office of Nuclear Reactor Regulation, the team verified that the licensee only had to perform one additional test within the period of extended operation.

Based on review of the actions implemented related to the Neutron Absorber Monitoring Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 31 prior to the period of extended operation.

15. B.1.24 Non-Environmentally Qualified Bolted Cable Connection Program and Commitment 15

The Non-Environmentally Qualified Bolted Cable Connections Program aging management program ensured that the intended functions of in-scope power cable circuits (low and medium voltage) in their operating environments would remain tightly

connected through the period of extended operation. The program assessed 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 team reviewed license renewal program basis documents, implementing procedures, maintenance plans, updated safety analysis report, and safety evaluation report. The team interviewed the program owner, completed work documents, and corrective action documents.

Commitment 15 specified:

"Implement the Non-Environmentally Qualified Bolted Cable Connections Program."

The team verified that the licensee based their selection on the service application, circuit loading, and location. The licensee selected the samples for inspection based upon in-scope circuits with voltage less than 35kV, non-environmentally qualified, and outside of an active electrical assembly (e.g., motor-operated valve, motor control center, et cetera). Using their criteria, the licensee identified the following three in-scope bolted-splice connections:

- Cable MZA-41 - 480V E-Bay Traveling Water Screen Motor, Starter Rack ZA;
- Cable MDG1-83 - 480V Radwaste Sump Pump Z1 Motor feeder;
- Cable OS30 - 12.5kV Fire Pump E Motor feeder on 12.5kV Disconnect 20-D.

The licensee thermo-graphically scanned Connections MZA-41 and MDG1-83 and determined the connections had not degraded because the connections had no appreciable temperature difference or abnormally high temperature rise. The licensee determined the Cable OS30 bolted connections measured less than 100 micro-ohms with a digital low resistance ohmmeter that demonstrated aging stressors (heat, humidity, and vibration) had not caused loose or high resistance bolted cable connections.

Because of the limited number of in-scope connections, the licensee elected to review additional test and inspection results that would have provided an indication of the condition of bolted connections in large power circuits (less than 35kV) that could have been affected by adverse environments (high heat, high humidity and vibration). The licensee programs that periodically test circuits and provide information on bolted connections included thermography and motor circuit evaluation (megger and phase load imbalance) programs. The licensee reviewed inspection results for the previous 4 years. The thermography program results included 239 low voltage connections and 108 Medium voltage connections, and the motor circuit evaluation results included 165 low voltage and 9 medium voltage connections. The licensee identified no issues from review of the test results. The team independently assessed the evaluation, confirmed that the licensee took appropriate corrective actions for identified deficiencies, and confirmed no issues resulted from loose connections.

Based on review of the actions implemented related to the Non-Environmentally Qualified Bolted Cable Connection Program aging management program, the team concluded the aging management program would effectively manage the effects of

aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 15 prior to the period of extended operation.

16. B.1.25 Non-Environmentally Qualified Inaccessible Medium-Voltage Cables Program and Commitment 16

The Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program aging management program included periodic inspections for water collection in underground cable manholes and periodic testing of cables to detect degraded cable insulation.

The team reviewed license renewal program basis documents, aging management review documents, plant procedures, program documents, photographs of the manholes, updated safety analysis report, and safety evaluation report. The team interviewed the program owner, walked down selected cable manholes, reviewed relevant corrective action documents, and reviewed completed tests and maintenance activities.

Commitment 16 specified:

> "Implement the Non-Environmentally Qualified Inaccessible Inaccessible Medium-Voltage Cable Program. Inspections for water accumulation in manholes containing in-scope inaccessible low-voltage and medium-voltage power cables will be performed at least once every 2 years. In-scope inaccessible low-voltage power cables (cables with operating voltage from 480 V to 2 kV) that are subject to aging management review are included in this program. The in-scope inaccessible low-voltage power cables will be tested for degradation of the cable insulation prior to the period of extended operation and at least once every 10 years thereafter. A proven, commercially available test will be used for detecting deterioration due to wetting of the insulation system for all in-scope inaccessible low-voltage power cables (480 V to 2 kV). Condition-based inspections of [the manhole not dewatered by a sump pump] will be performed based on: a) potentially high water table conditions, as indicated by high river level, and b) after periods of heavy rain."

The team verified that Procedure 3.47.24, "Non-EQ Inaccessible Power Cables Program," Revision 2, specified:

- Inspect for water accumulation in manholes containing in-scope inaccessible low-voltage (480 Vac to 2kV) and medium-voltage power cables at least once every 2 years.

- Test in-scope cables for degradation of the cable insulation prior to the period of extended operation and at least once every 10 years thereafter with a proven, commercially available test capable of detecting deterioration resulting from wetting of the insulation.

- Inspect the manhole without a sump pump based upon the installed high water level annunciation.

In order to meet the condition-based inspection for the manhole not dewatered by a sump pump, the licensee installed float switches that annunciated in the control room to

alert operators of accumulation of water in the manholes. The team determined the alarm system provided a reliable method to ensure the cables would remain dry or ensure they were wetted for only a short period of time. The team determined that the licensee revised their commitment using their commitment change process and revised their updated safety analysis report in accordance with their 10 CFR 50.59 program.

The team determined that the manholes with installed sump pumps used a float switch inside the sump to activate the sump pump and had an additional float switch set at a higher water level that alerted operators that the water in the manhole had reached an elevation above where the sump pump should have removed the water. The team verified that the licensee established inspections every 2 years in the manholes with sump pumps and established inspections quarterly in manholes without sump pumps to monitor for aging effects. The licensee established plans to test the float switches annually. The licensee planned to test in-scope cables every 10 years to determine the condition of the conductor insulation.

During walk down of the newly installed float switches and review of the float testing procedures, the team determined that the procedure tested actuation of the switch without verifying the float would lift on high water level. The licensee installed the float switches in December 2012 and tested them in March 2013; therefore, the licensee would not conduct the next test until March 2014. Following questions by the team, the licensee verified that the manufacturer tested the stainless steel float for buoyancy at the factory. The licensee initiated actions to test the floats every 2 cycles and initiated a corrective maintenance work order to test the float.

The team identified the failure to verify proper operation of the float as a performance deficiency for inadequate post modification testing. The team screened this performance deficiency using Manual Chapter 0612, Appendix B, and concluded it was of minor significance. The licensee entered this into their corrective action program as Condition Report 2013-07532.

While reviewing photos of the various manholes, the team determined the conduit sealing material had degraded and water had seeped from the conduits, which could have exposed the cable in these conduits to moisture based on rust deposited on the walls of the manholes. The team questioned whether the cables in the conduits between manholes had water trapped because of low spots in the conduit. The team determined that the conduit drawings showed sloped conduits with short runs between manholes. The licensee documented the degraded sealing material in Condition Report 2013-07564 to evaluate the best approach to address the issue. The team verified that the licensee routinely tested the affected cables that demonstrated the cables remained in good condition.

Based on review of the actions implemented related to the Non-Environmentally Qualified Inaccessible Medium-Voltage Cables Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded licensee met the conditions of Commitment 16 prior to the period of extended operation.

17. B.1.26 Non-Environmentally Qualified Instrumentation Circuits Test Review Program and Commitment 17

The Non-Environmentally Qualified Instrumentation Circuits Test Review Program aging management program managed the effects of aging of instrument circuit cables through monitoring of completed test records. This aging management program assured that the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture were maintained consistent with the current licensing basis through the period of extended operation. The program included the following grouping of systems: main steam line radiation monitors, reactor building ventilation exhaust monitors, intermediate range monitors, and local power range monitors. The team verified that the licensee completed tests prior to entering the period of extended operation and scheduled test reviews once every 10 years.

The team reviewed license renewal program basis documents, aging management review documents, plant procedures, program documents, updated safety analysis report, and safety evaluation report. The team interviewed the program owner, reviewed relevant corrective action documents, reviewed completed tests and completed maintenance activities.

Commitment 17 specified:

> "Implement the Non-Environmentally Qualified Instrumentation Circuits Test Review Program."

The team determined that Procedure 3.47.26, "Non-EQ Sensitive Instrumentation Circuits Test Review Program," Revision 0, established the aging management program and required personnel to evaluate the test results of the 12 test procedures used to test and calibrate the equipment associated with the in-scope systems. The licensee evaluated whether collective test results and site cable history for these systems indicated cable insulation failures not adequately corrected or resolved through the corrective action program.

The team independently assessed the licensee evaluation of the in-scope test results from 2000-2009. The licensee tested the local power range monitor cables inside containment for the first time in 2011. The team determined that the licensee had confirmed that the cables had not experienced any age-related degradation.

Based on review of the actions implemented related to the Non-Environmentally Qualified Instrumentation Circuits Test Review aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 17 prior to the period of extended operation.

18. B.1.27 Non-Environmentally Qualified Insulated Cables and Connections Program and Commitment 18

The Non-Environmentally Qualified Insulated Cables and Connections Program aging management program managed the aging effects of cables and connections exposed to adverse localized environments caused by heat, radiation and moisture. The program

specified periodic visual inspection to confirm the absence of adverse insulated cable and connections aging effects such as embrittlement, discoloration, cracking, or surface contamination at least once every 10 years.

Commitment 18 specified:

> "Implement the Non-Environmentally Qualified Insulated Cables and Connections Program."

The team verified that Procedure 3.47.27, "Non-EQ Insulated Cables And Connections Aging Management Program," Revision 0, provided the guidance to implement the program. The licensee inspected all areas of the plant where adverse localized environments existed rather than determine representative samples. The license divided the inspection areas into two distinct groups: areas walked down during normal plant operation and areas walked down during plant outages. The areas walked down during normal plant operation had the advantage of using thermography to evaluate suspected adverse localized environments and configurations for high temperature exposures to nearby insulated cables and connections. The licensee used visual inspections of accessible insulated cables and connections during outages.

In addition, the licensee specified the following criteria when selecting the cables for inspection: (1) easily accessible (i.e. no underground ducts or small chases, no ladders or scaffolds required, safe personnel environment, etc.), (2) contain in-scope non-environmentally qualified insulated cables and connections, and (3) cables and connections not under another aging management program.

The team determined that the licensee initiated seven condition reports during the inspections performed during normal plant operation. The licensee addressed each of the identified deficiencies and determined that the deficiencies did not result from any unanalyzed adverse localized environments. The licensee initiated corrective actions to replace and reroute cabling that had experienced accelerated aging (discoloration, chalking) in the heater bay area. The team confirmed that the licensee incorporated the guidance in EPRI Report TR-109619, "Guideline for Management of Adverse Localized Environments."

Based on review of the actions implemented related to Non-Environmentally Qualified Insulated Cables and Connections Program aging management program, the team determined the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 18 prior to the period of extended operation.

19. <u>B.1.28 Oil Analysis Program and Commitment 19</u>

The Oil Analysis Program aging management program managed aging effects caused by loss of material, cracking, or fouling. The licensee monitored the oil systems through sampling and analysis of lubricating oil for detrimental contaminants, water, and particulates.

The team reviewed procedures, program documents, license renewal documents, the updated safety analysis report and the safety evaluation report. The team interviewed the program owner and reviewed work records associated with the oil analysis program

to confirm that the licensee implemented the commitments. The team verified that in-scope systems had experienced no degradation because of contaminated oil and that the licensee had identified no evidence of abnormal wear rates for the in-scope components.

Commitment 19 specified:

> "Enhance the Oil Analysis Program to include viscosity, neutralization number, and flash point determination of oil samples from components that do not have regular oil changes, along with analytical ferrography and elemental analysis for the identification of wear particles. Enhance the program to include screening for particulate and water content for oil replaced periodically. Enhance the program to formalize preliminary oil screening for water and particulates and laboratory analyses, including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met."

The team verified that Procedure 7.0.14.2, "Lubrication/Oil Analysis Program," Revision 8, (1) sampled for viscosity and neutralization number and conducted analytical ferrography and elemental analysis for components that did not have regular oil changes; (2) screened for particulates and water content for components with periodically replaced oil; (3) formalized preliminary oil screening for water and particulates and laboratory analyses, including defined acceptance criteria for all components included in the scope of the program; and (4) required personnel to initiate a corrective action document whenever a test failed to meet acceptance criteria. The inspectors verified the licensee established their acceptance criteria in accordance with industry standards.

The team determined that the program did not mention conducting a flash point determination as specified in the safety evaluation report. Subsequently, the team determined that the licensee revised their commitment using their commitment change process and revised their updated safety analysis report in accordance with their 10 CFR 50.59 program. The team agreed with the change since the licensee adopted the guidance in the GALL Report, Revision 2.

Based on review of the actions implemented related to the Oil Analysis Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 19 prior to the period of extended operation.

20. <u>B.1.29 One-Time Inspection Program and Commitment 20</u>

The One-Time Inspection Program aging management program verified the effectiveness of the Oil Analysis, Lubricating Oil, and Water Chemistry aging management programs. Specifically, the licensee reviewed the internals of a sample of mechanical components to assess whether significant aging effects had occurred. The licensee performed visual one-time inspections to address concerns related to long incubation periods for certain aging effects on structures, systems, and components.

Commitment 20 specified:

> "Implement the One-time Inspection Program."

The team reviewed the one-time inspection procedure, license renewal documents, safety evaluation report, updated safety analysis report, corrective action documents, and calculations. The team interviewed the program owner and reviewed a sample of mechanical one-time inspection visual inspection records. The team verified that the licensee (1) selected samples for each material-environment combination with consideration of operating experience, (2) identified appropriate inspection locations and examination techniques, (3) established appropriate acceptance criteria, and (4) assessed the component condition to determine if follow-up inspections would be required. The team determined that the licensee had demonstrated that they had no components that showed the effects of aging, which indicated the Water Chemistry, Oil Analysis, and Lubricating Oil aging management programs had effectively limited any aging effects.

The licensee documented in Calculation 13-012, "Flaw Tolerance Evaluation for Reactor Recirculation Flow Element," Revision 0, that they did not have to inspect their main steam and reactor recirculation nozzles as part of the one-time program since the calculation demonstrated that the nozzles were not susceptible to aging effects. The team determined that one of the six criteria reviewed included the amount of ferrite in the cast austenitic stainless steel main steam and reactor recirculation flow elements. The team determined that the amount of ferrite discussed in Calculation 13-012 had a similar basis as the cast austenitic stainless steel components discussed in the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-234, "Thermal Aging and Neutron Embrittlement Evaluation of Cast Austenitic Stainless Steels," dated December 2009, (discussed in Section 26). As described in Section 26, NRC continued to question the basis used by industry to determine the amount of ferrite and whether cast austenitic stainless steel components needed to be managed for aging effects.

Because of the uncertainty related to ferrite in cast austenitic stainless steel components, the team determined that the licensee had inappropriately excluded these flow nozzles from being visually or volumetrically examined. The licensee generated a new commitment in Letter NLS2013100, "New License Renewal Commitment," dated November 26, 2013. Commitment 41 specified:

> "NPPD will confirm that the reactor recirculation and main steam line flow restrictor CASS materials are either: (a) not greater than 25 percent ferrite, (b) will perform a flaw tolerance evaluation, or (c) will perform a qualified visual or volumetric examination. This will be completed within 3 years after the period of extended operation."

Because the licensee had not entered the period of extended operation, the licensee revised the due date for this commitment to January 18, 2017, which matched the dates for the other commitments. The licensee further indicated that they would implement the appropriate corrective actions if they were determined to exceed 25 percent ferrite in their cast austenitic stainless steel components. The team considered this an appropriate corrective action.

Based on review of the actions implemented related to the One-Time Inspection Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 20 prior to the period of extended operation with one exception. The team determined that the licensee took appropriate action to track resolution of the amount of ferrite in cast austenitic stainless steel components to determine the most appropriate action related to their main steam line and reactor recirculation flow elements as Commitment 41.

21. B.1.30 One-Time Inspection – Small-Bore Piping Program and Commitments 21 and 32

The One-Time Inspection – Small-Bore Piping Program aging management program managed the effects of cracking through the use of volumetric examinations on American Society of Mechanical Engineers (ASME) Code Class 1 piping less than 4 inches nominal pipe size (small bore), which included pipe, fittings, and branch connections. The licensee selected their sample based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Class 1 small bore piping locations.

The team reviewed procedures, program documents, license renewal documents, safety evaluation report and updated safety analysis report. The team reviewed selected inspection records and interviewed the program owner. The team verified that the licensee took an appropriate sample population and included small bore pipe inspections in their inservice inspection program.

Commitment 21 specified:

> "Implement the One-time Inspection Small-Bore Piping Program."

The team determined that Engineering Report CNS-RPT-13-LRIMR-06, "One Time Inspection – Small Bore Piping Program Report," Revision 0, summarized the results of licensee actions related to implementing this aging management program.

The team verified that the licensee tracked future changes to the 5th and 6th 10-year Inservice Inspection Intervals with LO 2013-05190-003 and LO 2013-05190-004, respectively. The team determined that the licensee planned to perform volumetric examinations on Socket Welds SLC-BJ-8, SLC-BJ-9, and RVD-BJ-10 during each of the subsequent 10-year inspection intervals

Commitment 32 specified:

> "During the period of extended operation, NPPD will perform periodic volumetric examinations of Class 1 socket weld connections. Three Class 1 socket welds will receive volumetric examination during each 10 year ISI interval. The examination method will be a volumetric examination of the base metal ½-inch beyond the toe of the socket fillet weld which allows for the use of qualified ultrasonic examination techniques as close as possible to the fillet weld. The volumetric examinations will be performed by certified examiners following guidelines set forth in ASME Section V, Article 4 consistent with the guidelines for examination volume of ½-inch beyond the toe of the weld as established in MRP-146, 'Materials Reliability

Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines.'"

The team verified that the licensee had documented inspection results related to ultrasonic examinations of the Class-1 Small Bore Pipe Socket Welds SLC-BJ-8, SLC-BJ-9, and RVD-BJ-10, and Small Bore Pipe Welds RVD-BJ-17, RVD-BJ-18, RSA-BJ-7x, RSA-BJ-8x, RSA-BJ-9, and RSA-BJ-10. The team verified that the licensee performed the volumetric examinations as specified in ASME Section V, Article 4. The team determined that Procedure 3.28.5.UT.SOC, "Socket Weld Ultrasonic Phased Array Weld Examination," Revision 0, required personnel performing the examinations be certified to Ultrasonic Testing Level II or III and the examinations be initiated as close to the fillet weld as possible.

Based on review of the actions implemented related to the One-Time Inspection – Small-Bore Piping Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitments 21 and 32 prior to the period of extended operation.

22. B.1.31 Periodic Surveillance and Preventive Maintenance Program and Commitment 22

The Periodic Surveillance and Preventive Maintenance Program aging management program managed the following aging effects: loss of material, cracking, change in material properties, loss of material by wear, and fouling. While primarily used for managing the effects of aging on internal surfaces, the program was used to managing loss of material from external surfaces for situations in which external and internal material and environment combinations were the same.

The team reviewed license renewal program basis documents, aging management review documents, procedures, maintenance and engineering training requirements, training records, updated safety analysis report and the safety evaluation report. The team interviewed the program owner, reviewed relevant condition reports and surveillances results.

Commitment 22 specified:

"Enhance the Periodic Surveillance and Preventive Maintenance Program to include the activities described in the table provided in the program description of LRA Section B. 1.31. For each activity that refers to a representative sample, a representative sample will be selected for each unique material and environment combination. The sample size will be determined in accordance with Chapter 4 of EPRI 107514, 'Age-Related Degradation Inspection Method and Demonstration,' which outlines a method to determine the number of inspections required for 90 percent confidence that 90 percent of the population does not experience degradation."

Procedure 3.47.31, "Periodic Surveillance and Preventative Maintenance (PSPM) Program," Revision 0, described conduct of this program. The program verified for miscellaneous components that aging effects were not occurring or were acceptable through the end of the period of extended operation. The licensee included components in this program not managed by other aging management programs. The program

supplemented the guidance in the existing preventive maintenance and surveillance programs. The licensee created 48 separate groups of components that represented different material-environment combinations and planned to apply the sampling method to each group of components. The licensee stated that they would evaluate each component once every 5 years throughout the period of extended of operation. The licensee identified the initial list of components and scheduled the inspections expected to occur during Refuel Outage 28 in 2014. Procedure 3.47.31 required all maintenance and engineering personnel attend training related to identifying aging effects.

The team determined that the licensee revised their sampling method to agree with the sampling method described in GALL Report, Revision 2 that specified performing inspections on 20 percent of the sample population up to a maximum of 25 components. The team determined that the licensee appropriately revised their commitment using their commitment change process and revised their updated safety analysis report in accordance with their 10 CFR 50.59 program.

The licensee planned to schedule the aging effect inspections to coincide with planned maintenance or modification activities. The licensee had not completed the scheduling of each component aging inspection for the first 5-year period at the time of this inspection. The licensee had created the online (12-month) and offline (24-month) recurring tasks that reminded the aging management coordinator to promulgate the component schedules to the individual system engineers and component engineers of the equipment to choose the most appropriate samples to inspect. The licensee expected that this would result in sample selections most likely to show evidence of aging (e.g., worst environment or oldest installed component).

Based on review of the actions implemented related to the Periodic Surveillance and Preventive Maintenance Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitments 22 prior to the period of extended operation.

23. <u>B.1.33 Reactor Vessel Surveillance Program and Commitment 23</u>

The Reactor Vessel Surveillance Program aging management program managed the reduction in fracture toughness of reactor vessel beltline materials to assure that the reactor pressure vessel pressure boundary function was maintained through the period of extended operation. The licensee received the NRC approval to use the BWRVIP Integrated Surveillance Program. As BWRVIP Integrated Surveillance Program capsule test reports become available for reactor pressure vessel materials representative of the Cooper Nuclear Station reactor vessel, the licensee would update any actual shift in the reference temperature for nil ductility transition of the reactor vessel material. In accordance with 10 CFR Part 50 Appendices G and H, the licensee reviewed relevant test reports to assure compliance with fracture toughness requirements and pressure temperature limits.

The team reviewed applicable program procedures, aging management program guidance, license renewal documents, updated safety analysis report, safety evaluation report, and industry documents. The team discussed the program with the NRC personnel and interviewed the program owner.

Commitment 23 specified:

> "Enhance the Reactor Vessel Surveillance Program to add that if the CNS license renewal capsule is removed from the reactor vessel without the intent to test it, the capsule will be stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary. Enhance the program to ensure that the additional requirements that are specified in the final NRC safety evaluation for BWRVIP-116 will be addressed before the period of extended operation."

The team reviewed BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," dated July 2003 and the NRC safety evaluation report for BWRVIP-116. The team determined from interviews with the program owner that the licensee identified one recommendation from BWRVIP-116 that their program did not already require. Specifically, the licensee needed to add the requirement to submit a license amendment for the NRC approval if they planned to change their neutron fluence determination methodology.

The team verified Procedure 3.28.4, "Integrated Surveillance Program," Revision 11 contained precautions to obtain the NRC approval if they needed to change their neutron fluence determination methodology and to determine if the desired methodology had been or would be benchmarked against existing dosimetry databases. The team determined that the licensee used the NRC-approved RAMA code as its neutron fluence methodology.

The team verified that the licensee had committed to meeting the prescribed capsule testing schedule. Further, the team verified that Procedure 3.28.4 contained guidance related to storing test capsules in a manner that would permit its future use, if the licensee removed the capsule without the intent to test it.

Based on review of the actions implemented related to the Reactor Vessel Surveillance Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the condition of Commitment 23 prior to the period of extended operation.

24. <u>B.1.34 Selective Leaching Program and Commitment 24</u>

The Selective Leaching Program aging management program managed the effects of aging by ensuring the integrity of components made of cast iron, bronze, brass, and other alloys exposed to condensation, raw water, steam, treated water, and soil (groundwater) that may lead to selective leaching. The licensee performed one-time visual inspections, hardness measurements, and destructive testing inspections of selected components to determine whether loss of material resulting from selective leaching occurred. Based on the results of the inspections, the licensee would determine whether any material environment combination experienced selective leaching.

The team reviewed licensee procedures, program documents, license renewal documents, safety evaluation report, and updated safety analysis report. The team

interviewed the program owner, reviewed inspection records, and corrective action documents.

Commitment 24 specified:

> "Implement the Selective Leaching Program."

The team determined that the licensee reviewed for selective leaching in five environments: treated water, steam, raw water, condensation, and soil (groundwater). The licensee inspected 78 components for selective leaching in 22 different systems. The licensee initiated 17 condition reports 9 of which included gray cast iron in the service water and fire protection water systems. Because the gray cast iron/treated water material environment combination indicated evidence of selective leaching, the licensee initiated actions to monitor for the effects of aging related to selective leaching for gray cast iron components in a treated water environment. The team determined that the licensee developed a repetitive task to take a sample from the fire water system once every 5 years if an opportunistic inspection of a component in the fire water systems had not occurred.

Based on review of the actions implemented related to the Selective Leaching Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the condition of Commitments 24 prior to the period of extended operation.

25. <u>B.1.36 Structures Monitoring Program and Commitment 25</u>

The Structures Monitoring Program aging management program managed the effects of aging of structures and commodities through periodic inspections to ensure that aging degradation would be detected, evaluated, and repaired prior to any loss of intended functions.

The team reviewed plant procedures, program documents, updated safety analysis report, safety evaluation report, and license renewal documents. The team reviewed corrective action documents, interviewed the program owner and walked down selected plant areas. The team determined that the licensee based their inspection requirements on numerous industry documents that required structures be designed to withstand seismic events.

Commitment 25 specified:

> "Revise procedures to ensure the structures described in the LRA Section B.1.36 table are included in the program. Revise procedures to ensure the commodities described in the LRA Section B.1.36 table are inspected, as applicable. Enhance the Structures Monitoring Program to add guidance to inspect inaccessible concrete areas that are submerged or below grade which may become exposed due to excavation, construction or other activities. CNS will also inspect inaccessible concrete areas when observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program to perform inspections of elastomers (seals, gaskets, and roof elastomers) to identify cracking and change in material properties. Enhance

the Structures Monitoring Program to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every 5 years). CNS will obtain samples from a well that is representative of the groundwater surrounding below-grade site structures. Samples will be monitored for Sulfates, pH and chlorides. Enhance the Structures Monitoring Program to add guidance to perform visual structural examinations of wood to identify loss of material and change in material properties. Enhance the Structures Monitoring Program to add guidance to perform visual structural monitoring of the oil tank bunker crushed rock fill to identify loss of form. Enhance the Structures Monitoring Program to clarify that structures with conditions classified as "acceptable with deficiencies" or "unacceptable" shall be entered into the Corrective Action Program. Supplement 1: NPPD will enhance the Structures Monitoring Program procedure to: a) include more detailed guidance on acceptance criteria (using ACI documents ACI 201.1R-92, and ACI 349.3R-96) to preclude potential inconsistent application of inspection criteria, and b) provide more detailed guidance on trending."

The team verified that the licensee had inspected their in-scope structures in accordance with the procedures that implemented their maintenance rule structures monitoring program. Further the team verified that the licensee had performed the following activities related to Commitment 25.

The team verified that Procedure 3-EN-DC-150, "Condition Monitoring of Maintenance Rule Structures," Revision 2C1: (1) included the structures and commodities listed in the license renewal application; (2) specified inspecting elastomers (seals, gaskets, and roof elastomers) to identify cracking and change in material properties; (3) required inspecting wood structures to identify loss of material and change in material properties; (4) specified inspecting the oil tank bunker crushed rock fill to identify loss of form; (5) specified that structures with conditions classified as "acceptable with deficiencies" or "unacceptable" shall be entered into the corrective action program; and (6) included detailed guidance to preclude potential inconsistent application of inspection criteria and specified proper documentation to allow trending.

The team reviewed the groundwater sample records and evaluation performed prior to the period of extended operation and determined that the ground water parameters remained within the required limits. The team verified that Procedure 8.ENV.9, "Groundwater Monitoring Program Sampling, Monitoring, and Administrative Requirements," Revision 9, specified that the license take samples from monitoring wells GMW-2, GMW-8, and GMW-10 to ensure they represented site soil conditions. The procedure required that the samples be taken once every 5 years, included monitoring for sulfates, pH and chlorides, and required an engineering evaluation of the groundwater samples to assess aggressiveness of groundwater on concrete.

The team verified that Procedure 3.6.5, "Excavation and Ground Penetrating Activities," Revision 18, specified inspecting inaccessible concrete areas (1) that are submerged or below grade which may become exposed due to excavation, construction or other activities and (2) when observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation was occurring.

Based on review of the actions implemented related to the Structures Monitoring Program aging management program, the team concluded the aging management

program would effectively manage the effects of aging during the period of extended operation. The team concluded the licensee met the conditions of Commitment 25 prior to the period of extended operation.

26. B.1.37 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel and Commitment 29

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program aging management program managed the reduction of fracture toughness resulting from thermal aging and reduction of fracture toughness resulting from radiation embrittlement to prevent any in loss of intended function of reactor vessel internal components. This program evaluated cast austenitic stainless steel components in the reactor vessel internals and required non-destructive examinations as appropriate.

The team reviewed license renewal and industry documents and interviewed the program owner. The team determined that the licensee had not established a formal program because they believed that they did not have any cast austenitic stainless steel components that had more than 25 percent ferrite content.

Commitment 29 specified:

> "NPPD will confirm there are no CASS materials with greater than 25 percent ferrite or provide a flaw evaluation methodology for CASS internal components with greater than 25 percent ferrite for staff review and approval. This will be provided at least 2 years prior to the period of extended operation. NPPD expects to implement this commitment by a generic analysis sponsored by the BWRVIP in collaboration with EPRI."

The team determined that EPRI submitted BWRVIP-234 for review by the NRC in December 2009. At the time of this submittal, the licensee determined that they would use the NRC acceptance and approval of BWRVIP-234 to demonstrate that they had less than 25 percent ferrite in their cast austenitic stainless steel components. Because they believed that the NRC would approve BWRVIP-234 prior to January 18, 2014, the licensee did not provide a flaw evaluation methodology prior to January 18, 2012.

During this inspection, the NRC had not approved BWRVIP-234 and would not approve it by January 18, 2014. The team determined the following chronology related to review of BWRVIP-234. In a letter dated September 28, 2011 the NRC requested additional information. On September 18, 2012 EPRI responded to the requests for additional information. The NRC initiated a second request for additional information on April 24, 2013. The team determined that the licensee tracked completion of this commitment by Condition Report CNSLO-2011-00258.

Because the licensee had not entered the period of extended operation, the licensee revised the due date for this commitment to January 18, 2017, which matched the dates for the other commitments that will be completed after entering the period of extended operation. The licensee further indicated that they would implement the appropriate corrective actions if they were determined to exceed 25 percent ferrite in their cast austenitic stainless steel components. The team considered this an appropriate corrective action.

Based on review of the actions implemented related to the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel aging management program, the team could not determine whether the program would effectively manage the effects of aging during the period of extended operation. Because of concerns related to determining the amount of ferrite in cast austenitic stainless steel, the team was unable to ensure the licensee met the conditions of Commitment 29; consequently, Commitment 29 remained open.

.02 Aging Management Programs without any Associated Commitments

a. Inspection Scope

The team evaluated whether the licensee met the commitments listed below, as described in NUREG-1944, "Safety Evaluation Report (SER) Related to the License Renewal of Cooper Nuclear Station." The team verified that the licensee implemented procedures, documented inspection results, initiated corrective action documents, and provided training to implementing personnel.

The team reviewed supporting documents including implementing procedures, work orders, inspection reports, engineering evaluations, and condition reports; conducted interviews with licensee staff, including the program owners; observed in-process outage activities; and performed visual inspection of structures, systems, and components including those not accessible during power operation to verify that the licensee completed the necessary actions to comply with the license conditions stipulated in the renewed facility operating license.

Specific documents reviewed are listed in the report attachment.

b. Findings and Observations

1. B.1.4 Boiling Water Reactor Control Rod Drive Return Line Nozzle Program

The Boiling Water Reactor Control Rod Drive Return Line Nozzle Program aging management program monitored for crack initiation and growth on the intended function of the control rod drive return line nozzle. The licensee implemented this program in accordance with the BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," as part of the Boiling Water Reactor Stress Corrosion Cracking Program.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed nondestructive examination records.

The team determined that the licensee cut and capped the control rod drive return line nozzle to mitigate fatigue cracking. The licensee conducted nondestructive examinations as specified by their inservice inspection program, which included ultrasonic inspection of the nozzle inside radius section and nozzle-to-vessel weld. The licensee also ultrasonically examined the control rod drive return line nozzle-to-cap weld. The team determined that the licensee performed the examinations as specified in industry guidelines and regulatory requirements.

Based on review of the actions implemented related to the Boiling Water Reactor Control Rod Drive Return Line Nozzle Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

2. B.1.5 Boiling Water Reactor Feedwater Nozzle Program

The Boiling Water Reactor Feedwater Nozzle Program aging management program monitored for crack initiation and growth on their feedwater nozzles. The licensee had removed the nozzle cladding and installed a double piston ring, triple thermal sleeve sparger to mitigate cracking.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed nondestructive examination records. The license implemented enhanced nondestructive examinations of the feedwater nozzles in accordance with their inservice inspection program and the recommendations of Calculation NE-523-A71-0594A, "Alternate BWR Feedwater Nozzle Inspection Requirements." The team verified that the licensee had performed the required ultrasonic examinations and identified no defects.

Based on review of the actions implemented related to the Boiling Water Reactor Feedwater Nozzle Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

3. B.1.6 Boiling Water Reactor Penetrations Program

The Boiling Water Reactor Penetrations Program aging management program monitored for crack initiation and growth on the standby liquid control injection and instrument penetrations. The licensee implemented this program in accordance with BWRVIP-27-A, "BWR Vessel and Internals Project – BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines," and BWRVIP-49-A, "BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines." In addition, the licensee credited the controls for reactor coolant water chemistry to ensure the long-term integrity of vessel penetrations and nozzles, as specified in BWRVIP-130, "BWR Vessel and Internals Project BWR Water Chemistry Guidelines."

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed nondestructive examination records. The team verified the licensee implemented the actions related to inspection schedule, method, personnel qualification, and sample expansion, as specified in industry and regulatory documents.

Based on review of the actions implemented related to the Boiling Water Reactor Penetrations Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

4. B.1.7 Boiling Water Reactor Stress Corrosion Cracking Program

The Boiling Water Reactor Stress Corrosion Cracking Program aging management program included (1) preventive measures to mitigate intergranular stress corrosion cracking and (2) nondestructive examinations and flaw evaluation of reactor coolant pressure boundary components made of stainless steel, cast austenitic stainless steel, or nickel alloy.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed nondestructive examination records. The team verified that the licensee implemented the required chemistry controls to mitigate the effects of intergranular stress corrosion cracking and performed the nondestructive examinations as recommended.

Based on review of the actions implemented related to the Boiling Water Reactor Stress Corrosion Cracking Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

5. B.1.8 Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program

The Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program aging management program managed the aging effects on specified reactor vessel internals welds. The program included (1) nondestructive examinations and flaw evaluation in accordance with the guidelines of BWRVIP-48-A, “BWR Vessel and Internals Project Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” and (2) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130 to ensure the long-term integrity and safe operation of reactor vessel inside diameter attachment welds and support pads.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed nondestructive examination records. The team verified that the licensee had performed the required examinations and that the examinations did not identify any deficiencies.

Based on review of the actions implemented related to the Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

6. B.1.11 Containment Leak Rate Program

The Containment Leak Rate Program aging management program specified periodic containment leak rate tests to assure that (1) leakage from the containment and systems penetrating containment did not exceed allowable values specified in the technical specifications and (2) proper maintenance and repairs were made to systems and components penetrating containment during the service life of containment. The team determined that the licensee implemented the performance-based option allowed by regulations.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team discussed containment leak rate testing with the program owner. The team reviewed a sample of exceptions to the testing requirements and determined the licensee took appropriate exceptions. The team determined that the licensee properly performed local leak rate tests. The team determined that the licensee maintained their containment leakage rate within the limits specified by technical specifications and implemented appropriate maintenance when valves had excessive leakage.

Based on review of the actions implemented related to the Containment Leak Rate Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

7. B.1.32 Reactor Head Closure Studs

The Reactor Head Closure Studs aging management program included periodic inspection of the reactor head closure studs for indications of potential problems, including loss of material, crack initiation, and loss of preload. The program implemented guidelines for defect characterization and deficiency resolution.

The team reviewed the aging management program evaluation report, license renewal documents, safety evaluation report, updated safety analysis report, implementing procedures, and corrective action documents. The team reviewed selected work orders and interviewed the program owner. The team determined that the program owner was familiar with the requirements of the implementing procedure. From review of inserivce inspection records, the team verified that the licensee examinations followed prescribed guidelines and supported a robust program.

Based on review of the actions implemented related to the Reactor Head Closure Stud aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

8. B.1.38 Water Chemistry Control – Auxiliary Systems Program

The Water Chemistry Control – Auxiliary Systems Program aging management program managed loss of material and cracking for components exposed to treated water and steam. The licensee sampled and analyzed water in auxiliary condensate drain system components, auxiliary steam system components, and heating and ventilation system components to minimize component exposure to aggressive environments.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team discussed the programs with plant chemistry personnel. The team reviewed chemistry results for the last 3 years for monitored parameters in the auxiliary condensate drain, auxiliary steam, and heating and ventilation system components. Licensee personnel had initiated condition reports each time a monitored parameter exceeded a monitoring limit. From review of corrective actions and discussions with chemistry personnel, the team concluded that the licensee effectively monitored and managed the effects of aging

for the auxiliary condensate drain, auxiliary steam, and heating and ventilation system components.

Based on review of the actions implemented related to the Water Chemistry Control – Auxiliary Systems Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

9. B.1.39 Water Chemistry Control – Boiling Water Reactor Program

The Water Chemistry Control – Boiling Water Reactor Program aging management program managed aging effects by mitigating corrosion and cracking mechanisms through use of chemistry. The licensee monitored and optimized water chemistry in accordance with the specifications in BWRVIP-130. The licensee followed the limits specified for primary water, for condensate and feedwater, and for control rod drive mechanism cooling water. The licensee also used the limits recommended for the torus, condensate storage tank, demineralized water storage tanks, and spent fuel pool.

Additionally, the licensee instituted hydrogen water chemistry to reduce the oxygen in the reactor vessel and noble metal chemical addition to limit the potential for intergranular stress corrosion cracking.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team interviewed the program owner and reviewed chemistry data for the last 5 years for the reactor water and feedwater systems. The licensee included high and low action levels and identified the condition reports anytime an action level had been exceeded. The team reviewed each condition report and determined that the licensee had appropriately resolved the condition anytime a chemistry parameter exceeded an action level. From review of corrective actions and discussions with chemistry personnel, the team concluded that the licensee effectively monitored and managed the effects of aging in the reactor vessel.

Based on review of the actions implemented related to the Water Chemistry Control – Boiling Water Reactor Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

10. B.1.40 Water Chemistry Control – Closed Cooling Water Program

The Water Chemistry Control – Closed Cooling Water Program aging management program used preventive measures to manage loss of material, cracking, and fouling for components in the following closed cooling water systems: diesel generator jacket water, reactor equipment cooling, and turbine equipment cooling. The licensee monitored and controlled closed cooling water chemistry based on EPRI guidance for closed cooling water chemistry.

The team reviewed the implementing procedures, program documents, license renewal documents, updated safety analysis report, and the safety evaluation report. The team discussed the programs with plant chemistry personnel. The team reviewed chemistry results for the last 5 years for monitored parameters in the diesel generator jacket water,

reactor equipment cooling, and turbine equipment cooling systems. Licensee personnel had initiated condition reports each time a monitored parameter exceeded a monitoring limit. From review of corrective actions and discussions with chemistry personnel, the team concluded that the licensee effectively monitored and managed the effects of aging for the diesel generator jacket water, reactor equipment cooling, and turbine equipment cooling systems.

For the Water Chemistry Control – Closed Cooling Water Program aging management program, the team concluded the aging management program would effectively manage the effects of aging during the period of extended operation.

.03 Time-Limited Aging Analyses

The licensee had no time-limited aging analyses that had undergone any changes since the review and approval of the license renewal amendment. Consequently, the inspection team did not review any time-limited aging analyses.

.04 Newly Identified Components

a. Inspection Scope

The team evaluated whether the licensee reviewed and identified newly identified components and incorporated these components into the appropriate aging management programs.

b. Observations and Findings

The licensee compared the plant equipment database used to prepare the license renewal application to the master equipment list to evaluate whether they had inadvertently excluded any components from the scoping and screening process. Similarly, the licensee evaluated components originally considered outside the scope of license renewal but subsequent plant modifications required them to be included in the scope of components subject to aging management review. Additionally, the licensee reviewed engineering change packages completed since the issuance of the renewed license to identify those engineering changes that could potentially result in newly identified components under 10 CFR 54.37(b) (e.g. safety classification changes to components, and/or plant configuration changes).

The licensee identified two aluminum valve bodies in the turbine-generator lubricating oil and turbine-generator electro-hydraulic fluid systems that needed to be added to components requiring aging management. The licensee documented this determination in Condition Report 2012-00744 and listed the components in Appendix K, Table K-2-1, “Newly-Identified SCCs Requiring Aging Management.”

On the basis of the sample selected for review, the team determined that the licensee took appropriate actions to identify “newly identified” structures, systems, and components. The team determined that the licensee had established an appropriate scope and appropriately evaluated for management of aging affects.

.05 Verification of Updated Safety Analysis Supplement

a. Inspection Scope

The team evaluated whether the licensee revised the updated safety analysis report supplement to reflect the aging management program and time-limited aging analysis descriptions in the safety evaluation report. The team compared the aging management program and time-limited aging analysis descriptions to the programs being implemented to determine whether they matched the programs being implemented and whether the licensee had incorporated the newly identified components into the updated safety analysis report supplement.

b. Observations and Findings

Based on the minor differences between the license renewal application and the updated safety analysis report supplement, the team determined that the licensee appropriately described their aging management programs in the updated safety analysis report. The team verified that the licensee had appropriated used their 10 CFR 50.59 program to make changes to the commitments.

.06 Review of Administrative Controls

a. Inspection Scope

The team reviewed administrative controls related to changing commitments, identifying and incorporating operating experience related to aging effects, and identifying deficiencies in the corrective action program attributable to aging effects. The team evaluated whether the licensee updated aging management programs to account for operating experience issued since the licensee had received the renewed license and any changes to the GALL Report or other approved topical reports.

The team reviewed the corrective action program to evaluate whether the applicant established a method to evaluate the effects of aging and to identify deficiencies that might have resulted from aging effects.

The team sampled corrective action documents, interviewed personnel, evaluated corrective actions implemented, and reviewed process documents during this inspection.

b. Observations and Findings

The team determined that the licensee had established appropriate administrative controls. Specifically, the team verified that the licensee had properly changed their commitments, had initiated corrective action documents when they identified aging effects, and monitored for operating experience.

40A6 Meetings, Including Exit

The team presented the initial inspection results to Mr. Ken Higginbotham, General Manager Plant Operations, and other members of the licensee staff during an exit meeting conducted on November 7, 2013. The licensee acknowledged the NRC inspection observations and findings. The team retained no proprietary information and verified that no proprietary information was documented in this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

PERSONS CONTACTED

Licensee

J. Ackerman, Engineering Programs and Components Engineer
T. Barker, Manager, Engineering Programs and Components
L. Bray, Licensing Specialist
D. Bremer, License Renewal Project Manager
S. Charbonnet, Nondestructive Examination Coordinator
J. Dykstra, Engineering Programs and Components Engineer
S. Freborg, Aging Management Coordinator
G. Gardner, Design Engineering Supervisor
J. Gren, Electrical System Engineer
K. Higginbotham, General Manager Plant Operations
V. Hoefler, Periodic Surveillance Preventive Maintenance Program Owner
J. Jackson, Civil Design Engineer
D. Kiekel, Electrical System Engineer
P. Leiniger, Engineering Programs and Components Engineer
C. Long, Fire Protection Program Engineer
T. McClure Engineering Programs and Components Engineer
M. Metzger, Diesel Generator System Engineer
E. Murphy, License Renewal Assistant
C. Parkyn, Reactor Engineer
R. Penfield, Nuclear Safety Assurance Manager
D. Stuhr, Engineering Programs and Components Engineer
B. Thacker, Engineering Programs and Components Supervisor
D. Vanderkamp, Licensing Manager
W. Victor, Senior License Renewal Project Engineer
R. Weller, Chemistry Technician

NRC

C. Henderson, Resident Inspector
A. Obodoako, Materials Engineer, NRR
T. Tran, Project Manager, License Renewal Projects Branch 1

COMMITMENTS

NRC closed Commitments 4, 26, 27, and 28 in Inspection Report 05000298/2012008.

The team closed Commitments 1, 2, 3, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 30, 31, 32, 36, 37, 38, 39, and 40

As described in the report, the team did not close the following: Commitments 29, 33, 34, 35 and 41.

DOCUMENTS REVIEWED

General

LETTERS

NUMBER	TITLE	DATE
NLS2011111	Completion of License Renewal Commitments NLS2009100-2, NLS2009100-3, and NLS2008071-26	December 28, 2011
NLS2011114	Completion of License Renewal Commitment NLS2008071-08	December 23, 2011
NLS2012002	Completion of License Renewal Commitment NLS2009100-1 (Revision 1)	January 16, 2012
NLS2012118	Completion of License Renewal Commitment NLS2008071-04	October 22, 2012
NLS2012022	Revision to License Renewal Commitments NLS2008071-20 and NLS2008071-24	March 30, 2012
NLS2013014	License Amendment Request to Revise License Renewal License Condition 2.E	February 12, 2013
NLS2013037	Rescission of License Renewal Commitments NLS2008071-20 and NLS2008071-24 Revisions	March 20, 2013
NLS2013081	Implementation of License Renewal Commitments	September 4, 2013
NLS2013090	Implementation of License Renewal Commitments	October 3, 2013
NLS2013097	Extension of License Renewal Commitment NLS2009100-3 Committed Date	October 31, 2013
	Cooper Nuclear Station – Issuance of Amendment Re: Modification of Renewed Operating License Condition 2E	September 12, 2013

MISCELLANEOUS

NUMBER	TITLE	REVISION
Procedure 3.47	License Renewal Implementation Program	0

Aging Management Programs with Commitments

B.1.1 Aboveground Steel Tanks Program and Commitment 1

CONDITON REPORTS (CNS-CR-)

2009-02354	2009-05851	2009-05856	2009-07305	2012-06247

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 3.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical Aboveground Steel Tanks Program	3
CNS-RPT-10-LRIMR-29	Aboveground Steel Tanks Program - Readiness Report	0
CNS-RPT-13-LRILR-02	B.1.1 Commitments Implementation Review Aboveground Steel Tanks Program	0
NUREG-1944, Section 3.0.3.1.1	Aboveground Steel Tanks Program	September 1, 2010

MAINTENANCE PLANS (8000000)

25331 39134 41451

MISCELLANEOUS

NUMBER	TITLE	REVISION
CED 6030745	Replacement Fire Water Storage Tank Insulation	0
NEDC 96-023	Corrosion Acceptance Criteria for Storage and Pressurized Tanks at CNS	0

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

PROCEDURES

NUMBER	TITLE	REVISION
3.10.1	UT Thickness Measurements and Gridding Procedure	1
3.13.2	Above Ground Steel Tanks Program	1

WORK ORDERS

4703937 4715927

B.1.2 Bolting Integrity Program and Commitment 2

CONDITON REPORTS (CNS-CR-)

2005-02602 2005-02708 2005-06397 2006-08385 2005-00635

LICENSE RENEWAL

NUMBER	TITLE	REVISION/DATE
CNS-RPT-07-LRD07, Section 4.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Bolting Integrity	3
CNS-RPT-13-LRILR-03	B.1.2 Commitments Implementation Review – Bolting Integrity	0
NUREG-1944, Section 3.0.3.2.1	Bolting Integrity Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	DATE
EPRI NP-5769	Degradation and Failure of Bolting in Nuclear Power Plants	April 1988
TR-104213	Bolted Joint Maintenance and Applications Guide	December 1995

PROCEDURES

NUMBER	TITLE	REVISION
3-EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2C1
7.2.71	Bolting and Torque Program	38

WORK ORDERS

4283391	4306548	4363238	4301558	4455991
4436712	4434534			

B.1.3 Buried Piping and Tanks Inspection Program and Commitments 3, 36, 37, 38, 39, and 40

CONDITION REPORTS (CNS-CR-)

2011-10180	2013-03242	2013-03321	2013-04329	2013-04492
2013-04759	2013-05033	2013-05123	2013-05212	2013-05436
2013-05863	2013-05864	2013-06129		

LETTERS

NUMBER	TITLE	DATE
NLS2009040	Response to Request for Additional Information for License Renewal Application – Aging Management Programs	June 15, 2009
NLS2010050	Response to Open Items from the Safety Evaluation Report and Request for Additional Information Related to the License Renewal of Cooper Nuclear Station	May 4, 2010

LETTERS

NUMBER	TITLE	DATE
NLS2010062	Revisions and Supplements to Responses to Requests for Additional Information Related to the License Renewal of Cooper Nuclear Station	July 23, 2010

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 3.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Buried Piping and Tanks Inspection	3
CNS-RPT-13-LRILR-04	B.1.3 Commitments Implementation Review Buried Piping and Tanks Program	0
CNS-RPT-13-LRIMR-02	Buried Piping and Tanks Program – Readiness Report	0
NUREG-1944, Section 3.0.3.1.2	Buried Piping and Tanks Inspection	September 1, 2010

ENGINEERING CHANGES

NUMBER	TITLE	REVISION/DATE
CED 6032682	Cathodic Protection System Upgrade – Service Water Pump Room and Fire Protection Pump House	August 4, 2010
EE 08-036	Cathodic Protection Upgrades	0
EE 10-025	Evaluation of Class 1 Structural Fill Penetrations Required for Cathodic Protection Anode Groundbed	0

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
1000098	Site Specific Risk Report: Cooper Nuclear Station	December 22, 2010
1100302.401	Soil Corrosivity Analysis and Engineering Assessment of Effects on Buried Piping	December 4, 2012
100302.401	Area Potential and Earth Current Survey – Cooper Nuclear Station	December 3, 2012
1101551.406	Soil Analysis Results for Cooper Nuclear Station	October 7, 2013
1104551.407	Summary of 2013 Direct Examinations at Cooper Nuclear Station	October 7, 2013
1200599.402	ILI Inspection of High Pressure Coolant Injection Suction Line 18” HP-5 at Cooper Nuclear Station	December 7, 2012

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
340310017	Final Report for the Survey of the New Replacement Cathodic Protection Systems Installed at Cooper Nuclear Station	December 5, 2011
340310310	Report for the Structure-to-Soil Potential Survey of the Various Piping Systems Located in the Basement at Cooper Nuclear Station	August 7, 2012
EPRI 1021175	Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks	December 2010
ER-2012-002	Cooper Nuclear Station Four Buried Pipe Excavation Feasibility and Risk Study	August 22, 2012
JOB #311531	Final Report – Annual Survey of the Cathodic Protection Systems Installed at the Cooper Nuclear Station	September 2007
NACE RP0285	Corrosion Control of Underground Storage Tank Systems by Cathodic Protection	2002
NACE SP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems	2007
NEI 09-14	Guideline for the Management of Underground Piping and Tank Integrity	3
	Buried Piping and Tanks Program Basis Document	0
	Miscellaneous MAPPro generated for buried piping and cathodic protection	
	Underground Components Inspection Plan	0

PROCEDURES

NUMBER	TITLE	REVISION
2.1.11.1	Turbine Building Data	138
2.1.11.3	Radwaste and Augmented Radwaste Building Data	88
3.6.5	Excavation and Ground Penetrating Activities	18
3.13.1	Buried Piping and Tank Inspection Program Implementation	3
3.13.1.1	Buried Piping and Tanks Visual Inspection	0
3-EN-DC-343	Underground Piping and Tanks Inspection and Monitoring Program	5C0
6.FP.601	Fire Protection System 31 Day Examination	21

B.1.10 Containment Inservice Inspection Program and Commitments 5, 33, 34, and 35

CONDITION REPORTS (CNS-CR-)

2011-01139	2011-07615	2012-08522	2012-08579	2012-08854

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 3.2	Aging Management Program Evaluation Report – Civil/Structural – Containment Inservice Inspection Program	3
CNS-RPT-13-LRILR-05	B.1.10 Commitments Implementation Review – Containment Inservice Inspection	0
NUREG-1944, Section 3.0.3.2.6	Containment Inservice Inspection Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
Calculation NEDC 94-214	Evaluation of Torus Shell Corrosion and the Impact to Structural Integrity of the Torus	6 and 7
Engineering Change Request 12-047	Evaluate Acceptability of Torus Pits Identified in Bay 8 and Bay 15	0
NUC2010117	Refueling Outage RE26 Reactor Torus Filtration and Desludging, IWE Examination, Coating and Corrosion Inspection Coating Repair	0
NUC2012108	Refueling Outage RE27 Reactor Torus Filtration and Desludging, IWE Examination, Coating and Corrosion Inspection Coating Repair	0
Work Order 4829879	Drywell Sand Cushion Drain Vacuum Test	July 12, 2012
	Cooper Station 2nd Interval Containment Inspection Program	

PROCEDURES

NUMBER	TITLE	REVISION
3-EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2C1
SP11-002	Drywell Sand Cushion Drain Vacuum Test	1

B.1.12 Diesel Fuel Monitoring Program and Commitment 6

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Diesel Fuel Monitoring	3
CNS-RPT-13-LRILR-06	B.1.12 Commitments Implementation Review Diesel Fuel Monitoring	0
NUREG-1944, Section 3.0.3.2.8	Diesel Fuel Monitoring Program	September 1, 2010

MAINTENANCE DOCUMENTS

12746	14441	36925	36928	53721
53722	61202	72463	4839550	4839551

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
ASTM D4057	Standard Practice for Manual Sampling of Petroleum and Petroleum Products1	1995
CED 6033580	Emergency Diesel Generator Day Tank Fuel Oil Sample Points	0
SIR-04-159, LAW-04-002	API 570 Inspection Report – Diesel Fuel Oil Tank “A”	April 18, 2005
SIR-04-158, LAW-04-001	API 570 Inspection Report – Diesel Fuel Oil Tank “B”	April 18, 2005

PROCEDURES

NUMBER	TITLE	REVISION
3.4.5	Diesel Fuel Oil Tank Erosion Rate Assessment	20
6.DG.601	Diesel Fuel Oil Day Tank Particulate Contamination Test	16
6.FP.612	Diesel Fire PuFuel Quality Test	10
7.0.4	Conduct of Maintenance	37

UPDATED SAFETY ANALYSIS REPORT CHANGES

NUMBER	TITLE	REVISION
UCR 2012-015	Diesel Day Tank Single Low Point Sample Location	0
UCR 2013-035	Delete Duplicate Surveillance Bullet	0

B.1.14 External Surfaces Monitoring Program and Commitment 7

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.3	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, External Surfaces Monitoring	3
CNS-RPT-13-LRILR-07	B.1.14 Commitments Implementation Review External Surfaces Monitoring	0
NUREG-1944, Section 3.0.3.2.9	External Surfaces Monitoring Program	September 1, 2010

PROCEDURES

NUMBER	TITLE	REVISION
EN-DC-178	System Walkdowns	4CO
7.0.13	Control of Insulation Removal and Installation	17
0-EN-LI-102	Corrective Action Process	20C3

MISCELLANEOUS

NUMBER	TITLE	DATE
EN-DC-178 Att. 9.2	SWP Room and Control Building Basement Walkdown	September 23, 2013
EN-DC-178 Att. 9.2	DG1 and DG2 In Service Walkdown	October 3, 2013
EN-DC-178 Att. 9.2	125 and 250 VDC Battery and Charger Rooms Walkdown	October 3, 2013
EN-DC-178 Att. 9.2	T-882-RFP Room Walkdown	September 30, 2013
EN-DC-178 Att. 9.2	T-882 N, RFP Room, T-903 Corridor, T909 Heater Bay Walkdown	September 30, 2013
EN-DC-178 Att. 9.2	Heat Exchanger Rooms and Quads Walkdown	September 27, 2013
EN-DC-178 Att. 9.2	HPCI Room and Southwest Quad Walkdown	September 27, 2013

B.1.15 Fatigue Monitoring Program and Commitment 8

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 4.7	Aging Management Program Evaluation Report – Class 1 Mechanical Fatigue Monitoring Program	2

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-13-LRILR-04	B.1.15 Commitments Implementation Review Fatigue Monitoring Program	2
NUREG-1944, Section 3.0.3.2.10	Fatigue Monitoring Program	September 1, 2010

INSPECTIONS

NUMBER	TITLE	DATE
B9.21.0020.RI	Component Summary RSA-BJ-7x, Pipe-to-Elbow	November 5, 2012
B9.21.0021.RI	Component Summary RSA-BJ-8x, Elbow-to-Pipe	November 5, 2012

MISCELLANEOUS

TITLE
2012 Fatigue Monitoring Report
EE 10-023, “Reactor Pressure Boundary Components Fatigue Management Plan,” Revision 1
Procedure 3.20, Reactor Pressure Vessel And Torus Thermal Transient Review, Revisions 18, 19, and 20

B.1.16 Fire Protection Program and Commitment 9

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.4.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Fire Protection	3
CNS-RPT-13-LRILR-08	B.1.16 Commitments Implementation Review Fire Protection	0
NUREG-1944, Section 3.0.3.2.11	Fire Protection Program	September 1, 2010

MAINTENANCE PLANS (8000000)

03836	10465	41151	41152	41381	41440

PROCEDURES

NUMBER	TITLE	REVISION
6.FP.103	Diesel Fire Pump Inspection	17

PROCEDURES

NUMBER	TITLE	REVISION
6.FP.103	Diesel Fire Pump Inspection	17
6.FP.203	Fire Damper Assembly Examination (Fire Protection System 18 Month Examination)	10

B.1.17 Fire Water Program and Commitment 10

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD08, Section 4.4.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Fire Water System	3
CNS-RPT-13-LRILR-09	B.1.17 Commitments Implementation Review Fire Water System	2
NUREG-1944, Section 3.0.3.2.12	Fire Water System Program	September 1, 2010

MAINTENANCE PLANS (8000000)

10479	10480	39202	39292	39261	41135	41136
41153	41154	41171	41172	41173	41174	

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
Information Notice 2013-06	Corrosion in Fire Protection Piping Due to Air and Water Interaction	March 22, 2013
PBD-MIC	Microbiologically Influenced Corrosion Program Basis Document	1
	Fire Protection Sprinkler Systems for Replacement Spread Sheet (Based on Appendix B of DCD-11)	April 11, 2011
	Condition Report 2012-10009	
	Recurring Task 41971	

PROCEDURES

NUMBER	TITLE	REVISION
3.47.31	Periodic Surveillance and Preventative Maintenance Program	0
3.47.34	Selective Leaching Program	1
6.FP.302	Automatic Deluge and Pre-Action Systems Testing	24

PROCEDURES

NUMBER	TITLE	REVISION
3.47.31	Periodic Surveillance and Preventative Maintenance Program	0
6.FP.603	Fire Hose Station Annual Examination	10
7.04	Conduct of Maintenance	37

WORK ORDERS

4797573 4797574 4797575 4797576

B.1.18 Flow-Accelerated Corrosion Program and Commitment 11

CONDITON REPORTS (CNS-CR-)

2006-08712 2007-01210

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.5	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Flow-Accelerated Corrosion	3
CNS-RPT-13-LRILR-10	B.1.18 Commitments Implementation Review Flow-Accelerated Corrosion	1
NUREG-1944, Section 3.0.3.2.13	Flow-Accelerated Corrosion Program	September 1, 2010

MISCELLANEOUS

TITLE

Erosion Corrosion Examination Checklist for Work Order 4547682

Wear Rate Evaluation for DR-E-14-2827-1, dated November 2001

UT Wear Calculation Rates Evaluation for MS-E-1-X2841-210, dated November 2006

Wear Rate Analysis for DV1 Extraction Steam Piping, dated March 2007

Wear Rate Evaluation for BS-E-28-2812-1, dated April 2008

Wear Rate Evaluation for BS-E-27-2812-1, dated May 2008

Wear Rate Evaluation for BS-O-4-2812-1, dated May 2008

Wear Rate Evaluation for BS-R-3-2812-1, dated May 2008

Wear Rate Evaluation for BS-R-4-2812-,1 dated May 2008

Self-Assessment dated August 2006

PROCEDURES

NUMBER	TITLE	REVISION
3-EN-DC-315	Flow Accelerated Corrosion Program	6C0
3.10	Flow Accelerated Corrosion (FAC) and Microbiologically Influenced Corrosion (MIC) Program Implementation	13

B.1.20 Inservice Inspection – IWF Program and Commitments 12 and 30

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD08, Section 3.5	Aging Management Program Evaluation Report – Civil/Structural, Inservice Inspection – IWF Program	3
CNS-RPT-13-LRILR-11	B.1.20 Commitments Implementation Review Inservice Inspection – IWF Program	2
NUREG-1944, Section 3.0.3.2.15	Inservice Inspection – IWF Program	September 1, 2010

PROCEDURES

NUMBER	TITLE	REVISION
0.30	ASME Section XI Repair/Replacement and Temporary Code and Non-Code Repair Procedure	26
3.28.1	Inservice Inspection Program Implementation	17

B.1.21 Masonry Wall Program and Commitment 13

CONDITON REPORTS (CNS-CR-)

2013-07465 2013-07476

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD08, Section 3.4	Aging Management Program Evaluation Report – Civil/Structural, Masonry Wall Program	3
CNS-RPT-13-LRILR-12	B.1.21 Commitments Implementation Review Masonry Wall Program	0
NUREG-1944, Section 3.0.3.2.16	Masonry Wall Program	September 1, 2010

PROCEDURE

NUMBER	TITLE	REVISION
EN-DC-150	Condition Monitoring of Maintenance Rule Structures	2C1

B.1.22 Metal-Enclosed Bus Inspection Program and Commitment 14

CONDITION REPORTS (CNS-CR-)

2009-03704 2009-03705 2009-03752 2009-03753 2005-03946 2009-03975

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD09, Section 3.1	Aging Management Program Evaluation Report – Electrical, Metal-Enclosed Bus Inspection Program	4
CNS-RPT-10-LRIER-04	Metal-Enclosed Bus Inspection Program Implementation Report	0
CNS-RPT-13-LRILR-13	B.1.22 Commitments Implementation Review Metal-Enclosed Bus Inspection Program	0
NUREG-1944, Section 3.0.3.2.17	Metal-Enclosed Bus Inspection Program	September 1, 2010

PREVENTATIVE MAINTENANCE

19968 20628 36042

PROCEDURES

NUMBER	TITLE	REVISION
3.47	License Renewal Implementation Program	0
7.3.41	Examination and Meggering of Non-Segregated Buses and Associate Equipment	9

Work Orders

4458028 4699195 4699196 4442920 4416692 4442409 4878650

B.1.23 Neutron Absorber Monitoring Program and Commitment 31

CONDITION REPORTS (CNS-CR-)

2012-08268 2012-02989

LETTERS

NUMBER	TITLE	DATE
NLS2009055	Response to Request for Additional Information for License Renewal Application	July 29, 2009
NLS2009095	Response to Request for Additional Information for License Renewal Application	November 30, 2009
NLS2010019	Supplemental Information for the Review of Cooper Nuclear Station License Renewal Application	March 25, 2010

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 3.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Neutron Absorber Monitoring Program	3
CNS-RPT-13-LRILR-25	B.1.23 Commitments Implementation Review Neutron Absorber Monitoring	0
NUREG-1944, Section 3.0.3.3.1	Neutron Absorber Monitoring Program	September 1, 2010

MAINTENANCE DOCUMENTS

11561	76608	4663696

MISCELLANEOUS

TITLE
Procedure 10.20, “Boral Coupon Sampling,” Revision 16
Summary of Telephone Conference Call Held on January 8, 2010, between the US Nuclear Regulatory Commission Staff and Nebraska Public Power District Related to Clarifications for Certain Responses to Requests for Additional Information for Cooper Nuclear Station License Renewal, dated February 3, 2010

B.1.24 Non-Environmentally Qualified Bolted Cable Connection Program and Commitment 15

CONDITION REPORTS (CNS-CR-)

2009-06294	2010-01638	2010-02172	2010-02241	2010-04312
2010-08305	2011-02025	2011-03124	2012-01638	2012-01973
2012-02068	2012-02151	2012-02653	2012-03411	2012-08637
2013-02842	2013-02857			

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD09, Section 3.2	Aging Management Program Evaluation Report – Electrical, Non-Environmentally Qualified Bolted Connections Program	4
CNS-RPT-10-LRIER-06	Non-Environmentally Qualified Bolted Connections Program - One-Time Program Report	0
CNS-RPT-13-LRILR-15	B.1.24 Commitments Implementation Review Non-Environmentally Qualified Bolted Connections Program	0
NUREG-1944, Section 3.0.3.3.2	Non-Environmentally Qualified Bolted Connections Program	September 1, 2010

PROCEDURES

NUMBER	TITLE	REVISION
7.3.14	Thermal Examination of Plant Components	8
7.3.20.3	Motor Analysis	18
7.3.28.1	Lead Removal/Installation and Lug Installation	29

WORK ORDERS

4624878	4648007	4664359	4664543	4763203
4750998	4760423	4694523	4845182	4802612
4802613	4847751	4868441	4934899	4860934

B.1.25 Non-Environmentally Qualified Inaccessible Medium-Voltage Cables Program and Commitment 16

CONDITON REPORTS CNS-CR-)

2009-05839	2011-06568	2011-07615	2012-07428	*2013-07532	*2013-07564

DRAWING

NUMBER	TITLE	REVISION
3190	Cooper Nuclear Station Underground Duct Banks Plan	N01
3191 Sheet 1	Cooper Nuclear Station Underground Duct Banks Plan, Sections, and Details	N01

DRAWING

NUMBER	TITLE	REVISION
3192 Sheet 2	Cooper Nuclear Station Underground Duct Banks Plan, Sections and Details	3
4016 Sheet 1	Cooper Nuclear Station Structural Electrical Manholes	N01
3193	Cooper Nuclear Station Underground Duct Banks Sections and Details	4
4226	Structural Miscellaneous Concrete Details	N01
3180 Sheet 1	Cooper Nuclear Station Duct Banks Plan, Sections and Details	N11
3182 Sheet 2	Duct banks Plan, Sections, and Details	N04
3189	Cooper Nuclear Station Underground Duct Banks Profiles and Sections	N02
3194	Cooper Nuclear Station Duct Bank Cable Schedule	N10

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD09, Section 3.3	Aging Management Program Evaluation Report Electrical, Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program	4
CNS-RPT-10-LRIER-03	Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program	0
CNS-RPT-13-LRILR-19	B.1.25 Commitments Implementation Review Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program	0
NUREG-1944, Section 3.0.3.1.7	Non-Environmentally Qualified Inaccessible Medium-Voltage Cable Program	September 1, 2010

MAINTENANCE PLANS (8000000)

07959	07981	10056	10057	21737
21741	21742	21753	36501	36732
36733	36734	36735	36736	36737
36738	36739	36740		

MISCELLANEOUS

NUMBER	TITLE	REVISION
CED 6034320	Electrical Manhole 6 and 6A Level Switch and Alarm Installation	0
Procedure 3.47.25	Non-EQ Inaccessible Power Cables Program	3

WORK ORDERS

4179100	4338356	4498670	4664229	4166747
4324194	485533	4664230		

B.1.26 Non-Environmentally Qualified Instrumentation Circuits Test Review Program and Commitment 17

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD09, Section 3.4	Aging Management Program Evaluation Report – Electrical, Non-Environmentally Qualified Instrumentation Circuits Test Review Program	4
CNS-RPT-10-LRIER-02	Non-Environmentally Qualified Instrumentation Circuits Test Review Program	0
CNS-RPT-13-LRILR-16	B.1.26 Commitments Implementation Review Non-Environmentally Qualified Instrumentation Circuits Test Review Program	0
NUREG-1944, Section 3.0.3.1.8	Non-Environmentally Qualified Instrumentation Circuits Test Review Program	September 1, 2010

MISCELLANEOUS

TITLE
Condition Report 2012-10009
Maintenance Plan 039175

PROCEDURES

NUMBER	TITLE	REVISION
3.47.26	Non-EQ Sensitive Instrumentation Circuits Test Review Program	0
3.47	License Renewal Implementation Program	0

B.1.27 Non-Environmentally Qualified Insulated Cables and Connections Program and Commitment 18

CONDITION REPORTS (CNS-CR-)

2009-10340 2009-10632 2010-00110 2010-00115 2010-00124 2010-00203

2011-05974

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD09, Section 3.5	Aging Management Program Evaluation Report – Electrical, Non-Environmentally Qualified Insulated Cables and Connections Program	4
CNS-RPT-10-LRIER-01	Non-Environmentally Qualified Insulated Cables and Connections Program	0
CNS-RPT-13-LRILR-17	B.1.27 Commitments Implementation Review Non-Environmentally Qualified Insulated Cables and Connections Program	0
NUREG-1944, Section 3.0.3.1.9	Non-Environmentally Qualified Insulated Cables and Connections Program	September 1, 2010

MAINTENANCE PLANS (8000000)

039751 039752

PROCEDURE

NUMBER	TITLE	REVISION
3.47.27	Non-EQ Insulated Cables and Connections Aging Management Program	0

WORK ORDERS

4728107 4817042

B.1.28 Oil Analysis Program and Commitment 19

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.7	Aging Management Program Evaluation Report – Non-Class 1 Mechanical Oil Analysis	3
CNS-RPT-13-LRILR-18	B.1.28 Commitments Implementation Review Oil Analysis	0

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
NUREG-1944, Section 3.0.3.2.18	Oil Analysis Program	September 1, 2010
	Response to Request for Additional Information for the Review of Cooper Nuclear Station License Renewal Application	November 30, 2009

PROCEDURES

NUMBER	TITLE	REVISION
3.47.31	Periodic Surveillance and Preventive Maintenance Program	0
7.0.14.2	Lubrication/Oil Analysis Program	8

UPDATED SAFETY ANALYSIS REPORT CHANGES

NUMBER	TITLE	REVISION
UCR 2013-027	Delete Flash Point from Enhancements to Oil Analysis Program	0
UCR 2013-032	Revise Numerous Sections in the Updated Safety Analysis Report Supplement to Reflect Implementation of Aging Management Programs	0

B.1.29 One-Time Inspection Program and Commitment 20

CONDITION REPORS (CNS-CR-)

2009-07726 2009-08546 2012-07526 2012-07869

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 3.4	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, One-Time Inspection	3
CNS-RPT-13-LRILR-20	B.1.29 Commitments Implementation Review One-Time Inspection Program	0
CNS-RPT-13-LRIMR-05	Mechanical One-Time Inspection Program – Readiness Report	0
NUREG-1944, Section 3.0.3.1.10	One-Time Inspection Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION
Calculation NEDC 12-023	Mechanical One-Time Inspection Program Minimum Wall Determination	0

MISCELLANEOUS

NUMBER	TITLE	REVISION
Calculation 13-012	Flaw Tolerance Reactor Recirculation Flow Element	0

MISCELLANEOUS

TITLE
Mechanical One-Time Inspection Program inspection results evaluation for Piping Segment REC-P-1-2848-7
Mechanical One-Time Inspection Program Summary Report for RE27, dated April 11, 2013
Status Summary List of Mechanical One-Time Inspections

ONE-TIME INSPECTIONS (WO)

4475991	4625195	4664559	4733748	4745071	4833696

PROCEDURES

NUMBER	TITLE	REVISION/DATE
3.10	Flow Accelerated Corrosion (FAC) and Microbiologically Influenced Corrosion (MIC) Program Implementation	13
3.47.29	Mechanical One-Time Inspection Program	0

B.1.30 One-Time Inspection – Small-Bore Piping Program and Commitments 21 and 32

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 3.1	Aging Management Program Evaluation Report – Class 1 Mechanical, One-Time Inspection – Small Bore Piping Program	2
CNS-RPT-13-LRILR-21	B.1.30 Commitments Implementation Review One-Time Inspection- Small-Bore Piping	0
CNS-RPT-13-LRIMR-06	One-Time Inspection- Small-Bore Piping Program Report	0
NUREG-1944, Section 3.0.3.1.11	One-Time Inspection – Small Bore Piping Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
18.18036.01.140	Investigation of Cracked Small-Bore Diameter Pipe in the Residual Heat Removal Drain Line LOOP A	March 2004

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
CNS-LO-2013-00519	Tracking form for future socket weld ultrasonic test evaluations	
Procedure 3.28.UT.SOC	Socket Weld Ultrasonic Phased Array Weld Examination	0

SMALL BORE PIPE INSPECTIONS

B9.21.0020.RI Component Summary RSA-BJ-7x, Pipe-to-Elbow

B9.21.0021.RI Component Summary RSA-BJ-8x, Elbow-to-Pipe

B9.21.0022.RI Component Summary RSA-BJ-9, Pipe-to-Elbow

B9.21.0002.RI Component Summary RSA-BJ-10, Elbow-to-Elbow

B9.40.0014.RI Component Summary RVD-BJ-10, Pipe-to-Elbow

B9.21.0032.RI Component Summary RSA-BJ-17, Pipe-to-Elbow

B9.21.0033.RI Component Summary RSA-BJ-18, Pipe-to-Elbow

B9.40.0169.RI Component Summary SLC-BJ-8, Pipe-to-Elbow

B9.40.0170.RI Component Summary SLC-BJ-9, Pipe-to-Elbow

B.1.31 Periodic Surveillance and Preventive Maintenance Program and Commitment 22

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.8	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Periodic Surveillance and Preventive Maintenance	3
CNS-RPT-13-LRILR-23	B.1.31 Commitments Implementation Review Periodic Surveillance and Preventive Maintenance	0
CNS-RPT-13-LRIMR-07	Periodic Surveillance and Preventive Maintenance Program – Readiness Report	0
NUREG-1944, Section 3.0.3.3.3	Periodic Surveillance and Preventive Maintenance Program	September 1, 2010

MAINTENANCE PLANS (8000000)

04191 04192 04193 04194

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION/DATE
	Condition Report 2010-00744	
	Maintenance Personnel Training Records	October 24, 2013
MNT2060000	Training Manual Identification and Detection of Aging Issues	1
ESP0300607	Training Manual Identification and Detection of Aging Issues	0
103	Training Program Procedure Maintenance Personnel	21

PROCEDURES

NUMBER	TITLE	REVISION
3.47.31	Periodic Surveillance and Preventative Maintenance Program	0
7.02	Preventative Maintenance Program Implementation	52

B.1.33 Reactor Vessel Surveillance Program and Commitment 23

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 4.10	Aging Management Program Evaluation Report – Class 1 Mechanical, Reactor Vessel Surveillance	3
CNS-RPT-13-LRILR-22	B.1.33 Commitments Implementation Review Reactor Vessel Surveillance	0
NUREG-1944, Section 3.0.3.2.5	Reactor Vessel Surveillance Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
2001-231	NRC Safety Evaluation of BWRVIP-116 (Integrated Surveillance Program Implementation for License Renewal)	April, 10, 2006
EPRI 1007824	BWRVIP-116: BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal	July 2003
Procedure 3.28.4	Integrated Surveillance Program	11
USAR Change Request 2013-032	Revise Numerous Sections in the Updated Safety Analysis Report Supplement to Reflect Implementation of Aging Management Programs	0

B.1.34 Selective Leaching Program and Commitment 24

CONDITON REPORTS (CNS-CR-)

2010-05957	2010-06775	2011-05932	2011-11363	2011-11387
2012-01237	2012-02341	2012-04446	2012-05509	2012-05721
2013-00047	2013-01574	2013-02728	2013-03894	2013-03899

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-LRPG-17	License Renewal Project Guidelines, Attachment 4 – Inspection Site Selection Checklist	1
CNS-RPT-07-LRD07, Section 3.5	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Selective Leaching	3
CNS-RPT-13-LRILR-24	B.1.34 Commitments Implementation Review Selective Leaching Program	0
CNS-RPT-13-LRIMR-08	Selective Leaching Program - Readiness Report	0
NUREG-1944, Section 3.0.3.1.12	Selective Leaching Inspection Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	DATE
	Final Report on Selective Leaching (Graphitic Corrosion) of Gray Iron Valves and Fittings at NPPD Cooper Nuclear Station	December 21, 2011
	Reviewed sample selection process for all material-environment combinations within the selective leaching program	

PROCEDURES

NUMBER	TITLE	REVISION
3.47.34	Selective Leaching Program	0
8.3	Control Parameters and Limits	67
8.3VIP	Vessel Internals Protection Control Parameters and Limits	7

WORK ORDERS

4834186	4834189	4834192

B.1.36 Structures Monitoring Program and Commitment 25

CONDITON REPORTS (CNS-CR-)

2012-01597	2009-03194	2012-08680	2009-03188

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD08, Section 3.3	Aging Management Program Evaluation Report – Civil/Structural, Structures Monitoring Program	3
CNS-RPT-13-LRILR-14	B.1.36 Commitments Implementation Review Structures Monitoring Program	0
NUREG-1944, Section 3.0.3.2.20	Structures Monitoring Program	September 1, 2010

MISCELLANEOUS

TITLE
American Concrete Institute (ACI) 201.1R-92, Guide for Making a Condition Survey of Concrete in Service (Reapproved 1997)
ACI 349.3R-96, Evaluation of Existing Nuclear Safety-Related Concrete Structures
Calculation NEDC 96 20, “Structural Inspections of CNS Structures,” Revision 4
CED 6035942, “Service Water PuRoom Instrument Rack Replacements,” dated August 2013
Control Building Roof Inspection Report 13-16, dated August 1, 2013
Main Transformer Pad Foundation Inspection Report, dated October 23, 2012
Groundwater Sample Results for GMW-2, -8, and -10 from 2006 and 2012
Structural Walk-down Inspection Reports from 1996, 2007, and 2012

PROCEDURES

NUMBER	TITLE	REVISION
3-EN-DC-150	Condition Monitoring of Maintenance Rule Structure	C21
3.6.5	Excavation and Ground Penetrating Activites	18
8.ENV.9	Ground Water Monitoring Program Sampling, Monitoring, and Administrative Requirements	9

B.1.37 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel and Commitment 29

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 3.2	Aging Management Program Evaluation Report – Class 1 Mechanical, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program	2
CNS-RPT-11-LRILR-02	B.1.37 Commitments Implementation Review - Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program	1
NUREG-1944, Section 3.0.3.1.14	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
	Cooper Nuclear Station Vessels Internal Program	19.9
BWRVIP-234	Thermal Aging and Neutron Embrittlement Evaluation of Cast Austenitic Stainless Steels for BWR Internals	December 2009
EE 11-045	Reactor Vessel Internals CASS Material Review	0
NUREG/CR-4513	Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems	1

Aging Management Programs without Commitments

B.1.4 BWR Control Rod Drive Return Line Nozzle Program

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 4.1	Aging Management Program Evaluation Report – Class 1 Mechanical, BWR CRD Return Line Nozzle	2
CNS-RPT-07-LRD05, Section 4.1.1	Operating Experience Review Report – BWR CRD Return Line Nozzle Program	2
NUREG-1944, Section 3.0.3.1.3	Boiling Water Reactor Control Rod Drive Return Line Nozzle Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	DATE
LQA8100051	Response to NUREG 0619-BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking	January 7, 1981
LQA8100068	Response to Unresolved Safety Issue A-10, BWR Nozzle Cracking	September 22, 1981
MDC 77-100	Control Rod Drive Return Line Nozzle Capping and Inspection	September 9, 1977
MDC 79-065	Replacement of Carbon Steel Pipe and Installation of Equalizing Valves in the Control Rod Drive System	August 29, 1979

PROCEDURES

NUMBER	TITLE	REVISION
0.30	ASME Section XI Repair/Replacement and Temporary Code and Non-Code Repair Procedure	26
0-QA-01	CNS Quality Assurance Program	16
3.28.1	Inservice Inspection Program Implementation	17
	Condition Report 2011-04254	

ULTRASONIC EXAMINATIONS

NUMBER	COMPONENT	DESCRIPTION
1-CNS-RCA-BF-1	RCA-BF-1	Control Rod Drive Cap
VE-2011-116	NVE-BD-N9	Control Rod Drive to Reactor Pressure Vessel Nozzle to Shell Weld
VE-2011-040	NVIR-BD-N9	Control Rod Drive to Reactor Pressure Vessel Nozzle Inner Radius Section

B.1.5 Boiling Water Reactor Feedwater Nozzle Program

LICENSE RENEWAL

NUMBER	TITLE	REVISION/DATE
CNS-RPT-07-LRD02, Section 4.2	Aging Management Program Evaluation Report – Class 1 Mechanical, BWR Feedwater Nozzle	2
CNS-RPT-07-LRD05, Section 4.1.2	Operating Experience Review Report – BWR Feedwater Nozzle Program	2
NUREG-1944, Section 3.0.3.2.2	Boiling Water Reactor Feedwater Nozzle Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
GE-NE-523-A71-0594	Alternate BWR Feedwater Nozzle Inspection Requirements	August 1999
LQA8100051	Response to NUREG 0619-BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking	January 7, 1981
NUREG-0619	BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking: Resolution of Generic Technical Activity A-10	1

ULTRASONIC EXAMINATIONS

NUMBER	COMPONENT	DESCRIPTION
A11.1.FWBA.045	NB/NB-N4A	Feedwater Nozzle Bore
B3.100.0017	NB/NVIR-BD-N4A	Reactor Pressure Vessel Nozzle Inner Radius Section
B3.100.0018	NB/NVIR-BD-N4B	Reactor Pressure Vessel Nozzle Inner Radius Section
B3.100.0019	NB/NVIR-BD-N4C	Reactor Pressure Vessel Nozzle Inner Radius Section
B3.100.0020	NB/NVIR-BD-N4D	Reactor Pressure Vessel Nozzle Inner Radius Section
B3.90.0017	NB/NVE-BD-N4A	Reactor Pressure Vessel Nozzle to Shell Weld
B3.90.0018	NB/NVE-BD-N4B	Reactor Pressure Vessel Nozzle to Shell Weld
B3.90.0019	NB/NVE-BD-N4C	Reactor Pressure Vessel Nozzle to Shell Weld
B3.90.0020	NB/NVE-BD-N4D	Reactor Pressure Vessel Nozzle to Shell Weld

B.1.6 Boiling Water Reactor Penetrations Program

LICENSE RENEWAL

NUMBER	TITLE	REVISION/DATE
CNS-RPT-07-LRD02, Section 4.3	Aging Management Program Evaluation Report – Class 1 Mechanical, BWR Penetrations	2
CNS-RPT-07-LRD05, Section 4.1.3	Operating Experience Review Report – BWR Penetrations Program	2
NUREG-1944, Section 3.0.3.1.4	Boiling Water Reactor Penetrations Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
	Cooper Nuclear Station Vessel Internals Program, Section 12.4, BWRVIP-27-A, "BWRVIP Standby Liquid Control System/Core Spray/ Core Plate ΔP Inspection and Flaw Evaluation Guidelines," and Section 12.9, BWRVIP-49-A," Instrument Penetration Inspections"	19.9
	Fourth 10-Year Interval Inservice Inspection Program for Cooper Nuclear Station	2.9
Letter G-HPO-2-226	ASME Code Section XI Pipe Exclusion – Revised Analysis	December 11, 1992

ULTRASONIC EXAMINATION

NUMBER	COMPONENT	DESCRIPTION
VE-F12-001	SLC-BJ-1	Standby Liquid Control to Vessel Dissimilar Metal Weld

B.1.7 Boiling Water Reactor Stress Corrosion Cracking Program

LICENSE RENEWAL

NUMBER	TITLE	REVISION/DATE
CNS-RPT-07-LRD02, Section 4.4	Aging Management Program Evaluation Report – Class 1 Mechanical, BWR Stress Corrosion Cracking Program	2
CNS-RPT-07-LRD05, Section 4.1.4	Operating Experience Review Report – BWR Stress Corrosion Cracking Program	2
NUREG-1944, Section 3.0.3.2.3	Boiling Water Reactor Stress Corrosion Cracking Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
NLS2009006	Relief Request RI-21 & Relief Request RI-22, Inservice Inspection Impracticality	February 16, 2009
	Condition Report 2008-03253	
	Cooper Nuclear Station Vessel Internals Program, Section 12.24, VIP-75, Technical Basis for Revision to Generic Letter 88-01 Inspection Schedules	19.9
	Fourth Ten-Year Interval Inservice Inspection Program for Cooper Nuclear Station	2.9

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
	SER Approving Relief Request RI-21 & Relief Request RI-22	January 12, 2010

PROCEDURES

NUMBER	TITLE	REVISION
2.2.98	OWC Gas Generation And Injection System	19
8.3	Control Parameters and Limits	67
8.12.2	Mitigation Monitoring System (MMS)	11

ULTRASONIC EXAMINATIONS

NUMBER	DESCRIPTION	DATE
B5.10.0001.RI	CSA-BF-1x (N5A), Safe End to Nozzle	April 30, 2008
B5.10.0004.RI	JPB-BF-1, Reactor Pressure Vessel Nozzle to Safe End	January 27, 2005
B5.10.0012.RI	RRE-BF-1 (N2E), Safe End to Nozzle	April 29, 2008
B5.10.0015.RI	RRH-BF-1 (N2H), Safe End to Nozzle	April 29, 2008
B5.10.0017.RI	RRH-BF-1 (N2K), Safe End to Nozzle	May 8, 2008
B5.130.0002.RI	CSB-BF-4A, Pipe to Elbow Dissimilar Metal Weld	April 25, 2008
B5.130.0003.RI	RAD-BF-7 (RHR), Pipe to Elbow Dissimilar Metal Weld	January 27, 2005
B5.130.0004.RI	RAS-BF-12, Pipe to Elbow Dissimilar Metal Weld	April 29, 2008
UT-S08-002	CSA-BJ-2x, Pipe 90 to Safe-End	April 26, 2008
UT-S08-004	RRE-BJ-2, Bent Pipe 90 to Safe-End	April 29, 2008
UT-S08-005	RRH-BJ-2, Bent Pipe 90 to Safe-End	April 29, 2008
UT-S08-006	RRK-BJ-2, Bent Pipe 90 to Safe-End	April 29, 2008
UT-2011-007	RAD-BJ-4, Bent Pipe 90 to Custom Manufactured Tee	April 9, 2011
UT-2011-009	CWA-BJ-2, Bent Pipe 90 to Bent Pipe 90	April 9, 2011
UT-2011-010	CWA-BJ-3, Bent Pipe 90 to Bent Pipe 90	April 12, 2011
UT-2011-012	RRE-BJ-3, Pipe to Pipe	April 12, 2011
UT-2011-013	RRE-BJ-4, Pipe to Bent Pipe 90	April 12, 2011

B.1.8 Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program

DRAWINGS

NUMBER	TITLE	REVISION
232-247	Reactor Vessel Internal Attachments	7
919D690BC, Sh 4	Reactor Vessel Internal Attachment Details	0

LICENSE RENEWAL

NUMBER	TITLE	REVISION/DATE
CNS-RPT-07-LRD02, Section 4.5	Aging Management Program Evaluation Report – Class 1 Mechanical, BWR Stress Corrosion Cracking	2
CNS-RPT-07-LRD05, Section 4.1.5	Operating Experience Review Report – BWR Vessel Inside Diameter Attachment Welds Program	2
NUREG-1944, Section 3.0.3.1.5	Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION
	Cooper Nuclear Station Vessel Internals Program, Section 12.8, VIP-48, Vessel Inside Diameter Attachment Welds	19.9
	Fourth Ten-Year Interval Inservice Inspection Program for Cooper Nuclear Station	2.9

ULTRASONIC EXAMINATIONS

NUMBER	COMPONENT	DESCRIPTION
VT-F12-075	STMDRY-HLDDWNBKT-ATTWLDS@215	Steam Dryer Hold Down Bracket Attachment Weld to Reactor Pressure Vessel Top
VT-F12-077	STMDRY-HLDDWNBKT-ATTWLDS@325	Steam Dryer Hold Down Bracket Attachment Weld to Reactor Pressure Vessel Top
VT-F12-078	STMDRY-HLDDWNBKT-ATTWLDS@35	Steam Dryer Hold Down Bracket Attachment Weld to Reactor Pressure Vessel Top
VT-F12-079	STMDRY-HLDDWNBKT-ATTWLDS@145	Steam Dryer Hold Down Bracket Attachment Weld to Reactor Pressure Vessel Top

B.1.11 Containment Leak Rate Program

COMPLETED LEAK RATE TESTS

NUMBER	TITLE	DATE
6.PC.519	Reactor Core Isolation Coolant (RCIC) Local Leak Rate Tests (Penetration X-212)	October 26, 2012
6.PC.522	Standby Nitrogen Injection and Primary Containment Purge and Vent Systems Local Leak Rate Tests (Penetration X-26)	November 2, 2012
6.PC.522	Standby Nitrogen Injection and Primary Containment Purge and Vent Systems Local Leak Rate Tests (Penetration X-220)	November 3, 2012
6.PC.523	Expansion Bellows Local Leak Rate Tests	March 29, 2011
6.PC.526	Service Air Local Leak Rate Tests	October 29, 2012

GUIDANCE

NUMBER	TITLE	REVISION/DATE
ANSI/ANS-56.8	Containment System Leakage Testing Requirements	2002
BN-TOP-1	Testing Criteria of Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants, Bechtel Power Corporation	1
NEI 94-01	Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J	2A
OG96-320-112	Appendix J – Generic Letter 89-10 Correlation – *Retest Requirement Guidelines for Appendix J Valves*	April 30, 1996
Regulatory Guide 1.163	Performance Based Containment Leak-Test Program	1

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD08, Section 3.1	Aging Management Program Evaluation Report – Civil/Structural, Containment Leak Rate Program	3
CNS-RPT-07-LRD05, Section 4.1.8	Operating Experience Review Report – Containment Leak Rate Program	2
NUREG-1944, Section 3.0.3.2.7	Containment Leak Rate Program	September 1, 2010

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
Amendment 38	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	July 22, 1994
Amendment 234	Cooper Nuclear Station – Exemption from the Requirements of 10 CFR Part 50, Appendix J	September 14, 2009
Drawing 2022, Sheet 1	Flow Diagram – Primary Containment Cooling & Nitrogen Inerting System	78
Drawing 54051	Streamseal Valve Drawing	2A
Letter	Leakage Rate of 20" & 24" Rubber Seated STREAMSEAL Butterfly Valves	September 15, 1987
NEDC 07-041	Review of Entergy License Renewal Services Group Report "CNS-RPT-07-LRD08 - Aging Management Program Evaluation Results - Civil/Structural"	0
	Primary Containment Leakage Rate Testing Program Notebook	11
	Primary Containment Leakage Rate Testing Program Document	18

PROCEDURES

NUMBER	TITLE	REVISION/DATE
3.40	Primary Containment Leakage Rate Testing Program	11
6.PC.501	Primary Containment Local Leak Rate Tests	40
6.PC.504	Primary Containment Integrated Leak Rate Test	11
6.PC.513	Main Steam Local Leak Rate Tests	22
EN-DC-329	Engineering Programs Control and Oversight	4C0

B.1.32 Reactor Head Closure Studs

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD02, Section 4.9	Aging Management Program Evaluation Report – Class 1 Mechanical, Reactor Head Closure Studs	2
CNS-RPT-07-LRD05, Section 4.1.22	Operating Experience Review Report – Reactor Head Closure Studs Program	2

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
NUREG-1944, Section 3.0.2.2.19	Reactor Head Closure Studs Program	September 1, 2010

MISCELLANEOUS

RE20 ISI Examinations Report

PROCEDURES

NUMBER	TITLE	REVISION
0.30	ASME Section XI Repair/Replacement and Temporary Code and Non-Code Repair Procedure	26
3.28.1	Inservice Inspection Program Implementation	17
7.2.71	Bolting and Torque Program	38
7.4DISASSEMBLY	Reactor Vessel Disassembly	4
7.4REASSEMBLY	Reactor Vessel Reassembly	4

B.1.38 Water Chemistry Control – Auxiliary Systems Program

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.10.1	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Water Chemistry Control – Auxiliary Systems Program	3
CNS-RPT-07-LRD05, Section 4.1.27	Operating Experience Review Report – Water Chemistry Control – Auxiliary Systems Program	2
NUREG-1944, Section 3.0.3.3.4	Water Chemistry Control – Auxiliary Systems Program	September 1, 2010

MISCELLANEOUS

TITLE
Heating boiler, chilled water, and condensate storage tank trend graphs for monitored chemistry parameters for the last four years

PROCEDURES

NUMBER	TITLE	REVISION/DATE
8.2.1	Chemistry Analysis Schedule	67
8.3	Chemistry Parameters and Limits	67

B.1.39 Water Chemistry Control – Boiling Water Reactor

CONDITION REPORTS (CNS-CR-)

2009-02089	2009-09388	2009-09390	2009-09430	2011-01026
2011-04911	2011-05151	2011-05193	2011-05719	2012-00433
2012-04346	2012-08997	2012-09903	2012-10009	2012-10242
2012-10249				

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.10.2	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Water Chemistry Control – Boiling-Water Reactor Program	3
CNS-RPT-07-LRD05, Section 4.1.28	Operating Experience Review Report – Water Chemistry Control – Boiling-Water Reactor Program	2
NUREG-1944, Section 3.0.3.1.15	Water Chemistry Control – Boiling-Water Reactor Program	September 1, 2010

PROCEDURES

NUMBER	TITLE	REVISION
8.2.1	Chemistry Analysis Schedule	67
8.3	Chemistry Parameters and Limits	67
0-QA-01	CNS Quality Assurance Program	16
8.3VIP	Vessel Internals Protection Control Parameters and Limits	7
8.12.1	Depleted Zinc Oxide Injection System	11
8.12.2	Mitigation Monitoring System	12
2.2.98	OWC Gas Generation and Injection System	19

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	DATE
BWRVIP-130	BWR Vessel Internals Project BWR Water Chemistry Guidelines	2004
BWRVIP-190	BWR Vessel Internals Project BWR Water Chemistry Guidelines	2008

B.1.40 Water Chemistry Control – Closed Cooling Water Program

CONDITION REPORTS (CNS-CR-)

2009-04827 2013-04401

LICENSE RENEWAL

NUMBER	TITLE	REVISIONDATE
CNS-RPT-07-LRD07, Section 4.10.3	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Water Chemistry Control – Closed Cooling Water Program	3
CNS-RPT-07-LRD05, Section 4.1.29	Operating Experience Review Report – Water Chemistry Control – Closed Cooling Water Program	2
NUREG-1944, Section 3.0.3.2.21	Water Chemistry Control – Closed Cooling Water Program	September 1, 2010

MISCELLANEOUS

TITLE
Reactor equipment cooling, turbine equipment cooling, and diesel generator jacket water trend graphs for monitored chemistry parameters for the last four years

PROCEDURES

NUMBER	TITLE	REVISION
8.2.1	Chemistry Analysis Schedule	67
8.3	Chemistry Parameters and Limits	67

Newly Identified Components

CHANGE EVALUATION DOCUMENTS

NUMBER	TITLE	REVISION
CED 6026860	Main Turbine Lube Oil Conditioner System Upgrade	0
CED 6032580	Installation of RHR Chemical Decontamination Connection Flange	0

ENGINEERING EVALUATIONS

NUMBER	TITLE	REVISION
11-004	69 kV Towers	0
11-018	Use-As-Is Evaluation of Diesel Generator Camshaft Carrier	0

ENGINEERING EVALUATIONS

NUMBER	TITLE	REVISION
	Bearing Bolting	
11-037	Diesel Fuel Oil Tank Erosion Rate Assessment	0
12-023	Extend Expected Live for CNS-9-CRD-SOV-S031A & B Control Rod Drive SCRAM Discharge Volume Vent and Drain Pilot Valves	0
12-045	Evaluation of Undocumented Components Installed on the Diesel Generator Fuel Oil Systems	2

LICENSE RENEWAL

NUMBER	TITLE	REVISION
CNS-RPT-11-LRILR-01	10 CFR 54.37(b) Review for Updated Safety Analysis Report Revision XXV	0
CNS-RPT-13-LRILR-01	10 CFR 54.37(b) Review for Updated Safety Analysis Report Revision XXVI	0

MISCELLANEOUS

TITLE
Condition Report CNS-CR-2012-00744
Notification 10935651
Part Evaluation 4703994, Replace DGJW-CV-10CV/11CV
Verified that the licensee updated the component database to reflect components that required the license renewal flag

Administrative Controls - Commitment Change Process

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
Procedure 3.47	License Renewal Implementation Program	0
	Condition Report 2013-02957	
	Cooper Nuclear Station – Issuance of Amendment RE: Modification of Renewed Operating License Condition 2E	September 12. 2013

UPDATED SAFETY EVALUATION REPORT CHANGE REQUESTS

NUMBER	TITLE	REVISION
2012-003	Revise the One-Time Inspection Program Criteria to Allow “Surface Condition” to Monitor for Loss of Material and Cracking	0
2012-012	Revise Sampling Strategy for Periodic Surveillance Preventive	0

UPDATED SAFETY EVALUATION REPORT CHANGE REQUESTS

NUMBER	TITLE	REVISION
	Maintenance Program	
2012-014	CO_2 Systems Located in Inaccessible Areas	0
2012-015	Diesel Day Tank Single Low Point Sample Location	0
2013-003	Incorporate Table K-4-1, “Consolidated List of License Renewal Commitments”	0
2013-027	Delete Flash Point from Enhancements to Oil Analysis Program	0
2013-029	Revise One-Time Inspection Program to Exclude Main Steam Line and Reactor Recirculation Flow Elements	0
2013-032	Revise Numerous Sections in the Updated Safety Analysis Report Supplement to Reflect Implementation of Aging Management Programs	0
2013-034	Revise Structures Monitoring Program to Characterize Blowout Panels as Structures Enhancements Rather Than Bulk Commodity Enhancements	0
2013-038	Revise Selective Leaching Program Sample Methodology	0
2013-039	Revise One-Time Inspection Program Sample Methodology	0
2013-040	Revise Buried Cable Program to Dewater Based Upon Annunciation Rather Than Conditions	0
2013-042	Revise Commitment NLS2008071-25 to remove the “service water pipe slab”	0
2013-046	Revise Commitment NLS2009100-3 Committed Date from January 18, 2014, to January 18, 2017	0