UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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August 2, 2012

Mr. Larry Weber
Senior Vice President and
Chief Nuclear Officer
Indiana Michigan Power Company
Nuclear Generation Group
One Cook Place
Bridgman, MI 49106

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2 – NRC INTEGRATED INSPECTION REPORT 05000315/2012003 and 05000316/2012003

Dear Mr. Weber:

On June 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your D.C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on July 26, 2012, with Mr. J. Gebbie and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

One NRC identified and one self-revealed finding of very low safety significance (Green) were identified during this inspection.

One of these findings was determined to involve a violation of NRC requirements. Further, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating this violation as a Non-Cited Violation (NCV) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest this NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at D.C. Cook.

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III; and the NRC Resident Inspector at D.C. Cook.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," 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 NRC's Agencywide Document 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/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket Nos. 50-315; 50-316
License Nos. DPR-58; DPR-74

Enclosure: Inspection Report 05000315/2012003 and 05000316/2012003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000315; 05000316
License Nos:	DPR-58; DPR-74
Report No:	05000315/2012003; 05000316/2012003
Licensee:	Indiana Michigan Power Company
Facility:	D.C. Cook Nuclear Power Plant, Units 1 and 2
Location:	Bridgman, MI
Dates:	April 1 through June 30, 2012
Inspectors:	J. Lennartz, Senior Resident Inspector J. Ellegood, Senior Resident Inspector P. LaFlamme, Resident Inspector E. Sanchez Santiago, Reactor Inspector
Approved by:	John B. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000315/2012003, 05000316/2012003; 04/01/2012 – 06/30/2012; D.C. Cook Nuclear Power Plant, Units 1 & 2; Operability Determinations and Functional Assessments, Refueling and Other Outage Activities; Licensee Identified Violations

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings were identified by the inspectors. One finding was considered a Non-CitedVviolation (NCV) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after 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 and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. One self-revealed finding of very low safety significance was identified for the failure to implement the Unit 2 main generator volts per hertz differential relay modification per design, as required by Engineering Change (EC) 50316, "Unit 2 Replacement of the Volts/Hertz Relay and the Overall Differential Relays with a Multifunctional Relay Unit." Consequently, while ascending in power, the relay actuated causing a main generator trip, resultant turbine trip and subsequent reactor trip on April 30, 2012. For corrective actions, the licensee programmed the correct preset settings into the volts per hertz differential relay prior to restarting Unit 2 and plans to add additional procedural requirements to ensure modification requirements are properly incorporated into the associated work orders. This issue was entered into the licensee's corrective action program (CAP) as Action Request (AR) 2012-5744.

  The inspectors concluded the finding was more than minor because it is associated with the Initiating Events Cornerstone attribute of Procedure Quality. In addition, it adversely affected the Cornerstone objective to limit the likelihood of events that upset plant stability. Specifically, the failure to implement the SEL-487E relay modification per design, contributed to a main generator trip and resultant automatic reactor trip. The inspectors used IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone to determine the significance. This finding was of very low safety significance because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment will not be available. This finding is associated with a cross-cutting aspect in the resources component of the human performance cross-cutting area. Specifically, the work order associated with installing the volts per hertz overall differential relay did not include sufficient guidance to ensure the SEL-487E relay modification was installed as designed(H.2 (c)). (1R20)

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance and associated NCV for the failure to establish preventive maintenance schedules. Technical Specification (TS) 5.4.1 requires that written procedures be established, implemented and maintained for activities specified in Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, section 9, Procedures for Performing Maintenance, states, in part, that "Preventive Maintenance schedules should be developed to specify… inspection or replacement of parts that have a specific lifetime…." The licensee did not develop a maintenance schedule for replacing liquid crystal diodes (LCD) within a manufacturer specified five-year life. Consequently, 14 LCDs failed after about eight years of service and three failures resulted in unplanned Limiting Condition for Operation (LCO) entries. The licensee subsequently replaced the LCDs for safety-related displays and has entered the condition into the corrective action program as AR 2012-5744.

The inspectors concluded that the issue was more that minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control. In addition, it adversely affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events. Specifically, the failure to establish and implement scheduled replacement of the LCD displays resulted in three unplanned LCO entries for the affected recorders. The inspectors reviewed the finding in accordance with IMC 0609, Attachment 0609.04 Table 4a for the Mitigating Systems Cornerstone and concluded the finding was of very low safety significance because the answer to all four questions for mitigating structures, systems and components and functionality was 'no'. The inspectors concluded that the finding included a cross-cutting aspect in problem identification and resolution, Corrective Action Program, in that the licensee did not take appropriate corrective actions to address safety issues in a timely manner (P.1(d)). Specifically, the licensee did not replace safety-related LCD displays prior to failure until prompted by the Inspectors. (1R15)

B. Licensee-Identified Violations

One violation of very low safety significance was identified by the licensee, and has been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's CAP. This violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power the entire inspection period.

Unit 2 was in a shutdown condition and defueled to conduct Cycle 20 refueling outage activities when the inspection period started. On April 27, 2012, the reactor was taken critical and the main generator was synchronized to the grid on April 28, 2012, which ended Cycle 20 refueling outage. On April 30 during power ascension following the refueling outage, Unit 2 automatically tripped from 93 percent power because of a main generator/main turbine trip. After investigating the cause for the trip and implementing corrective actions, the licensee started the plant and synchronized the main generator to the grid on May 2, 2012. Unit 2 returned to full power on May 3, 2012 and was at full power when the inspection period ended.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the TSO and the plant during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the

continued operation of the safety-related loads without transferring to the onsite power supply;
- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- A re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- The communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their Corrective Action Program (CAP) in accordance with station corrective action procedures.

This inspection constituted one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Unit 1/2 east and west main steam enclosures;
- Unit 1/2 fire protection pump house; and
- Unit 2 transformers' 201 AB and CD deluge houses.

This inspection constituted one seasonal adverse weather sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2 west motor driven auxiliary feed water system;
- Unit 2 south safety injection system; and
- Unit 2 AB emergency diesel generator system.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone 58, Unit 2 control room cable vault;
- Fire Zones 1G & 1H; Unit 2 residual heat removal pump rooms;
- Fire Zone 107, Unit 2 auxiliary feed water pump;
- Fire Zone 81, Unit 1 turbine building south west 591 elevation
- Fire Zone 144, Unit 1 hot shutdown panel enclosure; and
- Fire Zone 42A, Unit 1 emergency power system transformer room.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event.
Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.
Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the corrective action program to verify the adequacy of the corrective actions. The inspectors walked down the following plant area to verify that the licensee complied with its commitments:

- Unit 2 steam generator blowdown flash tank room.

Specific documents reviewed during this inspection are listed in the Attachment to this report.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors observed and reviewed the licensee's testing of the Unit 2 west containment spray and CD emergency diesel generator jacket water heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents reviewed for this inspection are listed in the Attachment to this document.

This annual heat sink performance inspection constituted two samples as defined in IP 71111.07-05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

From March 26, 2012 through April 6, 2012, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system (RCS), steam generator (SG) tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

The reviews described in Sections 1R08.1, 1R08.2, R08.3, IR08.4, and 1R08.5 below, count as one inspection sample as described by IP 71111.08.

.1 Piping Systems Inservice Inspection

1. Inspection Scope

The inspectors observed and reviewed records of the following non-destructive examinations required by the American Society of Mechanical Engineers, (ASME) Section XI Code, and/or 10 CFR 50.55a to evaluate compliance with the ASME Code, Section XI, and Section V requirements, and if any indications and defects were detected, to determine if these were disposed in accordance with the ASME Code or an NRC approved alternative requirement:

- Ultrasonic examination (UT) of 91.5-inch diameter pressurizer vessel weld 2-PRZ-11;

- UT of 12-inch pressurizer vessel weld 1-PRZ-16;
- UT of 3, 10-inch diameter safety injection system welds 2-SI-56-14, 2-SI-56-15 and 2-SI-56-16; and
- Magnetic Particle examination of 32-inch diameter main steam line weld STM-24-MSN.

There were no Unit 2 examinations from the previous outage with relevant/recordable indications for review

The inspectors reviewed records of the following risk-significant pressure boundary ASME Code Section XI Class 1 and Class 2 welds fabricated since the beginning of the last refuelling outage to determine if the licensee: followed the welding procedure; applied appropriate weld filler material; and implemented the applicable Section XI or construction Code non-destructive examinations and acceptance criteria. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedure was qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

- Class 1 post accident sampling system valve 2-NRV-102 replacement due to leak by;
- Class 1 safety injection system valve 2-SI-156W replacement due to leak by; and
- Class 2 spent fuel system valve 2-SF-155 installment for leak rate testing.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the reactor vessel head, a bare metal visual examination was required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors observed a portion of the bare metal visual examination conducted on the reactor vessel head and reviewed the final inspection report to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). Specifically, to determine:

- If the required visual examination scope/coverage was achieved and limitations (if applicable were recorded), in accordance with the licensee procedures;
- If the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate; and
- For indications of potential through-wall leakage, that the licensee entered the condition into the corrective action system and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors independently walked down the Unit 2 RCS loop piping, including the reactor coolant pumps, pressurizer and emergency core cooling systems within containment to identify boric acid (BA) leakage. The inspectors then reviewed the walkdown performed by the licensee to ensure that components with boric acid deposits were identified and entered into the corrective action program. The inspectors observed these examinations to determine whether the licensee focused on locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of components with boric acid deposits to determine if the affected components were documented and properly evaluated in the corrective action system. Specifically, the inspectors evaluated the licensee's corrective actions to determine if degraded components met the component Construction Code and/or the ASME Section XI Code.

- AR 2011-2310-1; 2W-CCP Outboard Mechanical Seal Leak condition evaluation;
- AR 2010-6793-1; Leak above No. 4 accumulator, has worsened to 150 dpm condition evaluation;
- AR 2010-10354-2; Reactor Coolant Pump (RCP) had an active leak coming through the seal condition evaluation;
- AR 2010-11945-2; BA leak in Unit 2 containment from crane wall penetrations condition evaluation;
- AR 2010-12391-1; Body to bonnet BA leak on 2-RH-104E condition evaluation
- AR 2011-0206-1; 2W-RHR pump cover bolts with boric acid deposits on top condition evaluation; and
- AR 2011-13167-1; BA deposits 2-PP-9E condition evaluation.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- AR 2010-12391; Body to bonnet BA leak on 2-RH-104E;
- AR 2010-12833; Packing leak (inactive) on 2 RH-125E;
- AR 2011-1677; 2E-RHR pump mechanical seal leakage;
- AR 2011-10766; Unit 2 has a 0.6 gpm RCS leak; and
- AR 2011-13168; Various inactive BA leaks.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documentation related to the SG ISI program to determine if:

- The numbers and sizes of SG tube flaws/degradation identified were consistent with the licensee's previous outage Operational Assessment predictions;
- The SG tube ET examination scope and expansion criteria were sufficient to meet the Technical Specifications, and the Electric Power Research Institute TR-107569, Pressurized Water Reactor Steam Generator Examination Guidelines;
- The SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- The licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- The licensee implemented repair methods, which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- The licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- The licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;
- The ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current Examination, of Electric Power Research Institute TR-107569, Pressurized Water Reactor Steam Generator Examination Guidelines;
- The licensee performed secondary side SG inspections for location and removal of foreign materials;
- The licensee implemented repairs for SG tubes damaged by foreign material; and
- Foreign objects were left within the secondary side of the SGs, and if so, that the licensee implemented evaluations, which included the effects of foreign object migration and/or tube fretting damage.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's corrective action program and conducted interviews with licensee staff to determine if:

- The licensee had established an appropriate threshold for identifying ISI/SG related problems;
- The licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and

- The licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On June 12, 2012, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

On April 19, 2012, the inspectors observed activities in the control room during RCS vacuum fill. During this evolution, operators lowered reactor vessel water level below the 618.1 elevation level, which placed Unit 2 in reduced RCS inventory and orange risk; drew a vacuum; commenced filling the RCS; and exited reduced inventory. This was an

activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- Unit 1 power range nuclear instrumentation system; and
- Unit 1/2 plant air systems.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- planned Unit 1emergency service water dual pump outage on April 2;
- planned work on Unit 2 A train reserve feed breaker, 12-CD, during the week of April 8;
- planned evolution to reduce Unit 1 RCS to reduced inventory and vacuum fill the system on April 18 and 19;
- emergent maintenance on Unit 1 east control air dryer and planned maintenance on Unit 2 and the backup plant air compressors during the week of May 7; and
- planned maintenance on Unit 2 turbine driven auxiliary feedwater pump and Unit 1 AB emergency diesel generator on June 26-28.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

Specific documents reviewed during this inspection are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- shutdown boron concentration value evaluation;
- aggregate operability assessment following Unit 2 cycle 20 refueling outage;
- Unit 1 east essential service water backup air line in contact with scaffolding;
- regulatory guide 1.97 post accident monitoring recorders; and
- 2-WRV-728, Unit 2 emergency diesel generator south air after cooler essential service water temperature control valve repair.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

This operability inspection constituted five samples as defined in IP 71111.15-05.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and associated NCV of TS 5.4.1 for failing to have preventive maintenance schedules. Specifically, Regulatory Guide 1.33 requires licensee's to develop maintenance schedules for items that have a specific life span; however, the licensee did not develop a maintenance schedule for replacing liquid crystal diodes (LCDs) within a manufacturer specified five-year life.

Description: Between May of 2011 and April of 2012, the licensee experienced 14 failures of LCD screens on instrument recorders. Of these failures, three resulted in unplanned Limiting Condition for Operation (LCO) entries. Despite the failures, as of April 22, the licensee had not replaced the LCD displays of all safety-related recorders nor had the licensee considered the mission time of the recorders in determining past operability of the recorders. After reviewing AR 2012-4908 regarding failures of post accident monitoring Recorders, the inspectors inquired as to operability of the safety-related recorders because of the multiple LCO entries to replace failed recorders and the similar age of the rest of the safety-related recorders. Specifically, the inspectors were concerned with the capability of the installed recorders to meet their assumed mission time. In response, the licensee began a replacement campaign of the remaining recorders and assessed past-operability of the recorders. During the inspectors' review

of the vendor recommendations, the inspectors noted that the vendor recommended LCD replacement every 5 years. The recorders installed in the plant were about 8 years old. The licensee replaced the LCD module on safety-related recorders. Although the vendor provided recommendations for LCD replacement, the licensee neither implemented the vendor recommendations nor developed an alternate preventive maintenance scheduled.

In assessing current and past operability of the recorders, the licensee initially only considered the environmental qualifications of the instruments and did not consider the display to have a mission time since the display was located within the control room envelope. The inspectors reviewed Regulatory Guide 1.97 Rev. 3, Criteria for Accident Monitoring for Nuclear Power plants and concluded that Regulatory Guide 1.97 applies to "that part of the instrumentation system and its vital supporting features or power sources that provide direct display of the variables" as stated in Section B of the Regulatory Guide. While that portion of the instrument in the control room environment would not need an environmental qualification, the performance requirements, as stated in Section C.2.4, include determination of the time interval during which the measurement is needed. In the licensee's investigation, the licensee determined that the displays can be replaced post-accident; therefore, the mission time of the post-accident monitoring can be less than that for the associated detector. ANS-4.5, Criteria for Accident Monitoring Functions in Light Water-Cooled reactors, which is endorsed by Regulatory Guide 1.97 allows replacement of display channels if replacement can be accomplished post-accident in an acceptable out-of-service time. The inspectors concluded that replacement of the aged displays adequately addressed current operability and that, while installed, displays could be replaced within the 30 day LCO time.

Analysis: The inspectors determined the failure to develop preventive maintenance schedules for the post-accident monitoring was a performance deficiency that warranted a significance review. The inspectors reviewed the examples of minor issues in Inspection Manual Chapter (IMC) 0612 "Power Reactor Inspection reports, " Appendix E, "examples of Minor Issues," and determined that non applied. Consistent with IMC 0612, Appendix B, the inspectors concluded that the issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control. In addition, it adversely affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events. Specifically, the failure to establish and implement scheduled replacement of the LCD displays resulted in three unplanned LCO entries for the affected recorders. The inspectors reviewed the finding in accordance with IMC 0609, Attachment 0609.04 and concluded the finding was of very low safety significance because the answer to all four questions for mitigating structures, systems and components and functionality was 'no.' No components were inoperable for greater than the allowed time by TS.

The inspectors concluded that the finding included a cross-cutting aspect in problem identification and resolution, CAP, in that the licensee did not take appropriate corrective actions to address safety issues in a timely manner (P.1(d)). Specifically, the licensee did not replace safety-related LCD displays prior to failure until prompted by the Inspectors.

Enforcement: TS 5.4.1 requires that written procedures be established, implemented and maintained for activities specified in Regulatory Guide 1.33. Regulatory Guide 1.33,

Appendix A, Section 9, Procedures for Performing Maintenance, states, in part, that "Preventive Maintenance schedules should be developed to specify… inspection or replacement of parts that have a specific lifetime…." The vendor for the instrument recommended a five-year replacement interval for the LCD. Contrary to this requirement, as of April 22, 2012, the licensee had neither developed a replacement schedule nor an inspection schedule for the LCD display for the post-accident monitoring instruments. Consequently, between May 2011 and April 22, 2012, 14 control room recorders failed, including three that required an LCO entry. The licensee has subsequently replaced the displays for Unit 1 and 2 safety-related recorders. Because this violation was of very low safety significance and was entered into the licensee's CAP as AR 2012-5330, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy, (NCV 05000315/2012003-01) Failure to Replace Post-Accident Monitor Displays.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following modification:

- Unit 2 AB and CD emergency diesel generator jacket water pumps time delay.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 refueling water storage tank to centrifugal charging pumps suction head shutoff valve leak test (2-IMO- 910 and 911) following maintenance;
- Unit 2 CD emergency diesel generator 18-month maintenance overhaul;
- Unit 2 west centrifugal charging pump seal replacement;
- Unit 2 AB emergency diesel generator 18-month maintenance overhaul; and
- supplemental diesel generators following correction fuel line air leak

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted five post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 refueling outage (RFO), conducted March 21 to April 28, 2012, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out of service.

- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by TS.
- Licensee fatigue management, as required by 10 CFR 26, Subpart I.
- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to RFO activities.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

No findings were identified.

.2 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled outage that began on April 30, 2012, when Unit 2 reactor automatically tripped, as designed, in response to a turbine trip. After investigating the cause for the turbine trip and implementing corrective actions, Unit 2 reactor was started up and the main generator was synchronized to the grid on May 2, 2012, which ended the outage.

The inspectors reviewed activities to ensure that the licensee considered risk while implementing the outage and the post-trip report, and observed startup activities. The inspectors also verified problems associated with the outage were entered in the CAP with the appropriate characterization and that appropriate corrective actions were completed. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

b. Findings

Introduction: A self-revealing finding of very low safety significance (Green) occurred because the licensee failed to implement the Unit 2 main generator volts per hertz differential relay modification per design, as required by EC 50316, “Unit 2 Replacement

of the Volts/Hertz Relay and the Overall Differential Relays with a Multifunctional Relay Unit." Consequently, while ascending in power, the relay actuated causing a main generator trip, followed by a turbine trip and subsequent reactor trip.

Description: On April 30, 2012, while at 92 percent power and ascending to 100 percent power, the Unit 2 generator volts per hertz differential relay actuated causing a turbine trip and subsequent reactor trip. An investigation by licensee personnel concluded that the relay actuation did not result from an actual electrical fault but instead resulted from a failure to install the relay per design. The licensee replaced the volts per hertz differential relay, SEL-478E, during the Unit 2 cycle 20 refueling outage per WO 5593485, "Replace Volts per Hertz Relay during U2C20." An Engineering Change, EC 50316, governed the replacement and required installation of a module with preset programmed settings. An AEP technician unaffiliated with the plant programmed and tested the module as required by the modification package prior to installation. However, the contractor set the current ratio settings within the relay modification to an incorrect value during module programming. This error resulted in a volts per hertz actuation signal. EC 50316 included a requirement for the site to validate the preset settings prior to starting up Unit 2. However, the WO associated with installing the relay module did not include this requirement. Consequently, the wrong preset current ratio settings remained programmed in the SEL-487E relay module.

Analysis: The inspectors determined that failure to implement the Unit 2 generator volts per hertz differential relay modification per design was a performance deficiency that warranted an evaluation in accordance with the SDP. The inspectors reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that this issue was more than minor because it was associated with the Initiating Events cornerstone attribute of design control and that adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the failure to implement the SEL-487E relay modification per design, contributed to a main generator trip and resultant automatic reactor trip. The inspectors performed a Phase 1 SDP review using the guidance provided in IMC 0609, Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," and determined that this finding was of very low safety significance because the finding does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment will not be available.

The inspectors concluded that this finding was associated with a cross-cutting aspect in the resources component of the human performance cross-cutting area. Specifically, the WO associated with installing the volts per hertz overall differential relay did not include sufficient guidance to ensure the SEL-487E relay modification was installed as designed. (H.2 (c)).

Enforcement: Enforcement action does not apply because the performance deficiency was associated with work on non-safety related equipment and did not involve a violation of a regulatory requirement. The licensee entered the issue into the licensee's CAP (AR 2012-5744). For corrective actions, the licensee programmed the correct preset settings into the volts per hertz differential relay prior to restarting Unit 2 and

plans to add additional procedural requirements to ensure modification requirements are properly incorporated into the associated work orders.

Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as a finding (FIN 05000316/2012003-02, Failure to Implement Volts per Hertz Differential Relay Modification per Design.)

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 2 as-left ice condenser intermediate deck door surveillance test (containment isolation valve);
- Unit 2 local leak rate surveillance (containment isolation valve);
- Unit 2 safety injection system check valve test (inservice test);
- Unit 2 AB emergency diesel generator surveillance test (routine); and
- Unit 1 reactor coolant system leak rate test (reactor coolant system leakage detection).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;

- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted one routine surveillance testing sample, one inservice testing sample, one reactor coolant system leak detection inspection sample, and two containment isolation valve samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on June 12, 2012, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator (PI) data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also reviewed the post-evolution critique for the scenario. The inspectors noted any weaknesses and deficiencies in the crew's performance and ensured that the licensee evaluators noted the same issues and entered them into the CAP. The inspectors also reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings were identified.

2. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Emergency Alternating Current Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports and NRC Integrated IRs for the period of April 2011 through March 2012 to validate the submittals accuracy. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - High Pressure Injection Systems PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC Integrated IRs for the period of April 2011 through March 2012 to validate the submittals accuracy. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index – Auxiliary Feedwater System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI – Auxiliary Feedwater System PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period of April 2011 through March 2012 to validate the submittals accuracy. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC Integrated IRs for the period of April 2011 through March 2012 to validate the submittals accuracy. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of April 2011 through March 2012 to validate the submittals accuracy. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and

adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for followup, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6 month period of October 2011 through March 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or reworks maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted a single semiannual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 Unit 2 Automatic Reactor Trip

a. Inspection Scope

The inspectors observed the control room operators respond to a Unit 2 automatic reactor trip on April 30, 2012, that was caused by a turbine trip. The inspectors verified that control room operators responded in accordance with plant procedures; walked down control panels to verify that plant equipment responded as designed; and verified that the event was accurately described and that the NRC was notified in a timely manner. The inspectors also reviewed action requests to verify that identified problems pertaining to the trip were entered into the CAP with the appropriate significance characterization. Documents reviewed in this inspection are listed in the Attachment.

This event followup review constituted one sample as defined in IP 71153-05. One Finding was indentified and was documented in section 1R20.

b. Findings

No additional findings were identified.

.2 (Closed) Licensee Event Report 05000315/2012-001-00

a. Inspection Scope

The inspectors reviewed the events and circumstances surrounding the February 17, 2012, Unit 1 entry into TS LCO 3.0.3 which resulted when control room operators discovered that two power range nuclear instrumentation channels were inoperable at the same time. The inspectors reviewed control room logs, interviewed control room operators and maintenance workers and reviewed the in-depth apparent cause that was documented in AR 2012-2189, Unit 1 Power Range Drawer Calibration Came into Question, to verify that the event was accurately reported.

On February 17, 2012, while performing calibrations on the power range nuclear instruments, 2 of 4 channels were adjusted out of tolerance below the TS allowable limit requiring operators to prepare to commence a plant shutdown within 1 hour if an additional nuclear instrument channel was not returned to operable status. However, an additional power range nuclear instrument was returned to operable status, which satisfied the required actions and TS LCO 3.0.3 was exited before commencing a shutdown. The licensee's in-depth apparent cause evaluation determined the out of tolerance adjustments were a result of a failed recorder used during the calibration procedure. The inspectors noted that two additional recorders were used to re-calibrate both channels to within operable limits in accordance with TS 3.3.1.

The inspectors observed maintenance workers re-calibrate the power range nuclear instruments with the new recorders and verified compliance with TS 3.3.1 prior to exiting TS LCO 3.0.3. No additional safety concerns were identified. No performance deficiency was identified. This Licensee Event Report (LER) is closed.

This event followup review constituted one sample as defined in IP 71153-05.

b. Findings

No findings were identified.

.3 (Closed) Licensee Event Report 05000315/2011-002-00

a. Inspection Scope

The inspectors reviewed the events and circumstances surrounding the November 25, 2011 event in which rising vibrations on the Unit 1 east Main Feed Pump led to a trip of the pump. During the evening of November 24, plant operators noted rising vibrations on the Unit 1 east Main Feed Pump. The operators increased vibration monitoring of the feed pump and briefed actions to take if the pump tripped. In the morning of November 25, 2011, vibrations rose sufficiently that the operators needed to secure the pump. At 0517, operators entered the Rapid Power Reduction Procedure and at 0522 tripped the Unit 1 east main feed pump. Operators manually started both motor driven auxiliary feed pumps and the turbine driven auxiliary feed pump and stabilized the plant at 58 percent power. The licensee reported the event in accordance with 10 CFR 50.73(a)(2)(iv)(A) because the licensee started auxiliary feedwater pumps in response to a plant transient.

Subsequent evaluation of the pump revealed a cracked shaft. The licensee performed a root cause of the shaft failure and determined that one end of the shaft coupling lacked grease. The licensee concluded that during assembly of the pump in a recent refueling outage, the work instruction did not include adequate guidance to install an undersized o-ring. The lack of adequate instruction led to improper o-ring installation and subsequent loss of lubrication in the coupling. Without lubrication, the feed pump shaft suffered from high stresses due to fretting and increased friction. Although the failure to properly perform maintenance on the feed pump represented a failure to meet to meet internal standards set forth in PMP-2291-PLN-001, Work Control Activity Planning Process for adequacy of the work instruction, the feed pump is not safety-related; thus the issue did not represent a violation of NRC requirements. The inspectors determined the issue was a licensee–identified performance deficiency since the site took proactive action to monitor and remove the pump from service prior to a transient. However, in order to understand the significance of the issue, the inspectors assessed the safety consequences via the significance determination process. The inspectors concluded that the event impacted the initiating event cornerstone objective of limiting the likelihood of events that upset plant stability and the Mitigating System Cornerstone objective of ensuring the reliability of systems that respond to events. The inspectors reviewed IMC 0609.04, “Phase 1 Initial Screening and Characterization of Findings” and determined that the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The failure of a main feedwater pump could result in a transient and a loss of function for the failed pump. The inspectors and Senior Reactor Analysts (SRAs) reviewed the pre-solved Risk-Informed Inspection

notebook for D.C. Cook and determined that the notebook only captured the mitigating system function of the main feedwater pump and did not estimate the impact on the initiating events cornerstone.

The Region III SRAs used the risk-informed notebook to perform an SDP phase 2 evaluation assuming an exposure period for the performance deficiency of 1 year. The SRAs performed a bounding analysis and assumed that the performance deficiency increased the likelihood of a transient with the loss of the power conversion system, even though during the actual pump failure event, operators reduced power and removed the pump from service, avoiding a transient. To model this potential impact, the SRAs increased the frequency of the power conversion system by one order of magnitude in accordance with the IMC 0609 Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations". The result was a finding of very low safety significance. The dominant sequence was a transient with failure of auxiliary feedwater, power conversion system, and feed and bleed functions. Since the internal events SDP result included a sequence of "7", the SRAs reviewed the potential impact of external event and large early release frequency risk contributions.

External event and large early release frequency contributions were determined to be negligible using the guidance of IMC 0609 Appendix A, Attachment 3, "User Guide for Screening of External Event Contributions" and IMC 0609 Appendix H, "Containment Integrity Significance Determination Process". The main feedwater system is not used for safe shutdown in fire or seismic events. Internal flooding risk contributions were screened using Table 3.1, "Plant Specific Flood Scenarios" since no significant flood scenarios were listed for D.C. Cook. Large early release frequency contributions screened because the dominant sequence did not involve an inter-system loss-of-coolant accident, steam generator tube rupture, or a station blackout event. Therefore, the event was of very low safety significance. The licensee identified the degrading condition through monitoring of pump vibrations on a display in the control room and took action to secure the pump prior to more significant plant damage. Since the event did not included a violation of NRC requirements and did not represent a greater than green condition, the inspectors concluded no enforcement action was warranted, per the Enforcement Policy. The licensee replaced the failed components and revised the procedure for main feed pump maintenance. No additional safety concerns were identified. This LER is closed.

This event followup review constituted one sample as defined in IP 71153-05.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 Exit Meeting Summary

- On July 26, 2012, the inspectors presented the inspection results to Mr. J. Gebbie, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that the potential report input discussed was not considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The in-service inspection results with Mr. J. Gebbie and other members of the licensee staff on April 6, 2012.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

Cornerstone: Initiating Events

In June of 2011 during a review of inquiries and replies in the ISI Program Owners Group electronic forum, the licensee was prompted to review whether the Reactor Vessel Supports were included in the ISI program. A review of Cook Nuclear Plant ISI Program Plans from initial plant operation to the current date for both units revealed that the reactor vessel supports had not been included in the ISI Program Plans; therefore ASME code examinations of these supports were not scheduled or performed during the previous ISI intervals. Title 10 CFR 50.55a g(4) states: throughout the service life of a pressurizer water cooled nuclear power facility, components (including supports) which are classified ASME Code Class 1, Class 2 and Class 3 must meet the requirements set forth in ASME Section XI. ASME Section XI IWF-2510 states in part that supports shall be examined in accordance with Table IWF-2500-1, which requires 100 percent of supports other than piping supports be inspected using the VT-3 examination requirements, each inspection interval. The reactor vessel supports are Class 1, non-piping supports; and therefore required to be 100 percent inspected during each ISI interval. Contrary to the above, as of June 2011 the reactor vessel supports, Class I supports, had not been inspected in accordance with the CFR. Though the licensee was performing visual examinations during every outage, these examinations were not driven by a procedure, nor did they have associated lighting requirements or acceptance criteria as would be required by the ASME code.

The licensee has accessed the sand box areas, which contain the reactor vessel supports, various times to perform inspections and other maintenance activities and no degradation was noted during any of these activities. Based on this, the licensee determined there is no reason to think there is non-negligible degradation or damage to these supports and they remain operable. Based on the assessment the supports are operable, this finding is of very low safety significance. This issue was documented in AR 2011-8149 and the licensee is currently scheduled to perform the reactor vessel support inspections during the next refueling outage for each unit.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
L. Weber, Senior Vice President and Chief Nuclear Officer
M. Carlson, Site Support Services Vice President
J. Chambers, Emergency Preparedness Manager
H. Etheridge, Licensing Manager
J. Gebbie, Site Vice President
R. Hall, ISI Program Owner
B. Hite, Radiation Protection Manager
C. Hutchinson, Nuclear Site Services Director
Q. Lies, Plant Manager
J. Nimtz, Regulatory Affairs Senior Licensing Activities Coordinator
S. Mitchell, Regulatory Affairs
K. O'Conner, Compliance Manager
R. Pickard, Engineering Manager
J. Ross, Engineering Director
M. Scarpello, Regulatory Affairs Manager
R. Sieber, Training Manager
B. Evans, Operations Training Manager
T. Johanson, Operations Requalification Training
T. Vriezema, Simulator Supervisor

Nuclear Regulatory Commission
John B. Giessner, Chief, Reactor Projects Branch 4
John Jandovitz, Project Engineer, Branch 5
Laura Kozak, Senior Risk Analyst

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000315/2012003-01	NCV	Failure to Replace Post-Accident Monitor Displays (1R15)
05000316/2012003-02	FIN	Failure to Implement Volts per Hertz Differential Relay Modification per Design (1R20.2)

Closed

05000315/2012003-01	NCV	Failure to Replace Post-Accident Monitor Displays (1R15)
05000316/2012003-02	FIN	Failure to Implement Volts per Hertz Differential Relay Modification per Design (1R20.2)
05000315/2012-001-00	LER	Two Power Range Nuclear Instruments Inoperable Due to Common Cause (4OA3.2)
05000315/2011-002-00	LER	Manual Actuation of Auxiliary Feedwater Systems in Response to Loss of One Main Feedwater Pump (4OA3.3)

Discussed

NONE

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather Protection

- 12-IHP-5040-EMP-004, Plant Winterization and De-winterization, May 15, 2012
- AR 2011-11477, Circuit Bkr K and K1 Not Positioning IAW Clearance Order
- AR 2011-12135, 12-IHP-4030-044-001 Needs FWTD Phones Numbers Changed
- AR 2011-14342, 201AB Transformer Deluge Hose Heater Not Working
- AR 2011-5295, 12-hv-fph-uhe-2 Fan Conductor Chattering
- Clearance N-VAB-SDAL-2839 (004), Unit 1 East Steam Enclosure Exhaust Fan Clearance, May 30, 2012
- PMP-3100-IOA-001, Inter-Organizational Agreement Between the AEP Utility Operations and the AEP Nuclear Generation Group For Assistance to Cook Nuclear Plant, Revision 6
- PMP-5020-001-001, Maintenance Permits, Revision 30
- PMP-5055-001-001, Winterization/Summerization, May 18, 2012
- Seasonal Readiness Affirmation Letter, May 18, 2012
- WO 55376188-06, 12-HV-HTAH-1, PMT After Fan Repairs, December 12, 2011

1R04 Equipment Alignment

- 1-EHP-4030-116-248, CCW Flow Balance, Revision 7
- 1-Figure 19.8, Technical Data Book Safety-related Throttle Valves , Revision 28
- 2-Figure 19.8, Technical Data Book Safety-related Throttled Valves, Revision 39
- 2-OHP-4021-008-001, Filling and Venting the Safety Injection System, Residual Heat Removal System and Boron Injection Tank, Revision 32
- 2-OHP-4021-008-002, Placing Emergency Core Cooling System in Standby Readiness, Revision 24
- 2-OHP-4021-054-001, Operation of Condensate System, Revision 25
- 2-OHP-4021-056-001, Filling and Venting Auxiliary Feedwater System, Revision 25
- AR 2010-6298, Test Connection Fitting Degraded Threads
- AR 2012-5007, Unit 2 North SI Pump has Oil Leak at Fill Connection
- AR 2012-5418, SI Pressurization
- AR 2012-5880, Unit 1 TDB and Unit 2 TDB fig 19.8 Do Not Agree
- AR 2012-6103, West MDAFP Lineup
- AR 2012-6104, 2-PP-3W leaking oil
- AR 2012-6179, 2-RH-113W Has Dried Boric Acid on Packing Follower
- AR 2012-7207, Unit 2 TDAFW Pump Turbine Governor Oil Level Hi
- OP-1-5135C, CCW Misc. Services Auxiliary Building, Revision 7
- OP-2-5104C, Composite Flow Diagram Engineered Safety Systems, Revision 9
- OP-2-5106A, Aux Feedwater Flow Diagram, Revision 55
- OP-2-5142, Flow Diagram Emergency Core Cooling, Revision 51

1R05 Fire Protection

- AR 2012-4091, 1-DR-Aux491 Seal Condition is Degraded
- AR 2012-6358, Fire Seal F6982 Found Inoperable
- Fire Hazards Analysis, Revision 15
- Fire Pre-Plan, Fire Area AA 41, E.P.S. Control Rod Drive Room Unit 1, Revision 9

1R06 Flood Protection

- 12-EHP-5040-MOD-019, Limited Design Change Package, 2-LDCP-4447, Support Modifications so CVC Letdown and Blowdown Piping, Unit 2, Revision 0
- Flooding Evaluation for AEP D. C. Cook Unit 2, SL-5369, Revision 0
- PMP-1040-SES-001, Safety Screening, 2-LDCP-4447, Attachment 2, Revision 0

1R07 Heat Sink Performance

- 12-EHP-8913-001-002, U2 CD EDG Jacket Water Cooler Heat Exchanger Inspection, April 7, 2012
- 12-EHP-8913-001-002, U2 West CTS Heat Exchanger Inspection, March 28, 2012
- AR 2012-4581, 2-QT-131-CD GL 89-13 Inspection and Degraded Channel Cover
- AR 2012-4583, 2-QT-110-CD GL 89-13 Inspection and Degraded Channel Cover
- WO 55226749-04, 2-QT-131-CD Inspections and Cleaning, April 8, 2012

1R08 Inservice Inspection Activities

- 12-QHP-5050-NDE-027 Data Sheet 1, Visual Examination Report, March 27, 2012
- 12-QHP-5050-NDE-027, Visual Examination for Boric Acid and Condition of Component Surfaces, Revision 3
- 2-OHP-4030-001-002, Containment Inspection Tours, Revision 25
- AR 2010-10354, RCP had an Active Leak Coming through the Seal
- AR 2010-10355, Dry Boric Acid was Identified on the Spray Header Nozzle
- AR 2010-11552, 2-CS-535 is Leaking
- AR 2010-11945, BA Leak in U2 Containment Basement from Crane Wall Penetrations
- AR 2010-12391, Body to Bonnet Boric Acid Leak on 2-RH-104E
- AR 2010-12833, Packing Leak (inactive) on 2-RH-125E
- AR 2010-6793, Leak above #4 accumulator, has Worsened to 150 dpm
- AR 2011-0206, 2W-RHR Pump Cover Bolts with Boric Acid Deposits on Top
- AR 2011-10669, Electronic Dosimetry Lost in U2 Upper Ice Condenser
- AR 2011-10766, Unit 2 has a 0.6 gpm RCS Leak
- AR 2011-12437, Possible through Wall Leak Near 1-NFP-222-V2
- AR 2011-12832, Code Required Exams Were not Performed
- AR 2011-13167, Boric Acid Deposits 2-PP-9E
- AR 2011-13168, Various Inactive Boric Acid Leaks
- AR 2011-1677, 2E-RHR Pump Mechanical Seal Leakage
- AR 2011-2310, 2W-CCP Outboard Mechanical Seal Leak
- AR 2011-4206, 2W-CCP Outboard Mechanical Seal Leakage
- AR 2011-8149, Reactor Vessel Supports not Included in ISI Program Scope
- AR 2012-0571, Missing ASME Section XI Work Orders
- AR 2012-3538, Boric Acid Leaks-U2C20 Containment Leak Inspection
- AREVA 03-9176359, DC Cook Unit-2 Eddy Current Analysis Guidelines, March 30, 2012

- Calibration No. U2R97-238, Framatome Technologies UT Calibration Sheet 2-PRZ-11, November 14, 1997
- Figure A-4, D.C Cook Unit 2 Pressurizer
- GT 2012-4037, Reactor Vessel Closure Head Examination Results, March 29, 2012
- MHI-5075, ASME Section XI Repair/Replacement Program, Revision 11
- MT-7, Magnetic Particle Examination Continuous Dry powder Yoke Method, Revision 4
- PDI-UT-2, Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds, Revision E
- PMI-5070, Inservice Inspection, Revision 21
- PMP-5030-001-001, Boric Acid Corrosion of Ferritic Steel Components and Materials, Revision 15
- PMP-5070-ISI-002, Inservice Inspection Program Implementation, Revision 11
- PQR 136, Procedure Qualification Record, Revision 1
- PQR 219, Procedure Qualification Record, Revision 1
- PQR 234, Procedure Qualification Record, Revision 3
- PQR 235, Procedure Qualification Record, Revision 2
- PQR 256, Procedure Qualification Record, Revision 1
- PQR 258, Procedure Qualification Record, Revision 1
- PQR 454-C, Procedure Qualification Record, Revision 0
- PQR 455-C, Procedure Qualification Record, Revision 0
- Project Number 03-0309, Sheet 006100, ISwT Examination Summary Record, May 28, 2003
- U2-VE-12-001, Magnetic Particle Examination of STM-24-MSN, April 4, 2012
- U2-VE-12-002, Ultrasonic Examination of 2-PRZ-16, April 2, 2012
- U2-VE-12-003, Ultrasonic Examination of 2-PRZ-16, April 2, 2012
- U2-VE-12-014, Ultrasonic Examination of 2-SI-56-14, April 4, 2012
- U2-VE-12-028, Ultrasonic Examination of 2-SI-56-15, April 4, 2012
- U2-VE-12-029, Ultrasonic Examination of 2-SI-56-16, April 4, 2012
- UT-110, Ultrasonic Examination of Vessel Welds and Adjacent Base Metal >2.0” in Thickness, Revision 0
- UT-95, Ultrasonic Examination of Austenitic Piping Welds, Revision 6
- WO 55326338-02, 2-SI-156W, Replace Valve, March 12, 2010
- WO 55343496-11, 2-SF-155: Install Valve per EC-49975, October 6, 2010
- WO 55349411-01, 2-NRV-102, Install New Valve/Actuator, June 11, 2011
- WO 55349411-02, 2-NRV-102, Pre-Fabricate a Replacement Valve, July 14, 2011
- WPS 1.2 TS, Welding Procedure Specification, Revision 4
- WPS 8.0 TS, Welding Procedure Specification; Revision 3

1R11 Licensed Operator Requalification Program

- AR 2012-2189, U1 Power Range Drawer Cal Came Into Question
- AR 2010-8983, Operator Response Time for Mode 4 LOCA Exceeded Time Limit
- RQ-E-3702-U2-A, Cycle 3702 As-Found Simulator Evaluation, Revision 0

1R12 Maintenance Effectiveness

- 1-IHP-4030-113-131Q, Nuclear Instrumentation Power Range Channel Operational Test and Calibration With New Flux Data Equivalent Voltages, February 17, 2012
- 2 Year Unavailability Report for Compressed Air System Unit 1&2, 2010-2011
- AR 2010-8350, As Found Power Range Bistables Out of Tolerance
- AR 2011-5898, Failed PMT for Reactor Movable Incore Instrumentation Flux Wire
- AR 2012-3357, Unit 1 PAC Tripped Within Minutes After a Start

- AR 2012-7502, Unavailability Tracking of Plant Air Compressors Not Current
- Compressed Air System Maintenance Rule Scoping Document, March 27, 2001
- Nuclear Instrumentation System Maintenance Rule Scoping Document, November 16, 2011
- Unit 1/2 Nuclear Instrumentation System Health Reports 2011/2012
- WO 55362105-01, PAC Trouble Alarm In, April 23, 2010
- WO 55365685-04, Power Range Channel IV Calibration, February 17, 2012
- WO 55365686-04, Power Range Channel III Calibration, February 17, 2012
- WO 55365687-04, Power Range Channel II Calibration, February 17, 2012
- WO 55365688-04, Power Range Channel I Calibration, February 17, 2012
- WO 55366925-01, 2-OME-41, Repair Air Leak 1st Stage Inlet Piping, October 1, 2011
- WO 55383033-01, 2-OME-41, Repair Oil Leak on Unit 2 PAC, August 6, 2011
- WO 55383058-01, U2 PAC Surging, Invest, and Troubleshoot, February 18, 2012

1R13 Maintenance Risk Assessments and Emergent Work Control

- 2-OHP-4030-214-031, Operations Weekly Surveillance Checks, Revision 21
- 2-OHP-5030-001-002, Outage Risk and Technical Specification Monitoring, Revision 15
- AR 2012-8011, Safety Monitor Model Error
- Control Room Logs, April 2, April 8-13, April 18-19, May 7-11, June 26-28
- Daily work activity schedule, April 2, April 8-13, April 18-19, May 7-11, June 26-28
- PMP-2291-OLR-001, Online Risk Management, Part 1, Configuration Risk Assessment, April 2, April 8-13, April 18-19, May 7-11, June 26-28
- PMP-4100-SDR-001, Plant Shutdown Safety and Risk Management, Revision 25

1R15 Operability Determinations and Functionality Assessments

- 1-Figure 1.3b, Tech Data Book Excess Shutdown Margin and Single Stuck Out Rod Worth, October 21, 2011
- 1-Figure 4.5, Tech Data Book Minimum Required Boron Concentration, April 4, 2012
- 2-OHP-4030-232-027AB, AB Diesel Generator Operability Test, March 23, 2011
- 2-OHP-4030-232-027AB, AB Diesel Generator Operability Test, May 20, 2012
- AR 2012-1431, Westinghouse Calc Error Impacting Shutdown Boron Values
- AR 2012-4648, Aggregate ODE Review for U2CY20
- AR 2012-4908, Work Request for Immediate Recorder replacement
- AR 2012-5330, Mission time Operability Impact on Reg. Guide 1.97 Recorders
- AR 2012-7452, 2-WRV-728 would not stroke
- DIT-S-00705-15, Unit 1 and 2 Burnup Data, March 21, 2012

1R18 Plant Modifications

- AR 2012-4341, EC0000050057 Did Not Have a Post Install test Procedure
- EC0000050057, U2 EDG Load Margin Recovery, Revision 0

1R19 Post-Maintenance Testing

- 2-EHP-4030-218-001, RWST Isolation Valve Leak Test, April 11, 2012
- 2-OHP-4021-032-001AB,DG2AB Operation, April 5, 2012
- 2-OHP-4021-032-001CD, DG2CD Operation, April 14, 2012
- 2-OHP-4030-203-052W, West Centrifugal Charging Pump Operability Test, April 16, 2012
- 2-OHP-4030-232-027CD, CD Diesel Generator Operability Test, April 15, 2012
- AR 2011-10624, Diesel Crankcase Vacuum Reading

- AR 2012-4404, Failed PMT on 2-QT-501-AB
- AR 2012-4428, During Initial Testing of 2AB we Experienced a Lube Oil Trip
- AR 2012-4444, AB EDG Flow Diverted with Diesel Running
- AR 2012-4526, 2-PP-50W has Unusually High Rotor Assembly Rotational Drag
- AR 2012-4550, 2CD 1R JW Outlet Lower Gooseneck has 200 DPM Leak
- AR 2012-4818, Unable to Achieve Required Coupling Gap on 2-PP-50W
- AR 2012-4952, U2 West CCP Differential Pressure Low
- AR 2012-6248, Supplemental Diesel generator 2 Automatic Shutdown Following Start
- AR 2012-7449, 2-SV-16-AB Failed as Found Lift Test on First Test
- IPTE Briefing Guide, Freeze Seal for Unit 2 IMO 910/911 on 24" RWST Line, April 4, 2012
- WO 55374200-02, 2-PP-50W CCP PMT, April 14, 2012
- WO 55374530-02, Refurbish or Replace Regulator 2-XRV-232, April 5, 2012
- WO 55383058-08, 2-OME-41, Perform a Visual PMT Inspection, February 18, 2012

1R20 Refueling and Other Outage Activities

- 12-EHP-4030-002-356, Low Power Physics Tests with Dynamic Rod worth Measurement, Revision 10
- 12-MHP-5021-002-017, Reactor Vent Hose Installation and Removal, March 21, 2012
- 12-MHP-5021-002-017, Reactor Vent Hose Installation and Removal, April 20, 2012
- 12-OHP-4022-018-001, Loss of Spent Fuel Pit Cooling, Revision 18
- 12-OHP-4050-FHP-023, Reactor Vessel Head Removal With Fuel in the Vessel, March 26, 2012
- 2-OHP-4012-001-002, Reactor Startup, Revision 046
- 2-OHP-4021-001-001, Plant Heatup From Cold Shutdown to Hot Standby, Revision 65
- 2-OHP-4021-001-003, Power Reduction, Revision 43
- 2-OHP-4021-001-004, Plant Cooldown From Hot Standby to Cold Shutdown, Revision 54
- 2-OHP-4021-002-005, RCS Draining, March 28, 2012
- 2-OHP-4021-002-013, Reactor Coolant System Vacuum Fill, May 5, 2012
- 2-OHP-4021-013-005, Visual Audio Count Rate Channel, Revision 010
- 2-OHP-4030-001-002, Containment Inspection Tours, Revision 25
- 2-OHP-4030-227-037, Refueling Surveillance, Revision 18
- 2-OHP-4030-227-041, Refueling Integrity, Revision 20
- AR 2012-3635, Missile Block Seal Plate Dropped
- AR 2012-3651, 1VMO-101 Actuator has no T-Drain in Limit Switch Compartment
- AR 2012-3796, Leakage During Testing of 2-IMO-910,911 and 2-SI-185
- AR 2012-3805, Unit 2 Seal Table Drain Line is Missing
- AR 2012-4193, Steam Generator 3 Narrow Range 2-BLP-131 Indicating High
- AR 2012-4217, 2-IMO-330 Manually Operated
- AR 2012-4290, 2-IMO-316 Overthrusted in Close Direction
- AR 2012-4480, Damage to Base Metal on 2-FRV-240 During FAC Prep
- AR 2012-4522, 2-ECR-20-ACT Actuator is Defective
- AR 2012-4526, 2-PP-50W Has Unusually High Rotor Assembly Rotational Drag
- AR 2012-4595, Broke Switch Terminal on 2-PS-403
- AR 2012-4653, 2-RH-154W Missing a Body to Bonnet Nut and Bolt
- AR 2012-4829, Damage on the 2-HV=AFP-T2AC TDAFP Room Cooler
- AR 2012-4856, 2-NLP-151 Indicates Low
- AR 2012-4858, 2-CCM-430 Will Not Operate From Control Switch
- AR 2012-5087, 2-DCR-303 Control Air Leak
- AR 2012-5100, Source Range Detector N-31 Indication is Failed Low
- AR 2012-5317, 2-MFC-111, Steam Generator 1 Steam Flow Transmitter Reading High

- AR 2012-5399, RCP #24, Boric Acid Residue Near Main Flange
- AR 2012-5418, Uncontrolled SI Pump Discharge Header Pressure
- AR 2012-5782, Cover Plate Installed Incorrectly on Rx Head Vent Hose Slot
- AR 2112-3674, U2C20 Recirc Sump Walkdown #1
- DIT-S-06228-00, Unit 2 End of Cycle 19 Time-to-Boil Information, Revision 0
- DIT-S-06230-00, Unit 2 Beginning of Cycle 20 Time-to-Boil Information, Revision 0
- IPTE Briefing Guide, RCS Vacuum Fill, March 12, 2012
- ITPE Briefing Guide, RCS Drain, 20% PZR to FLNG for Head Removal with Fuel in the Vessel, Revision 0
- OHI-6100, Attachment 4, Unit 2 RCS Cooldown Rate Limit Curve, March 21-22, 2012
- R-MS-STM-0031, Main Steam Master Clearance, April 23, 2012
- WO 55376502-05, Install/remove vent hose at 2-RC-137, April 20, 2012
- WO 55399739-05, 2-PS-403 PMT, April 11, 2012
- WO-55226721-03, 2-IMO-330 PMT Stoke, April 12, 2012
- WO-55373483-14, 2CCM-430, Stroke for PMT/Operability, April 17, 2012
- WO-55401549-01, RX Cavity Ladder #1, April 19, 2012
- WO-55402252-02, 2-DCR-303 Will Not Operate, April 21, 2012
- WO-55402252-04, Ops, 2-DCR-303, Stroke Valve for IST and P.M.T., April 23, 2012

1R22 Surveillance Testing

- 12-MHP-4030-010-004, Ice Condenser Intermediate Deck Door Surveillance, April 19, 2012
- 1-OHP-4030-102-016, Reactor Coolant System Leak Test, June 26, 2012
- 2-EHP-4030-234-203, Unit 2 Local Leak Rate Testing, March 28, 2012
- 2-OHP-4030-208-008R, ECCS Check Valve Test, Revision 18
- AR 2012-3155, Unit 2 RCS Leak Rate Entered into Tier 1
- AR 2012-3900, A/F Leak Rate on U1 612' Outer Door Seal Too High
- AR 2012-5042, 2-IRV-111 Control Valve has an Air Leak
- AR 2012-5138, Ice Condenser IDD 6-C Exceeded Opening Force
- AR 2012-6083, U1 Lower Containment Airlock AF Outer Door Leakage >500sccm
- OHI 6060, 2CD Emergency Diesel Generator Logs, April 15, 2012
- OHI-6080, 2AB Emergency Diesel Generator Logs, April 5, 2012
- WO 55393737-04, 2-HV-CCW-B, PMT Leak Inspection, March 30, 2012
- WO 55402185-02, 2-IRV-111 Control Valve PMT, April 20, 2012

1EP6 Drill Evaluation

- AR 2012-2258, Midas Meteorological Data Channels Indicating Bad Quality
- EMD-32a, Michigan State Police, Nuclear Plant Event Notification, January 12, 2012
- PMP-2080-EPP-101, Emergency Classification, Revision 15
- WO55399221-01, Midas Meteorological Data Channels, March 19, 2012

4OA1 Performance Indicator Verification

- AR 2011-4727, Incorrect Data in ROP Performance Indicator Documentation
- AR 2011-7391, MSPI Report Submitted Last Quarter with an Error
- AR 2011-7723, Apparent Discrepancy in ROP Performance Indicator Data
- AR 2012-4847, Two Errors in Data for ROP Performance Indicator
- AR 2012-7306, Missed EDG Maintenance Rule / MSPI Unavailability
- GT 2011-7436, TDAFP Maintenance Rule Issues During STP-017T

- PMP-7110-PIP-001, Reactor Oversight Program Performance Indicators and Monthly Operating Report Data, Unit 1/2, Mitigating System Performance Index, Second Quarter 2011 Through First Quarter 2012, Cooling Water Systems, Residual Heat Removal Systems, High Pressure Safety Injection System, Emergency AC Power Systems, Auxiliary Feedwater System

4OA2 Problem Identification and Resolution

- 1st Quarter 2012 Trend Report
- 4th Quarter 2011 Trend Report
- AR 2011-14767, Potential Trend: C7a1- Modification Configuration Issues
- AR 2011-14772, Equipment Deficiencies that Affect the Reactivity Management
- AR 2011-3556, Adverse Trend:E8a4 (Other Equipment Symptoms)
- AR 2012-0317, Casual Evaluation – Status Control
- AR 2012-1492, Cognitive Trend on January 2012 Plant Safety Performance
- AR 2012-3440, Cognitive Trend of Human Performance Reason Code Use
- Reason Codes Definitions and Limits, March 12, 2011

4OA3 Followup of Events and Notices of Enforcement Discretion

- 2-OHP-4023 ES-0.1, Reactor Trip Response, Revision 27
- AR 2012-2189, U1 NI Power Range Drawer Cal Came into Question
- AR 2012-2274, Critical Parameters Found Out of Tolerance
- AR 2012-5743, Missing/Loose Bolts on Control Valve B
- AR 2012-5744, U2 Generator Trip/Turbine Trip Which Caused a Reactor Trip
- AR 2012-5746, Closed U2 MSIVs Due to Cool Down Following Reactor Trip
- AR 2012-5783, 2-URV-110 Steam Dump is Leaking By
- PMP-4010-TRP-001, April 30, 2012 Unit 2 Reactor Trip Review, May 1, 2012
- PMP-2291-PLN-001, Work Control Activity Planning Process, rev 046

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AR	Action Request
ASME	American Society of Mechanical Engineers
BA	Boric Acid
CAP	Corrective Action Program
CFR	Code of Federal Regulations
EC	Engineering Change
ET	Eddy Current\
IMC	Inspection Manual Chapter
IP	Inspection Procedure
ISI	Inservice Inspection
LCD	Liquid Crystal Diode
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MSPI	Mitigating System Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PI	Performance Indicator
RCS	Reactor Coolant System
RFO	Refueling Outage
SDP	Significance Determination Process
SG	Steam Generator
SRA	Senior Reactor Analyst
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Examination
WO	Work Order

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Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket Nos. 50-315; 50-316
License Nos. DPR-58; DPR-74

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Letter to L. Weber from J. Giessner dated August 2, 2012.

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2 – NRC INTEGRATED INSPECTION REPORT 05000315/2012003 and 05000316/2012003

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