January 20, 2004

Mr. M. Nazar
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000315/2003012;
05000316/2003012

Dear Mr. Nazar:

On December 31, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your D. C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on January 8, 2004, with you and other members of your staff.

This 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.

Based on the results of this inspection, two findings of very low safety significance (Green) were identified which involved violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the D. C. Cook Nuclear Power Plant.

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Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 6
Division of Reactor Projects

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

Enclosure: Inspection Report 05000315/2003012; 05000316/2003012
w/Attachment: Supplemental Information

cc w/encl: J. Jensen, Site Vice President
M. Finissi, Plant Manager
R. Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
Emergency Management Division
MI Department of State Police
D. Lochbaum, Union of Concerned Scientists

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-315; 50-316
License Nos:	DPR-58; DPR-74
Report No:	05000315/2003012; 05000316/2003012
Licensee:	Indiana Michigan Power Company
Facility:	D. C. Cook Nuclear Power Plant, Units 1 and 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	October 1, 2003, through December 31, 2003
Inspectors:	B. Kemker, Senior Resident Inspector I. Netzel, Resident Inspector M. Holmberg, Senior Reactor Engineer, Region III L. James, Operations Engineer, NRR B. Jorgensen, Operations Engineer, Region III J. Lennartz, Senior Resident Inspector, Palisades F. Ramirez, Reactor Engineer, Region III H. Walker, Senior Reactor Engineer, Region III
Approved by:	Eric R. Duncan, Chief Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000315/2003012, IR 05000316/2003012; 10/01/2003-12/31/2003; D. C. Cook Nuclear Power Plant, Units 1 and 2; Inservice Inspection; Surveillance Testing.

This report covers a 13-week period of inspection by resident, regional, and headquarters based inspectors. Two Green findings were identified with associated Non-Cited Violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after 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 3, dated July 2000.

A. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Barrier Integrity

- Green. The inspector identified a Non-Cited Violation of 10 CFR 50.55a(g)(4) associated with use of a non-Code calibration block for calibration of equipment used in ultrasonic examinations of the reactor vessel-to-flange welds for Unit 1 and Unit 2. Specifically, the calibration block exceeded the American Society of Mechanical Engineers (ASME) Code specified thickness, did not have reflectors (side drilled holes) located at the required locations and did not contain square notch type reflectors.

  This finding was more than minor because it could have become a more significant safety concern if not corrected. Specifically, the licensee had scheduled an ultrasonic examination of the vessel-to-flange weld during the current outage and intended to use the non-Code calibration block. Had this issue not been identified, it would have resulted in a non-Code examination, which could have resulted in undetected weld flaws remaining in-service (e.g., a degraded reactor coolant system boundary). The finding was of very low safety significance because other examinations of the reactor vessel-to-flange welds had been conducted in accordance with the Code. To address this issue, the licensee planned to generate procedures to better control the process for these types of inspections. (Section 1R08)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Non-Cited Violation of Technical Specification 6.8.1.a associated with the licensee's failure to adequately implement the requirements of 12-MHP-4030-031-001, "Inspection of Lower Containment and Recirculation Sumps." Specifically, the licensee failed to adequately perform the following: (1) check the lower containment sump screen wire mesh for rips, tears, openings, or gaps that were large enough to allow particulate larger than 1/4 inch to pass through or around screens; (2) perform a visual examination of residual heat removal pump suction piping from the recirculation sump to the suction valve discs for debris greater than 1/4 inch in diameter; (3) check recirculation sump level instrumentation well lateral support bracket mounting nuts for evidence of abnormal deterioration; and (4) accurately identify and record the degradation of galvanized coatings on carbon steel fasteners for the recirculation sump level instrumentation well lateral support brackets. The licensee subsequently corrected these conditions prior to Unit 1 entering Mode 4.

The inspectors determined that a failure to correct these surveillance test procedure implementation inadequacies could become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to adequately perform surveillance testing could result in the failure to identify degraded or inoperable safety-related equipment. The inspectors concluded that this finding was a licensee performance deficiency of very low safety significance because the recirculation sump was not required to be capable of performing a safety-related function immediately following the inadequate surveillance testing and the conditions were corrected prior to Unit 1 entering Mode 4. (Section 1R22)

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

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power until October 18, 2003, when the licensee conducted a reactor shutdown for the Cycle 19 refueling outage (U1C19). Following completion of the refueling outage, the licensee synchronized the unit to the grid on November 26, 2003. Unit 1 operated at or near full power for the remainder of the period.

Unit 2 operated routinely and at or near full power with the following exceptions:

- On December 10, 2003, the licensee received approval of an emergency license amendment to extend the 72-hour allowed action time of Technical Specification (TS) 3.8.1.1.b to preclude shutting down Unit 2 until the AB emergency diesel generator (EDG) could be restored to an operable status.

- On December 14, 2003, the licensee reduced power to approximately 2 percent of rated thermal power to repair a main feedwater regulating valve. Unit 2 was returned to full power on December 16, 2003.

- On December 19, 2003, the licensee activated the Emergency Plan at the Unusual Event level due to a leak of approximately 30 gallons-per-minute from a seal water injection filter on Unit 2. The leaking filter was isolated and the licensee subsequently terminated the Unusual Event. Unit 2 remained stable at full power during the event. (Section 40A3.3)

- On December 30, 2003, Unit 2 experienced an automatic reactor trip due to the unplanned closure of the number 22 and 23 steam generator feedwater isolation valves. The feedwater isolation valve closure originated from an abnormality in the control room instrument distribution (CRID) 120 volt alternating current (AC) power system. Technicians were landing leads on a residual heat removal (RHR) system flow transmitter which was powered from the affected CRID power supply at the time of the event. An arc was observed during the lead landing procedure. Unit 2 was restarted and synchronized to the grid on January 4, 2004. (Section 40A3.4)

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed the licensee's procedures and preparations for cold weather conditions, and performed general area walkdowns. This activity represented one inspection sample.

During general pre-winterization walkdowns conducted the weeks of November 3, 2003, and November 10, 2003, the inspectors toured selected buildings and areas to verify the licensee had identified all discrepant conditions such as damaged doors, windows, or vent louvers. Additionally, the inspectors observed housekeeping conditions and verified that materials capable of becoming airborne missile hazards during high wind conditions were appropriately located and restrained. The inspectors also verified that outside water storage tanks (refueling water storage tanks, primary water storage tanks, and condensate storage tanks) and associated valve houses and piping had no missing or damaged insulation and were serviced by operable heat trace circuits.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. The inspectors performed three partial system walkdowns of the following risk significant systems:

- Unit 2 East Component Cooling Water (CCW) System on December 3, 2003, (risk significant with Unit 2 West CCW train out of service for maintenance)
- Unit 1 East Essential Service Water (ESW) System on October 12, 2003, through October 14, 2003, (risk significant during Unit 1 West ESW pump replacement)
- Spent Fuel Pool Cooling System on November 13, 2003, (risk significant immediately following Unit 1 core off-load during refueling)

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones. The inspectors reviewed operating procedures, system diagrams, TS requirements, Administrative TSs, 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 were aligned correctly.

In addition, the inspectors verified that equipment alignment problems were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours

a. Inspection Scope

The inspectors performed 10 fire protection walkdowns of the following risk significant plant areas:

- Unit 1 Control Room Heating, Ventilation, and Air Conditioning Equipment Room (Zone 70)
- Unit 2 Control Room Heating, Ventilation, and Air Conditioning Equipment Room (Zone 73)
- Unit 1 RHR Heat Exchanger Rooms (Zones 44C and 44D)
- Unit 2 RHR Heat Exchanger Rooms (Zones 44G and 44H)
- Unit 2 Turbine Building 591' Elevation (Zones 84 through 89)
- Unit 1 and 2 Auxiliary Building East 633' Elevation (Zone 51)
- Unit 1 and 2 Auxiliary Building West 633' Elevation (Zone 52)
- Unit 1 Turbine Building 591' Elevation (Zones 79 through 83)
- Unit 1 Containment Building Upper Volume (Zone 76)
- Unit 2 Auxiliary Building 650' Elevation (Zone 69)

The inspectors verified that fire zone conditions were consistent with assumptions in the licensee's Fire Hazards Analysis. The inspectors walked down fire detection and suppression equipment, assessed the material condition of fire fighting equipment, and evaluated the control of transient combustible materials. In addition, the inspectors verified that fire protection related problems were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

a. Inspection Scope

The inspectors performed one inspection activity related to the licensee's precautions to mitigate the risk from internal flooding events. The inspectors reviewed six flooding related issues that the licensee recently entered into their corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's proposed corrective actions and completed corrective actions for these issues and verified that identified problems were appropriately addressed.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspector evaluated the implementation of the licensee's Inservice Inspection Program for monitoring degradation of the reactor coolant system (RCS) boundary and risk significant piping system boundaries, based on the review of nondestructive examination records.

The inspector reviewed licensee records related to volumetric and visual nondestructive examination activities completed on the reactor vessel-to-flange weld, Unit 1 steam generator No. 14 U-tubes, and other Code Class 1 system components to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI and TS requirements, and to verify that identified indications and defects were dispositioned in accordance with the ASME Code. The inspector concluded that this review constituted two inspection samples as described in Section 71111.08-5 of Inspection Procedure 71111.08, "Inservice Inspection Activities."

The inspector reviewed licensee records related to pressure boundary welding at valves 2-FW-118-4 and 1-MRV-210 (Class 2 components) to verify that the welding acceptance (e.g., radiography (if applicable), pressure testing, tensile tests, bend tests or Charpy impact tests) and pre-service examinations were performed in accordance with ASME Code Section III, Section V, Section IX, and Section XI. The inspector concluded that this review constituted one inspection sample as described in Section 71111.08-5 of Inspection Procedure 71111.08, "Inservice Inspection Activities."

The inspector reviewed licensee records associated with ASME Section XI Code replacement activities for Code Class 1 valves 1-SI-161-L1 and 1-SI-158-L1 to verify that ASME Code Section III, Section V, and Section XI requirements were met. The inspector concluded that this review constituted one inspection sample as described in Section 71111.08-5 of Inspection Procedure 71111.08, "Inservice Inspection Activities."

The inspector reviewed the steam generator tube eddy current examination scope and expansion criteria, eddy current data acquisition and analysis procedures, and the eddy current examination reports for the Unit 1 steam generator No. 14 to confirm that TS requirements were met; the inspection was consistent with Electric Power Research Institute Guidelines; areas of potential degradation were inspected; and eddy current probes and equipment were qualified in accordance with the Electric Power Research Institute Guidelines for the expected types of tube degradation.

The inspector concluded that the review discussed above could not be credited as a completed inspection sample as described in Section 71111.08-5 of Inspection Procedure 71111.08, "Inservice Inspection Activities." The specific activities that were not available for review to complete this inspection sample and other procedure samples are identified in the table below.

Inspection Procedure 7111108 Section Number	Reason Activity Was Unavailable for Inspection	Reduction in Inspection Procedure Samples
Section 02.01.c: associated with review of examinations from the previous outage with recordable indications that have been accepted by the licensee for continued service.	The licensee reported that no recordable indications were accepted for continued service for Unit 1 following inspections conducted during the prior refueling outage.	The inspector concluded that this constituted a reduction of one from the total number of procedure samples required by Section 71111.08-5 of Inspection Procedure 71111.08.
Section 02.02.a 1-4: associated with review of licensee in-situ pressure testing of steam generator tubes.	The licensee did not identify any tubes that required pressure testing.	The inspector concluded that this constituted a reduction by one from the total number of procedure samples required by Section 71111.08-5 of Inspection Procedure 71111.08.
Section 02.02.f & g: confirmed that all repair processes used were approved in the TSs for use at the site; reviewed tube repair criteria.	The licensee did not identify any tubes that required repair.	
Section 02.02.h: associated with steam generator tube leakage greater than 3 gallons per day.	The licensee reported that no steam generator tube leakage had been observed.	
Section 02.02.j: associated with assessment of corrective actions for loose parts or foreign material discovered on the secondary side of the steam generator.	The licensee did not report any loose parts in the No. 14 steam generator based upon eddy current testing.	
Section 02.02.k: associated with review of one to five samples of eddy current data.	The inspector did not identify any "serious questions" regarding the eddy current data.	

b. Findings

b.1 Non-Code Calibration Block Used For Examination of Reactor Vessel-to-Flange Welds

Introduction

One finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR 50.55a(g)(4) was identified when licensee personnel failed to use an appropriate Code calibration block to calibrate ultrasonic testing (UT) equipment used to examine reactor vessel-to-flange welds for Unit 1 and Unit 2.

Description

On October 22, 2003, the inspector identified that the UT calibration block which the licensee intended to use for the Unit 1 refueling outage to support Procedure 52-SI-87-10, "Ultrasonic Examination of Reactor Vessel to Flange Welds from Flange Top Surface," was not constructed in accordance with ASME Code, Section V, Article 4 requirements. Specifically, the calibration block on drawing 90D0087, "Vessel Flange To Shell Ultrasonic Calibration Block," exceeded Code specified thickness, did not have reflectors (side drilled holes) located at the required locations and did not contain square notch type reflectors. Further, the licensee had not demonstrated this UT examination method as an alternative to the Code technique as required by IWA-2240 of Section XI to the Authorized Nuclear Inservice Inspector. To address the inspector’s concerns, the licensee deferred the Unit 1 vessel-to-flange weld examination which had been scheduled to begin on October 25, 2003. The licensee deferred this examination in accordance with NRC approved Code Case N-623, which allowed deferring this examination until the end of the Code inspection interval (2009). However, the licensee had previously performed UT examinations of the vessel-to-flange weld for Unit 1 and Unit 2 during the previous Code interval using this non-Code calibration block. The inspector considered the failure to meet the Code requirements or seek an approved alternative to be a licensee performance deficiency warranting a significance evaluation.

On April 19, 1989, the licensee performed a UT examination of the Unit 1 vessel-to-flange welds using Procedure SWRI-NDT-700-11, "Mechanized Ultrasonic Inside Surface," and used a calibration block identified on drawing D-3378-609, "Vessel Flange To Shell UT Calibration Block," Revision 10.

On June 12, 1988, the licensee performed a UT examination of the Unit 2 vessel-to-flange welds using Procedure SWRI-NDT-700-11, "Mechanized Ultrasonic Inside Surface," and used a calibration block identified on drawing D-3378-609, "Vessel Flange To Shell UT Calibration Block," Revision 10.

For each of these UT examinations, the licensee used a calibration block that was 40 inches thick (from the clad face of the block). Based upon the thickness of the weld under examination (10.75 inches), the calibration block was required by the ASME Code, Section V, Article 4, to be 10.75 inches to 11.0 inches thick. This block was also required by Article 4 to have side drilled holes placed at 1/4, ½, and 3/4 of the calibration block thickness. However, the licensee's calibration block was not consistent with this requirement in that it contained holes at approximately ½, 3/4, and 7/8 of the calibration block thickness. Further, the licensee's calibration block did not contain square notch reflectors as specified by Article 4. The purpose and location of the side drilled holes was to allow the licensee to establish a distance amplitude correction curve for the ultrasonic equipment to ensure that weld defects (e.g., cracks) could be detected. Further, the square notch reflector was required to be located at the near and far sides of the calibration block and served to confirm (for angle beam examinations) the ability to detect cracking initiated near the surface of the vessel wall or under the vessel cladding.

The licensee documented the use of the non-Code calibration block in condition report (CR) 03295057. The licensee's planned corrective actions discussed in CR 03295057 included creating procedures to control the process for identifying, performing, and documenting alternative examinations in accordance with Paragraph IWA-2240 of ASME Code Section XI. Additionally, the licensee intended to review documentation for other UT calibration blocks to confirm that Code requirements were met.

Analysis

The inspector determined that the use of a non-Code calibration block to perform weld examinations was a performance deficiency warranting a significance evaluation. The inspector reviewed this finding against the guidance contained in Appendix B, "Issue Dispositioning Screening," of Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports." In particular, the inspector compared this finding to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 612 to determine whether the finding was minor. Following that review, the inspector concluded that none of the examples listed in Appendix E accurately represented this example. As a result, the inspector compared this performance deficiency to the minor questions contained in Section C, "Minor Questions," in Appendix B of IMC 0612. The inspector determined that this finding had the potential to impact the Barrier Integrity cornerstone. The inspector concluded this finding was greater than minor because if left uncorrected, it would have become a more significant safety concern. Specifically, the licensee had scheduled a UT examination of the vessel-to-flange weld during the current outage and intended to use this non-Code calibration block. Had the inspector not identified this issue, it would have likely resulted in a non-Code UT examination, which could have resulted in undetected weld flaws remaining in service (e.g., a degraded RCS boundary).

The inspector reviewed past examinations and confirmed that additional examinations of the reactor vessel-to-flange welds had been conducted from the inside diameter of the vessel in 1995 for Unit 1 and 1996 for Unit 2. The licensee performed these examinations using demonstrated UT techniques consistent with Appendix VIII of Section XI of the ASME Code. The licensee had used this demonstrated technique as an approved alternative to the Code to the Authorized Inservice Inspector in accordance with Paragraph IWA-2240 of Section XI. Because this type of examination would have detected flaws in this weld, and no rejectable flaws were detected, this issue did not represent an actual degradation in the pressure boundary integrity.

The inspector evaluated this finding using Inspection Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening associated with the Barrier Integrity cornerstone. The inspector concluded that this finding did not result in an actual degradation of the RCS barrier. Therefore, the inspector determined that this issue was a finding of very low safety significance (Green).

Enforcement

10 CFR 50.55a(g)4 required, in part, that throughout the service life of a pressurized water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet the requirements of Section XI. Section XI (1983 Edition, with 1983 Addenda), Paragraph IWA-2232, required that the "ultrasonic examination of welds in ferritic material greater than 2 inches in thickness shall be conducted in accordance with Article 4 of Section V..." The ASME Code, Section V, Paragraph T-434.2.1, required for the calibration block "a square notch shall also be used" and Paragraph T-434.3 required "Figure T-434.1 shows block configuration with hole size and location. Each weld thickness on the component must be represented by a block having thickness relative to the component weld as shown in Figure T-434.1." The thickness of the flange to shell weld was 10.75 inches as shown on Drawing 232-442-6, "Pressure Vessel Welding and Machining," Revision 6.

Contrary to these requirements, on April 19, 1989, the licensee performed a calibration for UT examination of the vessel-to-flange weld (reference examination summary sheet No. 002600) and used a calibration block (reference drawing D-3378-609, "Vessel Flange to Shell UT Calibration Block," Revision 10) that exceeded the maximum Code specified thickness, did not have the reflectors (side drilled holes) located at the required locations and did not contain square notch type reflectors. The licensee's failure to use a calibration block as described in the Code was an example where the requirements of 10 CFR 50.55a(g)(4) were not met and was a violation.

Contrary to these requirements, on June 12, 1988, the licensee performed a calibration for UT examination of the vessel-to-flange weld (reference examination summary sheet No. 560011) and used a calibration block (reference drawing D-3378-609, "Vessel Flange to Shell UT Calibration Block," Revision 10) that exceeded the maximum Code specified thickness, did not have the reflectors (side drilled holes) located at the required locations, and did not contain square notch type reflectors. The licensee's failure to use a calibration block as described in the Code was an example where the requirements of 10 CFR 50.55a(g)(4) were not met and is a violation.

However, because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (CR 03295057), it is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000315/2003012-01; 05000316/2003012-01).

To address this issue, licensee personnel planned to create procedures to control the process for identifying, performing, and documenting alternative examinations in accordance with the ASME Code.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors assessed licensed operator performance and the training evaluators' critique during licensed operator re-qualification evaluations in the D. C. Cook operations training simulator on December 9, 2003. The inspectors focused on alarm response, command and control of crew activities, communication practices, procedural adherence, and the implementation of emergency plan requirements.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following two risk-significant structures, systems, and components (SSCs):

- Unit 1 Containment Spray (CTS) Discharge Valves ICM-220 and ICM-221
- Unit 1 AB EDG Relay 1-27-T11A-1 Failure

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the SSCs. Specifically, the inspectors independently verified the licensee's actions to address SSC performance or condition problems in terms of the following:

- appropriate work practices,
- identifying and addressing common cause failures,
- scoping of SSCs in accordance with 10 CFR 50.65(b),
- characterizing SSC reliability issues,
- tracking SSC unavailability,
- trending key parameters (condition monitoring),
- 10 CFR 50.65(a)(1) or (a)(2) classification and/or re-classification, and
- appropriate performance criteria for SSCs classified as (a)(2) and/or appropriate and adequate goals and corrective actions for SSCs classified as (a)(1).

In addition, the inspectors verified that maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for seven maintenance and operational activities affecting the following equipment:

- Unit 1 East ESW Train Maintenance with an Emergent Activity on the East Charging Pump Breaker
- Unit 1 RCS Draindown to Below the Reactor Vessel Flange and Transition to Refueling Mode
- Unit 1 345 Kilovolt (kV) Transformer 5 Maintenance
- Unit 1 East CCW Train and CD EDG Maintenance
- Unit 1 CD EDG Maintenance with Refueling Activities
- Unit 2 West CCW Train Maintenance
- Unit 2 AB EDG Maintenance

These activities were selected based on their potential risk significance relative to the reactor safety cornerstones. The maintenance associated with the Unit 1 East charging pump breaker was emergent work to replace a failed breaker that would not open from the Control Room. The Unit 2 AB EDG maintenance activity was emergent work to replace a failed electronic governor module and a fuel injector that failed during testing. The licensee requested and received an emergency license amendment to extend the 72-hour allowed action time of TS 3.8.1.1.b to preclude shutting down Unit 2 until the AB EDG could be restored to an operable status.

As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst and/or shift technical advisor, and verified that 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 that risk analysis assumptions were valid and applicable requirements were met.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions (71111.14)

.1 Unit 1 East Charging Pump Breaker Would Not Trip From the Control Room

a. Inspection Scope

On September 30, 2003, control power was lost to the operating Unit 1 East centrifugal charging pump resulting in a letdown isolation and the inability to trip the pump from the Control Room. The pump was subsequently tripped locally. The inspectors observed operator response to the off-normal condition, as well as follow up actions to determine the cause of the failure and the extent of condition.

b. Findings

No findings of significance were identified.

.2 Compensatory Measures for Potential Solar Magnetic Disturbances

a. Inspection Scope

On October 29, 2003, the inspectors reviewed the licensee's preparations for anticipated solar magnetic disturbances to assess readiness for potential problems that could have been encountered during the solar flare activity. In particular, the inspectors focused on planned or unplanned activities that could have reduced the reliability of on-site and off-site electrical power sources.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following nine CRs to ensure that either the condition did not render the involved equipment inoperable or result in an unrecognized increase in plant risk, or the licensee appropriately applied TS limitations and appropriately returned the affected equipment to an operable status.

- Condition Report 03158021, "Examination of Previously Installed 1E and 2E ESW Pump Bowls Identified Bearing Damage and Adhesion of Bearing Material to the Pump Shaft"
- Condition Report 02290012, "Capability Calculations Show that Under Certain Conditions (Reduced Pressure in the 85 Psig [pounds per square inch gauge] Header to 80 Psig) the Steam Generator Power Operated Relief Valves Have Almost No Positive Margin"
- Condition Report 03016037, "Found Open Coil on Time Delay Relay for Safety Injection"
- Condition Report 03290060, "Unit 1 TDAFP [Turbine Driven Auxiliary Feedwater Pump] Did Not Pass Flow Acceptance Criteria"
- Condition Report 03310041, "Vibration Sensor Tubing Pieces Installed on Circulating Water Pump No.13 Found Throughout the Condenser," and Condition Report 03286004, "One Vibration Sensor Tubing Clamp Missing and Two Others Rusted to the Point of Falling Off the Unit 1 West ESW Pump"
- Condition Report 03310043, "Non-Safety Related Bolt and Nut Installed in Safety Related Reactor Vessel Support"
- Condition Report 03305015, "Modes 1-4 Aggregate Operability Determination for Unit 1"
- Condition Report 03320061, "In the Unit 1 Recirculation Sump, Corrosion Was Found on Pipe Stantion Mounting Bolting at Floor, Missing Bolting on Pipe Stantion Mounts at Floor of Sump"

- Condition Report 03282025, "An Aluminum Work Plate Was Taken into Unit 1 Containment"

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Review of Selected Operator Workarounds

a. Inspection Scope

The inspectors evaluated the operator work-around (OWA) listed below to identify any potential affect on the functionality of mitigating systems or on the operators' response to initiating events:

- Shutdown Bank 'A' Rods C05, E09, and Shutdown Bank 'B' Rod N07 Indicated Greater than 18 Steps from Group on Plant Process Computer During Reactor Startup Following 01-IHP-6030-IMP-022, "Analog Rod Position Indication (NARPI) System Functional Test and Linearization"

The inspectors selected this issue to review as a potential OWA in order to understand the conditions causing the anomalous rod position indications and the potential effect on plant operations. The inspectors interviewed operating and engineering department personnel and reviewed selected procedures and documents.

b. Findings

No findings of significance were identified.

.2 Semiannual Review of the Cumulative Effect of Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effect of OWAs, control room deficiencies, and degraded conditions on equipment availability, initiating event frequency, and the ability of the operators to implement abnormal or emergency operating procedures. In particular, the cumulative effects of OWAs on the following attributes were considered:

- the reliability, availability, and potential for mis-operation of a system;
- the ability of operators to respond to plant transients or accidents in a correct and timely manner; and
- the potential to increase an initiating event frequency or affect multiple mitigating systems.

In addition, the inspectors reviewed the issues that the licensee entered into their corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for issues potentially affecting the functionality of mitigating systems or on the operators' response to initiating events that were documented in selected CRs.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed four post maintenance testing activities associated with the following scheduled maintenance:

- Unit 1 AB EDG Voltage Regulator Replacement
- Unit 1 CD EDG Electric Governing Module Replacement
- Unit 1 East CCW Train Maintenance (Valve 1-CCW-178E Repair/Replacement and Heat Exchanger Cleaning)
- Unit 1 Valve 1-IMO-315 (Injection to Hot Legs 1 and 4)

The inspectors reviewed the scope of the work performed and evaluated the adequacy of the specified post maintenance testing. The inspectors verified that the post maintenance testing was performed in accordance with approved procedures, that the procedures clearly stated acceptance criteria, and that the acceptance criteria were met. The inspectors interviewed operations, maintenance, and engineering department personnel and reviewed the completed post maintenance testing documentation.

In addition, the inspectors verified that post maintenance testing problems were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Unit 1 Refueling Outage (U1C19)

a. Inspection Scope

The inspectors evaluated the licensee's conduct of Unit 1 refueling outage activities to assess the licensee's control of plant configuration and management of shutdown risk. The inspectors reviewed configuration management to verify that the licensee maintained defense-in-depth commensurate with the shutdown risk plan; reviewed major outage work activities to ensure that correct system lineups were maintained for key mitigating systems; and observed refueling activities to verify that fuel handling operations were performed in accordance with the TSs and approved procedures. Other major outage activities evaluated included the licensee's control of the following:

- SSCs which could cause unexpected reactivity changes;
- flow paths, configurations, and alternate means for RCS inventory addition and control of SSCs which could cause a loss of inventory;
- RCS pressure, level, and temperature instrumentation;
- containment penetrations;
- spent fuel pool cooling during and after core offload;
- switchyard activities and the configuration of electrical power systems; and
- SSCs required for decay heat removal.

The inspectors observed portions of the plant cooldown, including the transition to shutdown cooling, to verify that the licensee controlled the plant cooldown in accordance with the TSs. The inspectors also observed portions of the restart activities to verify that TS requirements and administrative procedure requirements were met prior to changing operational modes or plant configurations. Major restart inspection activities performed included:

- verification that RCS boundary leakage requirements were met prior to entry into Mode 4 and subsequent operational mode changes;
- verification that containment integrity was established prior to entry into Mode 4;
- inspection of the Containment Building, including the ice condenser, to assess material condition and search for loose debris, which if present could be transported to the containment recirculation sumps and cause restriction of flow to the ECCS pump suctions during accident conditions;
- verification that the material condition of the Containment Building ECCS recirculation sumps met the requirements of the TSs and was consistent with the design basis; and

The inspectors interviewed operations, engineering, work control, radiological protection, and maintenance department personnel and reviewed selected procedures and documents.

In addition, the inspectors verified that refueling problems were entered into the corrective action program with the appropriate significance characterization. The inspectors also reviewed the licensee’s corrective actions for refueling outage issues documented in selected CRs.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed portions of the following eight surveillance testing activities and/or reviewed the test results to determine whether risk significant systems and equipment were capable of performing their intended safety function and to verify that testing was conducted in accordance with applicable procedural and TS requirements.

- 01-EHP-4030-109-237, "CTS and RHR Check Valve Leak Rate Test," performed on October 22 and 23, 2003
- 01-OHP-4030-119-022E, "East Essential Service Water System Test," performed on October 1, 2003
- 12-MHP-4030-031-001, "Inspection of Lower Containment and Recirculation Sumps," performed on November 16, 2003
- 1-OHP-4030-132-217B, "DG1AB Load Sequencing and ESF [Engineered Safety Feature] Testing," performed on October 20 and 21, 2003
- 01-OHP-4030-156-017CS, "Main and Auxiliary Feedwater System Shutdown Testing," Attachment 1, "TDAFP Check Valve Test," performed on October 17, 2003
- 01-OHP-4030-103-008R, "ECCS Check Valve Test," performed on October 25, 2003
- 01-IHP-4030-STP-100, "Response Time Testing," performed on October 14, 2003
- 12-THP-6020-CHM-106, "Ice Condenser," performed on November 14 and 15, 2003

The inspectors reviewed the test methodology and test results to verify that equipment performance was consistent with safety analysis and design basis assumptions.

In addition, the inspectors verified that surveillance testing problems were being entered into the corrective action program with the appropriate significance characterization.

b. Findings

b.1 Failure to Adequately Implement Requirements of the Unit 1 Lower Containment and Emergency Core Cooling System (ECCS) Recirculation Sumps Surveillance Test Procedure

Introduction

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of TS 6.8.1.a when the licensee failed to adequately implement the surveillance test inspection requirements for the Unit 1 ECCS recirculation sump and lower containment sump.

Discussion

On November 16, 2003, the inspectors examined the exterior of the lower containment sump and performed a final closeout (interior and exterior) inspection of the ECCS recirculation sump. This inspection was performed just prior to Unit 1 entering Mode 4 when the ECCS was required to be operable. The inspectors identified several instances where the licensee failed to correctly implement procedural requirements for conducting the sump inspections, including the following:

- The inspectors examined the lower containment sump screen wire mesh located between the floor and cover plate and identified small gaps at the top of the left screen section and the bottom of the right screen section approximately 2 inches in length with approximately 1/4-inch gap openings. These gaps would potentially allow particulate larger than 1/4 inch to pass. Irregular bends in the wire mesh or bends from damage created gaps between the straight surfaces. The inspectors discussed these observations with the licensee. The licensee initiated CR 03320060 to address the deficiencies identified with the screens.

- The inspectors identified that the mounting anchor bolts, nuts and washers for the abandoned level instrumentation standpipe mounts in the bottom of the recirculation sump were corroded. These fasteners were constructed of carbon steel and there was significant pitting and wastage present due to boric acid corrosion. These fasteners were intended to have a galvanized coating to protect them from corrosion, however the coating was no longer present. The inspectors were concerned that if the fasteners broke as a result of corrosion, pieces could be swept into the RHR pumps during an accident and cause these pumps to fail. The inspectors noted that one bolt, nut, and washer was missing from each of three standpipe mounts at the floor of the sump. The licensee had previously evaluated this condition in CR 02150019 and concluded that it was acceptable. The inspectors discussed these observations with licensee personnel. The licensee initiated CR 03320061 and CR 03322049 to address the deficiencies identified with the corroded fasteners.

- The inspectors attempted to visually examine the valve discs for recirculation sump isolation valves 1-ICM-305 and 1-ICM-306 through the open end of the piping. However, the piping was filled with water and the valve discs were not visible using a flashlight. The inspectors noted that since foreign material exclusion controls were not in place, if foreign material were present in the piping, it could affect operation of the RHR pumps or restrict system flow. The inspectors discussed these observations with the licensee. The licensee initiated CR 03322049 to address the deficiencies with the valve inspection.

- The inspectors also noted that the condition of the sump walls and floor coating was degrading as evidenced by significant flaking and/or peeling of the coating. This had been previously identified by the licensee and most of the loose coatings had been removed. The inspectors discussed these observations with the licensee. The licensee initiated CR 03322049 and CR 03324004 to address the wall and floor coating deficiencies.

Technical Specification 3.5.2 required the ECCS recirculation sump to be operable in Modes 1, 2, 3 and 4. Technical Specification 4.5.2.d.2 required the licensee to visually inspect the sump and verify that the subsystem suction inlets were not restricted by debris and that the sump components, such as trash racks and screens, showed no evidence of structural distress or abnormal corrosion. The purpose of the sump inspection was to verify the long term cooling capability of the ECCS in the recirculation mode during the accident recovery period following a loss of coolant accident. There were no similar TS requirements for the lower containment sump. The licensee satisfied the requirements of TS 4.5.2.d.2 by performing Procedure 12-MHP-4030-031-001, "Inspection of Lower Containment and Recirculation Sumps." The licensee developed Design Information Transmittal S-00408-00, "Containment Recirculation Sump and

Lower Containment Sump Inspection Requirements," to establish the bases for the procedural requirements and acceptance criteria included in 12-MHP-4030-031-001.

The inspectors examined the completed surveillance test procedure for the Unit 1 ECCS recirculation sump and the lower containment sump (12-MHP-4030-031-001) and reviewed Design Information Transmittal S-00408-00. Based on the above observations, the inspectors identified several issues with the completed procedure.

- The maintenance craftsman who performed the lower containment sump inspection on November 15, 2003, noted that there was a small gap at the top of the left outer screen section approximately 2 inches in length with approximately 1/4-inch gap opening. He noted the same at the bottom of the right outer screen section. This corresponded with the inspectors' observations the following day. Apparently this condition was not considered to be unacceptable, although Procedure Step 4.1.4 stated that the inspection was intended to identify rips, tears, openings or gaps that were large enough to allow particulate larger than 1/4 inch to pass through or around the screens. The maintenance supervisor lined out an "N/A" in Step 7.2.4 (testing complete and acceptance criteria has not been met) on November 19, 2003, to note that the screen gaps may be excessive and referenced CR 0332060 that was written based on the inspectors' identification of openings in the sump screens. The licensee initiated Job Order 03320060-01 to correct the deficiencies. Based on a review of the documentation in the completed job order, it was unclear to the inspectors if the identified deficiencies were actually corrected. The maintenance craftsman wrote on November 18, 2003, that he measured for openings greater than 1/4 inch and none were observed. He added that he reinspected the screens with engineering and verified that conditions were satisfactory with no openings greater than 1/4 inch. The licensee initiated CR 03349055 to address this concern. Because there was a 3/16-inch mesh screen between the lower containment sump and the recirculation sump, the identified condition did not affect the operability of the ECCS.

- The maintenance craftsman who performed the recirculation sump inspection on November 15, 2003, noted in Step 4.2.4 that he found no debris in the suction piping for isolation valves ICM-305 and ICM-306. Design Information Transmittal S-00408-00 stated that the inspection shall include an examination of the interior of the 18-inch diameter pipes exiting the rear chamber of the recirculation sump for the presence of debris greater than 1/4 inch in diameter. This may be performed with remote observation equipment, (e.g., boroscope, etc.). If this inspection was to be performed visually, the lighting necessary to perform this inspection was required to be able to adequately illuminate the closed valve disc for ICM-305 and ICM-306. Step 4.2.4 of 12-MHP-4030-031-001 did not appropriately address the use of remote observation equipment to view the piping and the valve discs when the piping was filled with water. When the maintenance inspection was performed on November 15, 2003, it was not possible for the maintenance craftsman to perform an adequate inspection of the suction piping up to the valve discs because both legs of the piping were filled with water and he was not able to view the discs by simply shining a flashlight down the open ends of the piping. The length of piping filled with water was about 20 feet. The inspectors interviewed the maintenance craftsman who stated that he shined his flashlight into the water and saw something shinny, which he believed was the valve discs. After the inspectors identified the inadequacy of the maintenance inspection to the licensee, a boroscopic inspection of the suction piping was performed to satisfy this requirement.

- The maintenance craftsman also noted in Step 4.2.8 that the carbon steel fasteners attaching the lower support ring for the abandoned level standpipes to the floor of the recirculation sump were satisfactory with no damage. This was not the case when the inspectors examined the anchor bolts, nuts, and washers. The inspectors interviewed the maintenance craftsman who stated that he did not know what the bolting material was and did not know that there was supposed to be a galvanized coating on them. The licensee's qualified coatings inspector noted in Step 4.2.12 that the carbon steel coatings in the sump were acceptable. The inspectors noted that 12-MHP-4030-031-001 did not identify which structures or components in the sump were constructed of carbon steel and which were intended to be galvanized to aid the performers with their inspection. The inspectors noted that Design Information Transmittal S-00408-00 stated that the inspection shall include a detailed examination of the bolts located at the base of the abandoned stainless steel level instrumentation wells. The bolts were required to be inspected for evidence of deterioration of their galvanizing coating and for corrosion. The maintenance supervisor subsequently referenced CR 0332061 in Step 4.2.15 (discrepancies found during performance) that was written based on the results of the inspectors' observations. In response to these issues identified by the inspectors, the licensee performed a modification to cut away the lower portion of the abandoned level standpipes and remove the support rings. The anchor bolts were drilled out and a cement patch was applied over each of the holes in the floor. Any loose paint was scraped from the floor and walls. The licensee performed an operability evaluation which concluded that the loose coatings and degraded fasteners would not render the ECCS inoperable.

The inspectors determined that the licensee's failure to adequately implement the surveillance test inspection requirements for the ECCS recirculation sump and lower containment sump was a licensee performance deficiency warranting a significance evaluation. The inspectors also concluded that this finding affected the cross-cutting issue of human performance.

Analysis

The inspectors assessed this finding using the Significance Determination Process (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 Disposition Screening," the inspectors determined that a failure to correct these surveillance test procedure implementation inadequacies could become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to adequately perform surveillance testing could reasonably result in the failure to identify degraded or inoperable safety-related equipment. Because the ECCS recirculation sump was primarily associated with long term decay heat removal following certain design basis accidents, the inspectors concluded that this issue was associated with the Mitigating Systems cornerstone. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and determined that this finding was a licensee performance deficiency of very low safety significance because the finding: (1) was not a design or qualification deficiency; (2) did not represent an actual loss of safety function of a system; (3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; (4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and (5) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The inspectors also concluded that this issue did not result in an actual loss or degradation of the heat removal function of the ECCS because the recirculation sump was not required to be capable of performing a safety-related function immediately following the inadequate surveillance testing conducted on November 16, 2003 and the conditions were corrected prior to Unit 1 entering Mode 4.

Enforcement

Technical Specification 6.8.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Appendix A of Regulatory Guide 1.33, Revision 2, recommends procedures for surveillance tests and inspections for the ECCS. Contrary to the above, on November 15, 2003, the licensee failed to adequately implement the requirements of 12-MHP-4030-031-001, "Inspection of Lower Containment and Recirculation Sumps," Revision 2, a surveillance test procedure written to cover an activity referenced in Appendix A of Regulatory Guide 1.33. Specifically, the licensee failed to adequately perform the following: (1) check the lower containment sump screen wire mesh for rips, tears, openings or gaps that were large enough to allow particulate larger than 1/4 inch to pass through or around screens as required by Step 4.1.4; (2) perform a visual examination of residual heat removal pump suction piping from the sump to the valve discs of ICM-305 and ICM-306 for debris greater than 1/4-inch in diameter as required by Step 4.2.4; (3) check level instrumentation well lateral support bracket mounting nuts for evidence of abnormal deterioration as required by Step 4.2.8; and (4) accurately identify and record the degradation of galvanized coatings on carbon steel fasteners for the level instrumentation well lateral support brackets as required by Step 4.2.12. However, because of the very low safety significance, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000315/2003012-02). The licensee entered this violation into their corrective action program as CR 0332060, CR 03320061, CR 03322049, and CR 03324004.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following two temporary modifications and verified that the installation was consistent with design modification documents and that the modifications did not adversely impact system operability or availability.

- 1-TM-03-80-R0, "Install Temporary Lead Shielding on Unit 1 RHR Heat Exchanger"
- 1-TM-03-80-R0, "Tap Changes for the Unit 1 Auxiliary Transformers 1-TR1AB and 1-TR1CD During the Unit 1 Refueling Outage (U1C19)"

The inspectors verified that configuration control of the modifications were correct by reviewing design modification documents and confirmed that appropriate post-installation testing was accomplished. The inspectors interviewed engineering, radiation protection and operations department personnel and reviewed the design modification documents and 10 CFR 50.59 evaluations against the applicable portions of the TS and Updated Final Safety Analysis Report.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed activities in the plant simulator, Technical Support Center and the Operations Support Center during an emergency preparedness drill conducted on September 30, 2003. The inspectors verified that the emergency classifications and notifications to offsite agencies were completed in an accurate and timely manner as required by the emergency plan implementing procedures. The inspectors also verified that the drill was conducted in accordance with the prescribed sequence of events, drill objectives were satisfied and that the required prompts from the licensee drill controllers were appropriately communicated to the drill participants.

The inspectors observed the post-drill critique in the Technical Support Center and reviewed documented post-drill critique comments by licensee evaluators to verify that licensee personnel and licensee drill evaluators adequately self-identified drill performance problems. The inspectors also verified that CRs were generated for drill performance problems and entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors verified the Safety System Functional Failures Performance Indicator for both units. The inspectors reviewed each Licensee Event Report (LER) from October 2002 to September 2003, determined the number of safety system functional failures that occurred, evaluated each LER against the performance indicator definitions, and verified the number of safety system functional failures reported.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors verified the Reactor Coolant System Leakage Performance Indicator for both units. The inspectors reviewed operating logs and the results of RCS water inventory balance calculations performed from October 2002 through September 2003 and verified the licensee’s calculation of RCS leakage for both units.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As 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 corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Some minor issues entered into the licensee’s corrective action system as a result of inspectors’ observations are included in the list of documents reviewed which are attached to this report.

b. Findings

No findings of significance were identified.

.2 Routine Review of Identification and Resolution of Problems During Inservice Inspection

a. Inspection Scope

The inspector reviewed a sample of inservice inspection related problems that were identified by the licensee and entered into the corrective action program. The inspector reviewed these corrective action program documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspector’s review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The specific corrective action documents that were reviewed by the inspectors are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

.3 Annual Sample Review

a. Inspection Scope

The inspectors selected the following two issues for detailed review:

- Condition Report 03158021, "Examination of the Previously Installed 1E and 2E ESW Pump Bowls Identified Bearing Damage and Adhesion of Bearing Material to the Pump Shaft"
- Condition Report 03016007, "Unit 1 Reactor Trip and Fire in the Main Transformer"

The inspectors verified the following attributes during their review of the licensee’s corrective actions for the above CRs and other related CRs:

- consideration of the extent of condition, generic implications, common cause and previous occurrences;
- classification and prioritization of the resolution of the problem, commensurate with safety significance;
- identification of the root and contributing causes of the problem; and
- identification of corrective actions which were appropriately focused to correct the problem.

The inspectors discussed the corrective actions and associated CR evaluations with licensee personnel.

b. Findings and Observations

No findings of significance were identified. The inspectors had the following observations regarding the licensee's root cause evaluations and corrective actions for the two CRs.

b.1 Degraded Essential Service Water (ESW) Pump Bearings

The inspectors reviewed the events prior to the initiation of CR 03158021 on June 7, 2003, concerning bearing damage and bearing material adhering to the pump shaft of an ESW pump.

The four ESW pumps at the facility are all safety-related. The bearing damage occurred after the pumps were redesigned, to address accelerated impeller wear which the licensee ascribed to increased sand entrainment because of low Lake Michigan water level. A series of pump re-builds by the manufacturer (Johnston Pump) and changes to harder and harder wear rings had not solved the problem. The modification was developed to change the impellers from a closed to a partially open configuration, with hardened impeller edges. During design development, the licensee determined that the wear problems had actually resulted from unbalanced axial forces in service. Further, two shaft support "spiders" incorporated in the original design had never actually been installed. The modification was revised to address the axial wear and shaft support issues. Throughout the design development and implementation, the licensee raised design and verification concerns, including concerns about impeller height, lift settings and clearances. Engineering analyses were requested but not provided, and testing deficiencies at the manufacturer test facility were noted but not resolved. An "at risk" provision of the Quality Assurance program was invoked, so that the licensee could proceed despite the identified deficiencies. Licensee analyses, using assumed input parameters, suggested the manufacturer's design modification, which was being developed empirically, would result in pumps with potential impeller/bowl interference at startup, and marginal performance at rated flow.

As part of the modification, Thordon brand bearings were chosen for use as the line-shaft and pump-shaft bearings. This choice was based on successful performance in other nuclear units, demonstrating wear resistance in abrasive environments. However, Thordon was not on the licensee's approved supplier's list for "Q-grade" parts, which necessitated that a dedication process be used to upgrade the parts after receipt. In addition, the licensee found that it lacked the capability to perform final machining of the inner pump-shaft bearings in place as originally intended, so these bearings were machined to final specifications at the Thordon factory. Bearing installation involved super-cooling them in liquid nitrogen before sliding them onto their respective shaft sections.

When installed in the plant in late 2002, three of the pumps exhibited rubbing sounds on startup. Discharge head was also lower than expected, but met minimum criteria for operability. Thereafter, discharge head performance degraded much more slowly than it had before the design modification. By June 2003, however, performance on one pump had degraded to the "Alert" range and a second was approaching that range. The licensee then removed the Unit 1 East and Unit 2 East ESW pumps from service for rebuilding, discovering the bearing damage reported in the CR. Subsequently, excessive impeller wear was also identified.

The inspectors reviewed the licensee's investigation of the issue, which included a root cause evaluation and held discussions with the lead rotating equipment engineer. The root cause evaluation was performed by a multi-disciplined team of experts and their report was thorough and comprehensive. It identified two root causes and nine contributing causes. The root causes involved failures by both the pump and the bearing manufacturers to perform adequate engineering in support of the design modification, and failure by the licensee to provide project management controls commensurate with the risk and complexity of this design modification. The licensee was faulted for not stopping work in the face of continuing engineering discrepancies. The contributing causes were of a technical nature, involving identification and control of critical characteristics, standards and methods for performance verification, selection of parts, and pump operating practices and conditions. Because of these failures, the re-design proved inadequate on two counts: 1) the inner pump-shaft bearing was asymmetrically compressed and "swelled" at the center as it warmed up so that it interfered with the shaft, overheated, and sustained the observed displacement and damage; and, 2) the coupling settings were determined at a test facility which did not test the full range of flow, resulting in impeller/bowl interference (and rubbing noises) during pump startup, yet leaving excessive clearance (and low output) at rated flow.

The inspectors thoroughly examined the causes and concluded the licensee had not neglected any likely factors. The corresponding corrective actions were reviewed and found to address the causes appropriately. Corrective action for part of one root cause rested on follow-through on a Nonconformance Report by the pump manufacturer, a "Q-grade" supplier. The inspectors also determined that the ability of the pumps to meet minimum performance requirements was never compromised.

b.2 <u>Unit 1 Reactor Trip and Fire in the Main Transformer</u>

On January 15, 2003, a fault occurred in the Unit 1 main transformer resulting in a fire. The fault caused an automatic main generator trip and reactor trip. The licensee returned the unit to full power on February 6, 2003, after replacing the transformer and accomplishing some additional maintenance activities.

The inspectors reviewed the root cause evaluation, post-trip report, and related CRs for the Unit 1 main transformer fire. The root cause was determined to be the result of an insulation failure within the 345 kV winding of phase 1 of the transformer (i.e., insulation breakdown following factory testing that was not detected). No contributing causes were identified. The inspectors thoroughly examined the licensee's root cause evaluation and concluded the licensee had not neglected any likely factors. The corresponding corrective actions were reviewed and found to appropriately address the cause. Having a clear understanding of the root cause was particularly important because the failed transformer had had a relatively short service life and the replacement transformer was from the same manufacturer and was the same model.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 50-315/1998-020-02: "Containment Recirculation Sump pH Upper Limit Exceeded Due to Analysis Input Omission," Supplement 2. On April 8, 1998, with both units in Mode 5 (Cold Shutdown), questions were raised by inspectors performing a safety system functional inspection on the CTS system regarding the method used for determining the containment recirculation sump pH. It was determined that the Westinghouse BORDER computer model used to determine the pH in the containment sump had not included the sodium hydroxide contained in the ice condenser ice bed. The reference made to sodium hydroxide was later determined to be incorrect and the correct reference should have been sodium tetraborate. The failure to include this chemical in the calculation could potentially have resulted in the containment sump pH value exceeding the maximum pH limit of 9.5 following a loss of coolant accident contained in Unit 1 TS Sections 3/4.1.2 and 3/4.5.5. Completion of an additional analysis by Westinghouse utilizing the BORDER computer model including sodium tetraborate indicated that the TS limit of 9.5 would not be exceeded. This was documented in Westinghouse letter AEP-98-070, "Maximum Sump pH - Justification for Past Operation," dated May 15, 1998. Subsequent investigation by licensee personnel including a revision to calculation MD-12-CTS-118-N, "Containment Spray System and Recirculation Sump Minimum and Maximum pH," Revision 4, resulted in a revision to D. C. Cook Unit 1 TS, Sections 3/4.1.2 and 3/4.5.5. The licensee submitted Supplement 2 to LER 50-315/1998-020 to provide the results of the additional Westinghouse analysis and to retract the original LER. The inspectors concluded that the licensee's actions to resolve this issue were adequate and no findings of significance were identified. This LER is closed.

.2 (Closed) 50-315/2003-001-00: "Unit 1 Turbine Trip and Reactor Trip Due to Main Transformer Fault and Fire." The event described in this LER was also discussed in Section 4OA2.3.b.2 of this report. The cause of the event was a sudden internal fault in the transformer that resulted in a phase-to-phase flashover. The transformer oil tank ruptured resulting in a loss of oil and a fire. The inspectors concluded that this event did not constitute a violation of NRC requirements. The licensee reported this event as a condition that resulted in an automatic actuation of the reactor protection system in accordance with 10 CFR 50.73(a)(2)(iv)(A). This LER is closed.

.3 Response to Unit 2 Seal Water Injection Filter Housing Leak

a. Inspection Scope

On December 19, 2003, the licensee activated the Emergency Plan at the Unusual Event level due to a leak of approximately 30 gallons-per-minute from the Unit 2 North seal water injection filter. Operators placed the South seal water injection filter in service and isolated the North seal water injection filter. The licensee subsequently terminated the Unusual Event. Unit 2 remained stable at full power during the event.

The inspectors assessed the licensee's emergency response organization and control room operator performance during the event. The inspectors evaluated the plant conditions and the licensee's actions to mitigate the affect on plant systems and recover from the event. The inspectors also confirmed that the licensee made timely notifications to the NRC, State of Michigan, and local officials.

b. Findings

No findings of significance were identified.

.4 Unit 2 Reactor Trip Response

a. Inspection Scope

On December 30, 2003, Unit 2 experienced an automatic reactor trip due to the unplanned closure of the Number 22 and 23 steam generator feedwater isolation valves. The feedwater isolation valve closure originated from an abnormality in the CRID 120 Volt AC power system. Technicians were landing leads on an RHR system flow transmitter which was powered from the suspected CRID power supply at the time of the event. An arc was observed during the lead landing procedure. The licensee restarted and synchronized Unit 2 to the grid on January 4, 2004, after verifying that no damage was caused as a result of the electrical short. The inspectors assessed Control Room operator performance immediately following the reactor trip and reviewed the post trip report.

b. Findings

No findings of significance were identified.

4OA4 Cross-Cutting Aspects of Findings

Section 1R22 of this report describes a finding in which licensee personnel failed to adequately implement the surveillance test inspection requirements for the Unit 1 ECCS recirculation sump and lower containment sump. The inspectors concluded that this finding affected the cross-cutting area of Human Performance.

4OA5 Other Activities

.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On August 9, 2002, the NRC issued Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs." The purpose of this Bulletin was to: (1) advise pressurized water reactor (PWR) licensees that visual examinations, as a primary inspection method for reactor pressure vessel head and vessel head penetration (VHP) nozzles, may need to be supplemented with additional measures; (2) advise PWR licensees that inspection methods and frequencies to demonstrate compliance with applicable regulations should be demonstrated as effective and reliable; (3) request information from all PWR addressees concerning the Reactor Pressure Vessel (RPV) head and VHP nozzle inspection programs; and (4) require all PWR addressees to provide written responses to this bulletin related to their inspection program plans.

On February 11, 2003, the NRC issued Order EA-03-009 (NRC ADAMS Accession Number ML030410402). The purpose of this order was to require specific inspections of the RPV head and associated penetration nozzles, as discussed in Bulletin 2002-02. The purpose of TI 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," Revision 2, was to implement an NRC review of the licensees' RPV head and VHP nozzle inspection activities required by NRC Order EA-03-009. The inspector performed a review in accordance with TI 2515/150 of the licensee's procedures, equipment, and personnel used for RPV VHP examinations to confirm that the licensee met the requirements of NRC Order EA-03-009. The results of the inspector's review included documentation of observations and conclusions in response to the questions identified in TI 2515/150.

The inspector performed a review of the licensee's head inspection related activities in response to NRC Order EA-03-009. To evaluate the licensee's efforts in conducting examination and repair of the reactor vessel head and penetration nozzles, the inspector:

- performed direct visual examination of the head-to-nozzle interface for portions of 20 VHP nozzles inside the Unit 1 containment;
- observed the licensee personnel conducting a remote visual examination of the RPV head for portions of 40 VHP nozzles;
- conducted interviews with the licensee's nondestructive examination personnel performing non-destructive examinations of the RPV head;
- reviewed the head inspection procedures;
- reviewed the certification records for the nondestructive examination personnel performing examinations of the RPV head;
- reviewed the procedures used for identification and resolution of boric acid leakage from systems and components above the RPV head; and
- reviewed the licensee's procedures and corrective actions implemented for boric acid leakage identified on components above the RPV head.

The inspector conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009 using procedures, equipment, and personnel effective in the detection and sizing of primary water stress corrosion cracking (PWSCC) in VHP nozzles and detection of RPV head wastage.

The inspector reviewed the licensee's VHP nozzle susceptibility ranking calculation EVAL -SD-030924, "Cook Nuclear Plant Unit 1 - Calculation of Effective Degradation Years (EDY) of Operation for Unit 1," to:

- verify that appropriate plant-specific information was used as an input;
- confirm the basis for the head temperature used by the licensee; and
- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

The inspector conducted these reviews to confirm that the licensee performed the VHP nozzle susceptibility calculation using best estimate values for input parameters in accordance with the requirements of NRC Order EA-03-009.

b. Observations

Summary

The licensee performed a remote visual examination using a robotic crawler with a high-resolution camera as well as a video probe delivered through a guide tube to complete examination of the 80 Unit 1 VHP nozzles (includes head vent location) on the vessel upper head. Based upon this inspection the licensee identified no leaking VHP nozzles and no evidence of vessel head wastage.

Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/150, the inspector evaluated and answered the following questions:

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee conducted a remote visual examination of the top surface of the RPV head with knowledgeable staff members certified to Level II as VT-2 examiners in accordance with Procedure PDP-7040-001, "Qualification and Certification of Inspection, Test, Examination, and NDE Personnel." This procedure was consistent with the requirements and recommendations of the American Society for Nondestructive Testing Recommended Practice SNT-TC-1A. Additionally, VT-2 personnel had access to photographs of each penetration location taken during the last Unit 1 visual head inspection in 2002.

2. For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?

   No. The licensee performed the RPV head inspection in accordance with Procedure 54-ISI-367-05, "Procedure for the Visual Examination for Leakage of Reactor Head Penetrations." The licensee did not consider this procedure to be a demonstrated procedure, although it did contain a requirement to confirm color resolution and to resolve lower case alpha-numeric characters. Specifically, the procedure required the camera system to be able to resolve 0.044 inch high alpha numeric characters within 12 inches of the camera with 50 foot-candles of illumination. However, the inspector identified parameters that could impact the quality and/or effectiveness of the inspection and were not controlled by the procedure. Specifically, the procedure did not require:

- demonstration of the near distance camera resolution capability;
- confirming resolution capability after adjusting the inspection camera's focal length (remotely controlled); or
- using qualified or certified visual examination personnel.

For each item discussed above, the licensee provided verbal direction to control the parameters, such that the quality of the visual examination was not compromised.

The inspector observed the licensee personnel performing the remote visual examination of the upper surface of the reactor head under the insulation using a camera mounted to a robotic crawler in accordance with Procedure 54-ISI-367 05 for portions of 40 VHP nozzle locations. The licensee was able to position the inspection camera within a few inches of the VHP interface with sufficient lighting such that an excellent visual image was obtained.

The inspector reviewed the licensee's demonstration of color acuity and visual resolution and noted that it was consistent with the procedure requirements. The inspector also performed a direct visual inspection for portions of 20 VHP nozzles viewable at the 200 degree and 320 degree head azimuth locations through removed insulation and access doors at these locations. Based on this examination, the inspector noted that the remote picture quality appeared to provide for a superior inspection to that achievable by direct visual examination at the service structure access doors. Overall, the inspector considered that the quality of the remote visual examination was excellent based on the ability to resolve very small debris at the VHP nozzle-to-head interfaces.

3. For each of the examination methods used during the outage, was the examination able to identify, disposition, and resolve deficiencies and capable of identifying the PWSCC and/or head corrosion phenomena described in Order EA-03-009?

   Yes. The upper head had been cleaned during the previous outage and was relatively free of debris or deposits which would mask evidence of leakage. The inspector considered the remote visual examination resolution and picture quality equal or superior to a direct visual examination. Further, the licensee was able to obtain a complete visual examination at each VHP interface area and adjacent vessel head surfaces. Therefore, the inspector concluded that the inspection performed was capable of detecting evidence of leakage at VHPs cause by PWSCC or corrosion of the vessel head caused by boric acid.

4. What was the physical condition of the reactor head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

   The head was covered with a light gray colored aluminum based coating applied by the head fabricator, which provided an adequate surface for visual resolution of boric acid deposits. The reactor head insulation consisted of reflective metal insulation panels installed on a support structure over the top of the reactor head. The remote camera visual inspection was conducted under the insulation support structure and the as-found head condition was generally clean (free of debris, insulation, dirt). The uphill side of the annulus gap on a few penetrations contained loose debris, which generally did not hinder the licensee's evaluation of the penetration. Additionally, the licensee's robotic crawler had a pressurized air source which was used to blow loose debris out of the nozzle-to-head interface. The center penetration, head vent location and quadrants of penetrations near insulation support structures at the head periphery were obstructed from the crawler mounted camera and the licensee used a fiber optic scope to view these areas. The licensee did not identify any limitations to a complete visual examination (e.g., 360 degrees) of the VHP nozzle-to-head interface for each of the 80 head penetrations.

The licensee performed a systematic inspection and documented the visual examination results in each of four quadrants for every VHP nozzle-to-vessel interface. No indications of head leakage were recorded. The inspector independently observed the remote visual examination for portions of 40 VHPs and did not observe any white deposits (boric acid) with characteristics (popcorn like) indicative of RCS leakage.

5. Could small boron deposits, as described in Bulletin 2001-01, be identified and characterized?

   Yes. Based upon the quality and scope of the licensee's visual examination, the inspector concluded that any boron deposits characteristic of coolant leakage would have been identified (if any had been present).

6. What material deficiencies (i.e., cracks, corrosion, etc) were identified that require repair?

   None.

7. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation thermal sleeves, instrumentation, nozzle distortion)?

   None. The licensee's video camera mounted on a robotic remote crawler was able to obtain access to 360 degrees around most of the vessel head penetration locations. At the center VHP location, the head vent and portions of periphery VHP locations, the licensee used a camera and fiber optic scope to perform supplemental examinations for the areas of these VHPs not viewable by the camera mounted on the robotic crawler. For example, at the periphery VHP locations (e.g., penetrations 74, 75, 77, 78, and 79), the licensee had to lift vertical insulation panels and use a camera attached to a fiberscope inserted from under the panel to complete these examinations.

8. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations, (e.g., thermal hydraulic modeling), etc.?

NRC Order EA-03-009 required licensees to calculate the susceptibility category of each reactor head to PWSCC-related degradation. The susceptibility category in EDY establishes the basis for the licensee to perform appropriate head inspections during each refueling outage. The licensee documented the Unit 1 RPV head EDY in calculation EVAL-SD-030924, "Cook Nuclear Plant, Unit 1 - Calculation of Effective Degradation Years (EDY) of Operation for Unit 1." In this calculation, the licensee used the formula required by NRC Order EA-03-009 and determined the EDY for each operating cycle. At the conclusion of Cycle 18 on October 20, 2003, the licensee determined that the Unit 1 RPV head was at 8.1 EDY. This value placed the Unit 1 RPV head in the low end of the moderate susceptibility category. The inspector also reviewed the examination records from the previous Unit 1 head examinations and confirmed that no PWSCC of VHPs had been identified.

NRC Order EA-03-009 also required the licensee to have used best estimate values in determining the susceptibility category for the vessel head. The inspector reviewed Design Information Transmittal S-00705 which documented the effective full power operating years and Westinghouse letter report LTR-RCDA-0377, which documented the head operating temperature for each cycle. Based on this review, the inspector concluded that the licensee had used applicable plant specific information (e.g., best estimate values) in determining the EDY value in calculation EVAL-SD-030924.

9. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?

   The inspector determined that this question was not applicable, because the licensee performed only visual examinations and no flaws were identified.

10. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the RPV head?

    Yes. The licensee performed inspections of components within containment to identify leakage which included the area above the RPV head. This inspection was conducted by Operations and Maintenance Department personnel with the plant in a hot shutdown condition in accordance with Procedures 02-0HP-4030-001-002, "Containment Inspection Tours," and PMP-5030-001-001, "Boric Acid Corrosion of Ferritic Steel Components and Material." The licensee also performed inspections to identify boric acid leakage (including areas above the RPV head) during performance of Code pressure test 12-QHP-5070-NDE-002, "Visual VT-2 Examinations Inservice and Repair/Replacements." These procedures provided for the detection and disposition of boric acid on components. In general, boric acid deposits were placed into two categories: "Active Wet Leakage" and "Inactive/Minor Dry Residue." The first category required evaluation and the second category generally required only cleaning or was accepted as is. Procedure 12-QHP-5070-NDE-002 provided further guidance for boric acid deposits on insulation.

Specifically, this procedure stated, "IF, evidence of leakage is observed, THEN remove the insulation to determine the source of leak."

11. Did the licensee perform appropriate follow-on examinations for boric acid leaks from pressure retaining components above the RPV head?

    Yes. The licensee could not provide records of boric acid leakage from components above the head prior to 1992, because these records were not readily retrievable. The licensee provided Job Order No. C0017393, which documented the results of a 1994 visual inspection of the reactor vessel head. In this examination, the licensee identified boric acid deposits which had run down from pressure retaining components at 4 VHPs. During a subsequent licensee review of this videotaped inspection, an additional 4 VHPs were identified with boric acid deposits. During a May 16, 2002, visual examination of VHPs the licensee documented the results of the Unit 1 vessel head inspection. During this inspection the licensee identified boric acid deposits on 4 VHPs and adjacent vessel head surfaces. The licensee attributed these deposits to leakage from canopy seal welds or leakage at conoseal connections above the VHPs. The licensee cleaned and reinspected the head at the areas with boric acid deposits as documented in CR 02136042. No evidence of wastage was observed on the vessel head.

c. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/152, Reactor Pressure Vessel (RPV) Lower Head Penetration Nozzles (NRC Bulletin 2003-02)

a. Inspection Scope

On August 21, 2003, the NRC issued Bulletin 2003-02, "Leakage from RPV Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity." The purpose of this Bulletin was to: (1) advise PWR licensees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary leakage; (2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and; (3) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the Code of Federal Regulations (10 CFR 50.54(f)).

The objective of TI 2515/152, "Reactor Pressure Vessel Lower Head Penetration Nozzles," was to support the NRC review of licensees' RPV lower head penetration inspection activities that were implemented in response to the NRC Bulletin 2003-02. The licensee had committed to perform a bare metal inspection of the lower vessel head for Unit 1 in response to the NRC Bulletin 2003-02. The inspector performed a review in accordance with TI 2515/152, Revision 0, of the licensee's procedures, equipment, and personnel used for RPV lower head penetration examinations to confirm that the licensee met commitments associated with NRC Bulletin 2003-02. The results of the inspector's review included documenting observations and conclusions in response to the questions identified in TI 2515/152.

The inspector performed a review of the licensee's activities associated with inspecting the Unit 1 lower vessel head. Specifically, the inspector:

- performed a direct visual examination of the nozzle-to-head interface for portions of 20 of the 58 bottom head penetrations inside the Unit 1 containment from a staging platform under the reactor vessel;
- interviewed nondestructive examination personnel;
- reviewed lower head visual Inspection Procedure 12-QHP-5050-NDE-027;
- reviewed the certification records for the nondestructive examination personnel;
- reviewed the licensee's procedure for certification of visual examination personnel;
- observed the licensee inspection personnel conducting the remote visual examination for portions of 30 nozzles on the RPV lower head from the head inspection trailer within the site protected area; and
- reviewed visual examination and evaluation of indication records.

b. Observations

Summary

Based upon a bare metal remote visual examination of the lower head, the licensee did not identify evidence of RCS leakage near the instrument nozzle penetrations. One quadrant of the vessel at the 270 degrees azimuth had evidence of corrosion and boric acid residues that were caused by rundown from liquid sources above the bottom of the vessel (e.g., refueling cavity seal leakage). Several penetrations in this quadrant were affected by this rundown such that the licensee identified six nozzles with debris/deposits at the nozzle-to-head interface. For these nozzles, the licensee initially considered the visual examination results to be indeterminate pending chemical testing of these deposits. Based upon isotopic and chemical analysis of residues collected near the "indeterminate" penetrations, the licensee determined that these deposits were caused by refueling water sources leaking through the cavity seals.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/152, the inspector evaluated and answered the following questions:

For each of the examinations methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee conducted a remote visual examination of the Unit 1 RPV lower head penetration interface and RPV lower head surface for leakage or boric acid deposits with knowledgeable staff members certified to Level II as

VT-2 examiners in accordance with Procedure PDP-7040-001, "Qualification and Certification of Inspection, Test, Examination, and NDE Personnel." This procedure was consistent with the requirements and recommendations of the American Society for Nondestructive Testing Recommended Practice, SNT-TC-1A. Additionally, VT-2 inspection personnel had access to photographs of the boric acid deposits indicative of leakage found at the South Texas Nuclear Power Plant.

2. Performed in accordance with demonstrated procedures?

No. The licensee performed a bare metal inspection of the lower head in accordance with Procedure 12-QHP-5050-NDE-027, "Visual Examination For Boric Acid And Condition of Component Surfaces." The licensee did not consider this procedure to be a demonstrated procedure although it did contain requirements to verify color and to resolve lower case alpha-numeric characters. Specifically, the procedure required the camera system to be able to resolve Code VT-1 and VT-2 sized alpha numeric characters within 12 inches of the camera. However, the inspector identified parameters that could impact the quality/effectiveness of the inspection, which were not controlled by the procedure. Specifically, the procedure did not require:

- verification of the resolution capability of the battery operated camera system at periodic intervals as the battery was expended;
- confirmation of the resolution capability after manually adjusting the inspection camera's focal length. Nor did the procedure require a check of the near distance resolution capability (e.g., the point at which the image begins to get fuzzy as the camera approached the object under examination); or
- samples of deposits identified near the interface of lower head penetrations. Specifically, no guidance for when samples would be taken, how samples would be collected and what analysis would be performed to determine the source of deposits identified.

For each item discussed above, the licensee provided verbal direction to control the parameters, such that the quality of the visual examination was not compromised. The licensee documented these procedure weaknesses in CR 03297036.

The inspector observed the licensee personnel performing the remote visual examination of the bare metal surface of the lower reactor head under the insulation using a camera mounted to a pole in accordance with Procedure 12-QHP-5050-NDE-027 for portions of 30 penetration locations. The licensee was able to position the camera within a few inches of the head-to-nozzle interface at each penetration with sufficient lighting such that an excellent visual image was obtained.

The inspector reviewed the licensee's demonstration of color acuity and visual resolution and noted that it was consistent with the procedure requirements. The inspector also performed a direct visual inspection for portions of 20 head penetration nozzles viewable from the staging installed under the vessel in the reactor pit. Based on this examination, the inspector concluded that the quality of the remote visual camera system provided for a superior inspection as compared to a direct visual examination conducted from the staging area in the reactor pit. Overall, the inspector considered that the quality of the remote visual examination was excellent based on the ability to resolve very small debris at the lower VHP nozzle-to-head interfaces.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The lower vessel at the 270 degree quadrant contained corrosion and stains in a pattern that suggested a flow of liquid had run down from a source above the lower head. This flow pattern impacted several lower head penetrations. In most cases this flow pattern did not cover the VHP interface because of a raised metal pad that extended for several inches around the surface of the lower vessel head at each penetration. Based upon the visual examination, the licensee did not identify any penetrations with deposits which were considered indicative of leakage. However, the licensee identified 6 of the 58 penetrations with debris/deposits near the interface and considered these locations as indeterminate.

   For the six indeterminate lower VHPs, the licensee collected samples of deposits at the interface area and performed a chemical analysis to determine the origin of the material. Based upon this sampling, the licensee determined that the source of the material at these penetrations was attributed to deposits left by refueling water which had run down the side of the vessel due to cavity seal leakage.

4. Capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

   Yes. The inspector performed a direct visual inspection of portions of 20 lower VHPs. Based on this examination, the inspector noted that the remote picture quality appeared to provide superior inspection to that available by direct visual examination. Therefore, the inspector concluded that the remote visual examination was capable of detecting deposits indicative of pressure boundary leakage as described in the bulletin.

5. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, boric acid deposits from other sources, physical layout, viewing obstructions)?

   The inspector observed scattered patches of what the licensee staff believed was an aluminum based coating applied to the RPV by the head fabricator prior to installation. The remnants of this coating did not interfere with the inspection. The lower vessel at the 270 degree quadrant contained corrosion and stains in a pattern that suggested a flow of liquid had run down from a source above the lower head. The licensee concluded that this flow pattern was the result of cavity seal leakage based upon chemical testing. The licensee documented in CR 03135023 a chronic history of cavity seal leakage in both Units. Prior to replacing the seals in 1995, the licensee reported, using temporary sealant material to reduce the leakage. In 1995, the Unit 1 and 2 seals were changed from a Pressray cavity seal (air bladder) to a Preferred Engineering seal which used mechanical seals over the annulus created by the cavity floor and vessel. The new seals reduced but did not eliminate cavity seal leakage and the licensee reported that the Unit 2 cavity seals were still leaking at 2 - 4 gallons per minute. The licensee did not believe that the Unit 1 seals were leaking and intended to check for Unit 1 cavity seal leakage following refueling activities.

6. Could small boric acid deposits, as described in the Bulletin 2003-02, be identified and characterized?

   Yes. If small boric acid deposits characteristic or indicative of leakage had existed, the licensee's examination would have identified these. However, no boric acid deposits indicative of leakage were identified.

7. What material deficiencies (i.e., crack, corrosion, etc.) were identified that required repair?

   None. No boric acid deposits indicative of leakage were identified and thus no repairs were required. Additionally, the corrosion and stains identified at the 270 degree quadrant were not considered significant and thus did not require repair. Following completion of the examination, the licensee intended to clean the lower head and reinstall the reflective metal insulation that had been removed.

8. What, if any, impediments to effective examinations, for each of the applied nondestructive examination method, were identified (e.g., insulation, instrumentation, nozzle distortion)?

   The remote video camera visual examination required access to the RPV lower head and instrument nozzle penetrations by climbing down a ladder, into the reactor pit (a sump area under the vessel). This area was a confined space, a high radiation area, and was congested by the instrument tubes and their supports. Scaffold was installed to remove and lower the reflective metal insulation and to position the video camera near the penetrations. A minimum of about 2 feet of clearance existed between the lower head and the removed metal insulation. This gap provided the licensee personnel sufficient clearance to conduct the inspection using a camera mounted on a pole.

9. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

Yes. The licensee collected samples of residue from each of the six indeterminate penetration locations, the rundown area and two locations on the reactor pit walls (note samples at penetrations 12, 23 and 47 were combined to achieve enough sample material - 5 milligrams). The licensee analyzed these deposits in accordance with GLG.911, "Chemistry Lab Guide for Deposits Sample and Analysis." Each sample was analyzed for lithium, calcium, iron, magnesium, sodium, zinc, chrome, copper, manganese, and nickel. The licensee used an inductive coupled plasma mass spectrometer for the elemental analysis. Due to the very small sample sizes, boron could not be directly quantitatively analyzed (e.g., amount present was estimated by comparing the signal strength from the mass spectrometer with signal strength from a known quantity). No detectible lithium was identified at three of the six penetrations and the sample of the boric acid stain around penetrations 12, 23, and 47 contained only trace amounts (5 parts per billion (ppb), minimum detectable of 2 ppb) of lithium. Based upon the low lithium levels, and the fact that the lithium to boron ratio was estimated to be 1 to 100 instead of the 1 to 4 ratio observed at South Texas, the licensee concluded that the deposits were not indicative of RCS leakage. The licensee believed that prior to 1997, leakage past the cavity seals may have contained lithium due to over extended operation of the boric acid evaporator feed demineralizers. The licensee also confirmed that the percentage of the boron-10 isotope in the samples on the lower head were consistent with that found in refueling borated water sources, vice that found in the reactor coolant. The licensee determined the age of the deposits by isotopic analysis and evaluation of the ratios of Cs-137 to Cs-134 or Co-58 to Co-60. For the combined sample collected from penetrations 12, 23, and 47, the licensee determined that the sample was 10.9 years old and contained trace amounts of lithium. For the samples taken at penetrations 22, 51, and the east wall, the licensee determined that the samples were about 1 year old, and did not contain detectable amounts of lithium. For penetration 38 and the west wall sample, the licensee could not determine an age, due to the lack of shorter lived isotopes (Cs-134 or Co-58) and these samples did not contain lithium.

Overall, the analytical results of the lower vessel head deposits supported the licensee’s conclusion that the deposits did not originate from the RCS during the last operating cycle. The licensee planned to clean these old deposits from the lower vessel head and take pictures of the clean condition to use as a baseline for future visual inspections. The licensee also planned to re-inspect the lower head area after refueling for new evidence of cavity seal leakage.

c. Findings

No findings of significance were identified.

4OA6 Meetings

.1 Resident Inspectors’ Exit Meeting

The inspectors presented the inspection results to Mr. M. Nazar and other members of licensee management at the conclusion of the inspection on January 8, 2004. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Proprietary information was examined during this inspection, but is not specifically discussed in this report.

.2 Interim Exit Meetings

The results of the Inservice and Temporary Instruction 2515/150 Inspection were presented to Mr. M. Nazar and other members of licensee management at the conclusion of the inspection on October 30, 2003 and November 6, 2003. The licensee acknowledged the findings presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

P. Cowan, System Engineering Manager
M. Finissi, Plant Manager
J. Giessner, Plant Engineering Director
R. Hall, Inservice Inspection Program
J. Jensen, Site Vice President
E. Larson, Maintenance Director
B. Mann, Regulatory Affairs Manager
M. Nazar, Senior Vice President
S. Simpson, Operations Director
C. Vanderniet, Reactor Vessel Head Project Manager
D. Wood, Radiation Protection/Environmental Manager
J. Zowlinski, Design Engineering & Regulatory Affairs Director

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000315/316/2003012-01	NCV	Non-Code Calibration Block Used For Weld Examination (Section 1R08)
05000315/2003012-02	NCV	Failure to Implement Unit 1 Sump Surveillance Procedure (Section 1R22)

Closed

05000315/316/2003012-01	NCV	Non-Code Calibration Block Used For Weld Examination (Section 1R08)
05000315/2003012-02	NCV	Failure to Implement Unit 1 Sump Surveillance Procedure (Section 1R22)
50-315/1998-020-02	LER	Recirculation Sump pH Limit Exceeded (Section 4OA3.1)
50-315/2003-001-00	LER	Unit 1 Trip Due to Transformer Fault (Section 4OA3.2)

Discussed

50-315/1998-020-00	LER	Recirculation Sump pH Limit Exceeded (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection. Inclusion on this list does not imply the NRC inspectors 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 in 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

- PMI-5055, "Winterization/Summerization," Revision 1
- PMP-5055-001-001, "Winterization/Summerization," Revision 0
- 01-OHP-4021-057-002, "Placing In / Removing From Service Circulating Water Deicing System," Revision 8a
- 12-IHP-5040-EMP-004, "Plant Winterization and De-Winterization," Revision 4a
- 12-OHL-4030-SOM-022, "Unit 12 STP's (Surveillance Test Procedures) - Inside Heat Trace," Revision 1
- 12-OHL-4030-SOM-016, "Unit 12 STP's - Outside Heat Trace," Revision 1
- 12-OHP-5030-001-001, "Operations Plant Tours," Revision 0
- Job Order 0305923, "Calibrate/Repair Heat Trace Circuit"
- Job Order 01073004, "Invest/Repair Heat Trace Circuit No.141"
- Job Order 01296038, "Found Holes in Wall on Unit 1 RWST (Refueling Water Storage Tank) and PWST (Primary Water Storage Tank) / CST (Condensate Storage Tank) Dog Houses"
- D. C. Cook Updated Final Safety Analysis Report (UFSAR), Chapter 9, "Electric Heat Tracing," Revision 18
- Condition Report (CR) 03062002, "Revise Attachments 8 and 9 of 12-OHP-5040-EMP-004 to Ensure Heating Coils for Ventilation Units Drawing Outside Are Prepared for Freezing Temperatures," March 3, 2003
- CR 01150029, "PWST Heat Trace Alarm Continues to Alarm During Cold Weather," April 25, 2001
- CR 01354008, "Heat Trace Circuit 275 for U-1 RWST Has No Alarmostat for Local Temperature Indication, Preventing Temperature Determination for the U-1 RWST Vent Piping," December 20, 2001
- CR 03127040, "1-15A266-HTR-1, RWST Heat Trace Circuit 15A266 Heat Tape No.1 Is Indicating Zero Degrees," May 7, 2003
- CR 03041008, "Numerous Fire Water Storage Tank Heat Trace Alarms this Winter with Nothing Wrong with the Actual Alarms or Heat Trace," February 10, 2003

1R04 Equipment Alignment

- 02-OHP-4021-016-003, "Operation of the Component Cooling Water System During Startup and Power Operation," Revision 14b
- 02-OHP-4021-016-001, Lineup Sheet 1, "Filling and Venting the Component Cooling Water System (East CCW Pump Lineup)," Revision 11
- 02-OHP-4021-016-001, Lineup Sheet 3, "Filling and Venting the Component Cooling Water System (East CCW Heat Exchanger Lineup)," Revision 11
- OP-2-5135-37, "Flow Diagram CCW Pumps and CCW Heat Exchangers," Revision 37

- OP-2-5135A-37, "Flow Diagram CCW Safety Related Loads," Revision 37
- SD-01600, "Component Cooling Water System," Revision 1
- SOD-01600-001, "Component Cooling Water System," Revision 2
- Drawing OP-1-5113-82, "Flow Diagram Essential Service Water," Revision 82
- Drawing OP-1-5113A-6, "Flow Diagram Essential Service Water," Revision 6
- 12-OHP-4021-019-001, "Operation of the Essential Service Water System," Revision 27
- 01-OHP-4030-119-022E, "Unit 1 East ESW Header Flow Path Verification," Revision 2a
- PMP-2291-OLR-001 Data Sheet 1, "Work Schedule Review and Approval Form," Revision 5, Work Week: Cycle-47, W-8
- SD-01800, "Spent Fuel Pit Cooling and Cleanup System," Revision 1
- 12-OHP-4022-018-001, "Loss of Spent Fuel Pit Cooling," Revision 6
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 1: Spent Fuel Pit Water Level High," Revision 4
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 2: Spent Fuel Pit Water Level Low," Revision 4
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 3: Spent Fuel Pit Water Temperature High," Revision 4
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 6: North Spent Fuel Pit Pump Failure," Revision 4
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 7: South Spent Fuel Pit Pump Failure," Revision 4
- 12-OHP-4024-134, "Annunciator No.134 Response Drop 8: Refueling Water Purification Pump Failure," Revision 4
- 01-OHP-4024-138, "Annunciator No.138 Response Drop 5: R5 Spent Fuel Pit Area," Revision 7
- 01-OHP-4024-205, "Annunciator No.105 Response Drop 26: Spent Fuel Pit Sub-panel Alarm," Revision 8
- 01-OHP-4024-205, "Annunciator No.105 Response Drop 27: Spent Fuel Pit Level Low Low," Revision 8
- 01-OHP-4024-205, "Annunciator No.105 Response Drop 28: Spent Fuel Pit Temp High," Revision 8
- 02-OHP-4024-205, "Annunciator No.205 Response Drop 26: Spent Fuel Pit Sub-panel Alarm," Revision 6
- 02-OHP-4024-205, "Annunciator No.205 Response Drop 27: Spent Fuel Pit Level Low Low," Revision 6
- 02-OHP-4024-205, "Annunciator No.205 Response Drop 28: Spent Fuel Pit Temp High," Revision 6
- CR 03306037, "During the Performance of Routine Instrument Source Checks, it Was Discovered That the SRM-100 on the Spent Fuel Pit Bridge Had Not Been Source Checked in Two Days and the Fuel Handlers Were in the Process of Moving Fuel Inserts," November 2, 2003

1R05 Fire Protection

- D. C. Cook Fire Hazards Analysis, Units 1 and 2, Revision 10
- D. C. Cook UFSAR, Section 9.8.1, "Fire Protection System," Revision 18
- D. C. Cook Units 1 and 2 Probabilistic Risk Assessment, Fire Analysis Notebook, February 1995
- D. C. Cook Administrative Technical Requirements Manual, Revision 32

- PMP-2270-CCM-001, "Control of Combustibles," Revision 1
- PMP-5020-RTM-001, "Restraint of Transient Material," Revision 1
- PMP-2270-WBG-001, "Welding, Burning and Grinding Activities," Revision 0b
- PMI-2270, "Fire Protection," Revision 26
- 12-PPP-2270-066-001, "Portable Fire Extinguisher Inspections," Revision 0b
- 12-PPP-2270-066-016, "Appendix A Fire Damper Inspection," Revision 0
- 12-PPP-4030-066-021, "Inspection of Fire Dampers Protecting Safety-Related Areas," Revision 1c
- 12-PPP-4030-066-021, Data Sheet 1, "Inspection of Fire Dampers Protecting Safety-Related Areas (Safety-Related Fire Damper Inspection Sheet)," Revision 1
- 12-QHP-4030-STP-009, Attachment 1, "Inspection of Fire Dampers Protecting Safety-Related Areas," Revision 0
- Drawing No. 12-5973, Fire Hazards Analysis Basement Plan, El. 591'-0" and 587'-0," Revision 9
- Drawing No. 12-5267, Fire Hazards Analysis Basement Plan, El. 591'-0" and 587'-0," Revision 10
- Drawing No. 12-5974, Fire Hazards Analysis Mezzanine Floor, El. 609'-0" Units 1 and 2, Revision 8
- Drawing No. 12-5976, Fire Hazards Analysis Turbine Building Main Floor, El. 633'-0," Units 1 and 2, Revision 8

1R06 Flood Protection Measures

- CR 03231035, "The Requirement of Commitment No. 399 Are Potentially Not Being Satisfied," August 19, 2003
- CR 03234073, "CR 99-16669 Closed Without All Required Actions Taken," August 22, 2003
- CR 03234067, "CR 99-12376 Appears to Have Been Closed Without Adequate Justification," August 22, 2003
- CR 03234074, "CR 99-29555 Is a Back-log CAT X CR That Should Potentially Be Considered a Condition Adverse to Quality," August 22, 2003
- CR 03234071, "CR 99-13655 Closed Without Adequate Justification," August 22, 2003
- CR 03234058, "CR 99-08207 Closure Lacks Proper Justification," August 22, 2003
- Work Request 02309012, "Turbine Room Sump," November 7, 2002

1R08 Inservice Inspection Activities

Documents Associated with Two Types of Nondestructive Testing

- UT Examination Records for the Unit 1 Vessel-to-Flange Weld Completed on April 19, 1989 and November 9, 1995
- UT Examination Records for the Unit 2 Vessel-to-Flange Weld Completed on June 12, 1988, and April 20, 1996
- Procedure 54-ISI-187-10; Ultrasonic Examination of Reactor Vessel Flange to Shell Welds From Flange Top Surface; October 8, 2002
- Eddy Current Examination Data Reports for the Unit 1 Steam Generator No. 14 Tubes
- Job Order No. R0212106, "Documenting Visual Examination Records (VT-2) for Unit 1"
- Pressurized and Depressurized Inspections of Class 1 Components Completed in May and June of 2002 (reference)

- VT-1 Examination Report, "RCP 1-PP-45-2, Bolts1-6,9,10, 12-24," October 29, 2003
- VT-1 Examination Report "RCP 1-PP-45-2, Bolts 16 and 22," November 2, 2003
- VT-1 Examination Report "RCP 1-PP-45-2, Bolt 15," November 3, 2003
- Boric Acid Evaluation R0212106-02-01,1-RC-106-L3, May 13, 2002
- Boric Acid Evaluation R0212106-02-02, 1-PP-45-4, May 13, 2002
- Boric Acid Evaluation R0212106-02-03, 1-PP-45-2, May 13, 2002
- Boric Acid Evaluation R0212106-02-04,1-SI-161-L4, May 13, 2002
- Boric Acid Evaluation R0212106-02-05, 1-NFA-220-OR, May 17, 2002
- Boric Acid Evaluation R0212106-02-06, 1-RC-108-L2, May 17, 2002
- Boric Acid Evaluation R0212106-02-07, 1-SI-158-L1, May 18, 2002
- Boric Acid Evaluation R0212106-02-08, 1-SI-158-L4, May 18, 2002
- Boric Acid Evaluation R0212106-02-09, 1-SI-158-L2, May 18, 2002
- Boric Acid Evaluation R0212106-02-10, 1-SI-158-L3, May 18, 2002
- Boric Acid Evaluation R0212106-02-11, 1-QRV-111, May 18, 2002
- Drawing D-3378-609, Vessel Flange To Shell UT Calibration Block, Revision 10
- Drawing 232-442-6, Pressure Vessel Welding and Machining, Revision 6
- Eddy Current Examination Data Reports for the Unit 1 Steam Generator No. 14 Tubes
- Procedure 54-ISI-400-12, "Framatome Procedure: Multifrequency Eddy Current Examination of Tubing," Revision 12
- Procedure 01-EHP-4030-102-001, "Steam Generator Primary Side Surveillance," Revision 0
- Procedure 01-EHP-5037-SGP-003, "Steam Generator Primary Side Inspections," Revision 2
- Site Specific Eddy Current Data Analysis Guidelines, Revision 1

<u>Documents Related to Code Pressure Boundary Welding</u>

- Job Order 03171066-17, "2-FW-118-4, Weld Repair Excavated Areas," August 29, 2003
- Job Order R0209332-08, "1-MRV-210, Cut Reweld Vent Pipe," April 2002
  Weld Procedure Specification 1.2TS, Revision 2
- Procedure Qualification Record 234, March 29, 1989
- Procedure Qualification Record 235, March 30, 1989
- Procedure Qualification Record 255, August 8, 1989
- Weld Procedure Specification 5S-WP1/1/F4TB2-00, Revision 0
- Procedure Qualification Record PQ7094-00, Revision 0
- VT-2 Pressure Test Examination Record for 2-FW-118-4, August 29, 2003
- MT Examination Report for 2-FW-118-4 Thru Wall Leak Repair, August 25, 2003
- MT Examination Report for 1-MRV-210, May 22, 2002
- RT Examination Report for 1-MRV-210 Welds OW-1 & OW-2, May 22, 2002
- VT-2 Pressure Test Examination Record for 1-MRV-210, June 7, 2002

<u>Documents Related to Code Repairs or Replacements</u>

- Job Order 2037051-01, "1-SI-161-L1, Replace Nonconforming Stud Material," May 16, 2002
- Job Order 0024601904, "1-SI-158-L1, Replace Studs One for One," September 1, 2001
- Job Order R0212106, "Unit 1 Pressure Test," June 6, 2002

Documents Related to Steam Generator Tube Inspection Activities

- 51-5019137-00, "D. C. Cook Unit 1 U1C18 Operational Assessment," November 6, 2002
- 54-ISI-400-12, "Framatome Procedure: Multi-Frequency Eddy Current Examination of Tubing," Revision 12
- 51-5004764-04, "D. C. Cook Units 1 and 2 - Appendix H Eddy Current Technique Review," Revision 0
- SGD-DA-UT-C19, "Steam Generator Degradation Assessment," October 16, 2003
- Reactor Head Nozzle Penetration Remote Visual Inspection Plan For D. C. Cook Unit 1, Enclosure 1 Data Sheets, October 31, 2003
- Eddy Current Indication Reports, November 4, 2003
- 01-EHP-4030-102-001, "Steam Generator Primary Side Surveillance," Revision 0
- 01-EHP-5037-SGP-003, "Steam Generator Primary Side Inspections," Revision 2
- Site Specific Eddy Current Data Analysis Guidelines, Revision 1

1R11 Licensed Operator Requalification

- Licensed Operator Requalification Training Evaluation Scenario for December 9, 2003

1R12 Maintenance Effectiveness

- D. C. Cook Unit 1 and 2 TSs
- D. C. Cook UFSAR, Revision 18
- PMI-5035, "Maintenance Rule Program," Revision 9
- PMP-5035-MRP-001, "Maintenance Rule Program Administration," Revision 4
- Job Order 03294051, "Troubleshooting Plan for Degraded Grid Voltage Relay 1-27-T11A-1," October 22, 2003
- CR 03299018, "This CR Is Requesting an Evaluation, and Actions, Necessary to Remove a Calculation Requirement That the Degraded Grid and Loss of Voltage Relays Be Calibrated at a Monthly Frequency," October 26, 2003
- CR 02154052, "While Conducting Loss of Offsite Power/Loss of Coolant (LOP/LOCA) Testing Train B Section 4.2 Relay 1-27-t11a1 Undervoltage Relay Failed to Operate," June 6, 2002
- CR 03294051, "1-27-T11A-1, 4 kV [Kilovolt] Bus T11A Phase No.1 Undervoltage Relay, Failing to Actuate as Desired for the Testing per 1-OHP-4030-132-217B (Step 4.3.33)," October 21, 2003
- Cook Nuclear Plant’s Commitment Management System Commitment No. 3519, "Licensee Event Report 88-003-03," July 18, 1989
- 01-IHP-6030-IMP-309, "4 kV Bus Loss of Voltage and 4 kV Bus Degraded Voltage Relay Calibration," Revision 5
- Vendor Manual VTD-ASEA-0031, "ABB Power Distribution (Formerly ITE Imperial) Instructions for Single Phase Voltage Relays [Pub. No. IB 7.4.1.7-7]," Revision 1
- Vendor Manual VTD-ASEA-0042, "ABB Power Distribution (Formerly ITE Imperial) Circuit Description for High Accuracy Voltage Relay [Pub. No. CD 7.4.1.7-7]," Revision 0
- Vendor Manual VTD-ASEA-0041, "ABB Power Distribution (Formerly ITE Imperial) Instruction for Test Plug Units [Pub. No. IB 7.7.1.7-8]," Revision 0
- Drawing OP-1-98050-24, "Reserve Bus Transformer and Auxiliary Buses Low Voltage Protection Elementary Diagram," Revision 24

- Drawing PS-1-92070-11, "Control Room Auxiliary Relay Panel A8 and A9 Wiring Diagram," Revision 11
- Drawing PS-1-92047-7, "Station Auxiliary Panel "SA" Sheet No.2 Wiring Diagram," Revision 7
- Drawing PS-1-92067-2, "Control Room Auxiliary Relay Panel A3 and A4 Wiring Diagram," Revision 2
- Drawing OP-1-98034-30, "Diesel Generator 1AB Control Elementary Diagram," Revision 30
- Drawing OP-1-98035-31, "Diesel Generator 1CD Control Elementary Diagram," Revision 31
- Drawing OP-1-98043-44, "4 kV Diesel Generator 1AB Air Circuit Breaker Elementary Diagram," Revision 44
- Drawing OP-1-98044-40, "4 kV Diesel Generator 1CD Air Circuit Breaker Elementary Diagram," Revision 40
- LER 88-003-00, "Repetitive Violation of Engineered Safety Feature (ESF) Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," April 11, 1988
- LER 88-003-01, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances due to Highly Restrictive Allowable Values," July 29, 1988
- LER 88-003-02, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," April 7, 1989
- LER 88-003-03, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," July 18, 1989
- LER 88-003-04, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," September 11, 1989
- LER 88-003-05, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," December 28, 1989
- LER 88-003-06, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," February 6, 1990
- LER 88-003-07, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," March 8, 1990
- LER 88-003-08, "Repetitive Violation of ESF Instrumentation Limiting Conditions for Operation Tolerances Due to Highly Restrictive Allowable Values," June 22, 1990
- Work Request 02154052, "4 kV Bus T11A Phase No.1 Undervoltage Relay," June 3, 2002
- Job Order R0228922 Activity 01, "Perform 01-IHP-6030-IMP-309 4 kV Bus Undervoltage Relay Cal," June 4, 2002
- Job Order R0250874 Activity 01, "Perform 01-OHP-6030-IMP-309 4 kV Bus Undervoltage Relay Cal," September 26, 2003
- OP-1-98396-6, "Solid State Reactor Prot. and Safeguard System Power Supplies Train 'B' Elementary Diagram," Revision 6
- OP-1-98285-26, "Containment Spray System Elementary Diagram Sheet No.1," Revision 26
- OP-1-5144-37, "Flow Diagram Containment Spray Unit No. 1," Revision 37
- OP-1-98387-23, "Solid State Reactor Prot. and Safeguard System Safeguard Actuation Signal Train "B" Elementary Diagram," Revision 23
- CR 03308039, "Spare Parts Identified for Subject Relays Are Incorrect Type. Other Latching Slave Relays in SSPS [Solid State Protection System] Are Also Affected," November 4, 2003
- CR 03286022, "At 11:10 a.m. Both Train B Containment Spray Pump Discharge Valves 1-IMO-220 and 1-IMO-221 Were Found Open on Board Walkdown," October 13, 2003

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

- D. C. Cook Units 1 and 2 TSs
- PMP-2291-OLR-001, "On-Line Risk Management," Revisions 4 and 5
- PMP-2291-SCH-001, "Work Control Activity Scheduling Process," Revision 8
- PMP 4100-SDR-001, "Plant Shutdown Safety and Risk Management," Revision 6
- NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Section 11, "Assessment of Risk Resulting From Performance of Maintenance Activities," Revision 2
- ORAM Desktop Guide, Revision 8
- 01-OHP-5030-001-002, "Outage Risk Surveillance," Revision 3
- 01-OHP-5030.001.002, "Outage Risk Surveillance," Data Sheet 6, "Condition 6B System Availability Checklist," November 4, 2003 through November 12, 2003
- PMP-2291-OLR-001, "On-Line Risk Management," Data Sheet 1, "Work Schedule Review and Approval Form," Cycle 47, Week 6, September 28, 2003 through October 4, 2003
- PMP-2291-OLR-001, "On-Line Risk Management," Data Sheet 1, "Work Schedule Review and Approval Form," Cycle 48, Week 3, November 30, 2003 through December 6, 2003
- PMP-2291-OLR-001, "On-Line Risk Management," Data Sheet 1, "Work Schedule Review and Approval Form," Cycle 48, Week 4, December 7, 2003 through December 12, 2003
- Online T-1 Lookahead Production Schedule, Cycle-47, Week 6, September 28, 2003 through October 4, 2003
- Shift Manager's Logs, September 28, 2003 through October 1, 2003
- Shift Manager's Logs, October 24, 2003 through October 25, 2003
- CR 03317021, "The Shutdown Risk Program for the Shutdown Cooing Safety Function Assessment Tree in Condition 6B, Head Removed, Upper Internals Removed, Requires 'Number of Charging Pumps / Safety Injection Pumps Available with Power Operated Relief Valves.' The Power Operated Relief Valve Is Not Required in 6B," November 13, 2003
- PMP-2291-OLR-001, "Work Schedule Review and Approval Form Work Week Cycle 47 Week 10 (October 26 through November 1, 2003)"
- 01-OHP-4030-114-031, "Operations Weekly Surveillance Checks," Revision 0
- 02-OHP-4030-031, "Operations Weekly Surveillance Checks," Revision 1
- 12-OHP-SP-245, "TR-4 Only Switchyard Configuration Operation," Revision 0
- Design Information Transmittal B-01099-09, "Minimum Acceptable Voltages at the 4160 Volt and 600 Volt Safety Buses for Modes 1 through 6 and Defueled Condition," October 17, 2003
- DIT-B-02779-01, "Operations of Switchyard in Transformer No.4 Only Configuration," October 9, 2003
- DIT-B-02779-02, "Operations of Switchyard in Transformer No.4 Only Configuration," October 28, 2003
- DIT-B-02780-02, "Operations of Switchyard in Transformer No.4 Only Configuration Clarification," October 13, 2003
- D. C. Cook Nuclear Plant Standing Order No. SO-2003-0001, "Authorized Switchyard Maintenance/Work Activities," Revision 0
- Amendment No. 264 to DPR-74, "Donald C. Cook Nuclear Plant, Unit 2 - Issuance of Emergency Amendment Regarding One-Time Allowed Outage Time Extension for AB Emergency Diesel Generator (TAC No. MC1498)," December 10, 2003
- Unit 2 Control Room Logs, December 7 - 11, 2003

1R14 Personnel Performance During Non-routine Plant Evolutions

- NRC Information Notice 90-42, "Failure of Electrical Power Equipment Due to Solar Magnetic Disturbances," June 19, 1990
- CR 03273023, "Loss of Control Power to Operating Charging Pump Results in Loss of CVCS [Chemical and Volume Control System] Letdown," September 30, 2003
- CR 03277012, "Identified Loose Fuse Clip Holder During Inspection," October 4, 2003
- Drawing OP-1-98273-46, "Chemical and Volume Control System Reactor Coolant Charging Elementary Diagram," Revision 46
- Drawing OP-1-98274-18, "Chemical and Volume Control System Reactor Coolant Charging Elementary Diagram," Revision 18

1R15 Operability Evaluations

- D. C. Cook Units 1 and 2 TSs
- D. C. Cook UFSAR, Revision 18
- Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1
- OHI-4016, "Conduct of Operations Guidelines," Revision 8
- PMP-7030-OPR-001, "Operability Determinations," Revision 7
- 12-EHP-5043-EDC-001, "Evaluation of Discrepant Conditions," Revision 6
- 02-OHP-4023-E-3, "Steam Generator Tube Rupture," Revision 9b
- 02-OHP-4025-LS-3, "Steam Generator 2/3 Level Control," Revision 2
- 02-OHP-4025-LS-4, "Steam Generator 1/4 Level Control," Revision 2
- Proto-Power Corporation (Vendor) Calculation 00-140, "Determination of Acceptance Criteria for Functional Test to Verify Turbine Driven Auxiliary Feedwater Pump Flow Control Valve Position," Revision B
- CR 00300052, "Operability Determination Evaluation for the Unit 1 Steam Generator Tube Rupture Overfill Issue in Order to Support Unit 1 Restart," October 26, 2000
- CR 02290012, "Capability Calculations Show the Under Certain Conditions (Reduced Pressure in the 85 Psig to 80 Psig) the Steam Generator Power Operated Relief Valves Have Almost No Positive Margin," October 16, 2002
- CR 03305015, "Modes 1-4 Aggregate Operability Determination Evaluation for Unit 1," November 1, 2003
- CR 03323054, "Resolution of ODE's (Operability Determination Evaluations) Is Not Being Done in a Timely Manner," November 19, 2003
- CR 03016037, "Found Open Coil on Time Delay Relay for Safety Injection," January 16, 2003
- CR 03310043, "Non-Safety Related Bolt and Nut Installed in Safety Related Reactor Vessel Support," November 6, 2003
- NRC Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops," February 1, 1984
- DIT-S-01281-02, "Design Basis Documentation of the Reactor Vessel Support Bolts," November 12, 2003
- DIT-B-02816-00, "Load Capacity of the Replacement 1-1/2" Diameter Bolt for the Loop No.4 Hot Leg Reactor Vessel Support," November 8, 2003
- Drawing 1-2-3835-8, "Nuclear Steam Supply System Support Framing Reactor Vessel Support," Revision 8

- CR 03282025, "An Aluminum Work Plate (Approx. 2'x3'x3/16") Was Taken into Containment," October 9, 2003

1R16 Operator Workarounds

- PMP 4010-OWA-001, "Oversight and Control of Operator Workarounds," Revision 1
- Workaround Review Board Meeting Minutes, November 17, 2003
- Workaround Review Board Meeting Minutes, December 15, 2003
- D. C. Cook Unit 1 Control Room Logs, November 25-27, 2003
- D. C. Cook Unit 1 Blocked Alarm Index, November 28, 2003
- D. C. Cook Unit 1 Abnormal Position Control, November 28, 2003
- D. C. Cook Unit 1 Caution Tags, November 28, 2003
- CR 03329061, "Procedure Enhancements for 4021-001-002, Reactor Startup," November 25, 2003
- D. C. Cook Unit 1 TSs
- 01-OHP-4021-001-002, "Reactor Startup," Revision 29
- 12-EHP-4030-002-357, "Initial Criticality, All Rods Out Boron Concentration and Nuclear Heating Level," Revision 0
- 12-EHP-4030-002-356, "Low Power Physics Test with Dynamic Rod Worth Measurement," Revision 0d
- 01-IHP-6030-IMP-002, "Analog Rod Position Indication (NARPI) System Functional Test and Linearization," Revision 1

1R19 Post Maintenance Testing

- Limited Design Change Package 1-LDCP-5510, "Replace Emergency Diesel Generator Automatic Voltage Regulators 1-DGAB-VRCKT and 1-DGCD-VRCKT," Revision 0
- Job Order 03161014-02, "1-LDCP-5510, Replace Voltage Regulator," October 18, 2003
- Job Order 03161014-03, "Post Maintenance Test for Voltage Regulator," October 19, 2003
- Job Order 03161014-06, "1-LDCP-5510, Perform 12-EHP-6040-032-106," October 19, 2003
- Job Order 03161014-07, "1-LDCP-5510, Bench Test Spare Voltage Regulator," October 22, 2003
- Job Order 00267020, "1-CCW-178E, Adjust Stops, Repair / Replace Valve," November 7, 2003
- Job Order R0246476, "1-PP-10E, Change Oil in Bearing Reservoirs," November 7, 2003
- Job Order R0245571, "1-HE-15E, Inspect and Clean Heat Exchanger," November 7, 2003
- 12-EHP-6040-032-106, "Emergency Diesel Generator Control Panel Tests," Revision 0
- CR 03314027, "An On The Spot Change was required for 1-MOD-35624-TP-1, Emergency Diesel Generator 1CD Governor Replacement Modification Test For Step 4.1.10, Page 13," November 10, 2003
- CR 03316004, "During 1-MOD-35624-TP-1 3500 kW Load Rejection Test, the Digital Multimeter Read a Maximum Frequency of 65.6 Hz," November 12, 2003
- CR 03315051, "During the Performance of 1-MOD-35624-TP-1, Voltage Was Not Maintained Between 3740-4580 Volts AC as Required by Step 4.5.27.a for a >600 but <1000 kW Load Rejection," November 12, 2003
- CR 03317099, "1-MOD-35624-TP-1 Voltage and Frequency During Transient Conditions," November 13, 2003

- CR 03312045, "Jacket Water Goosenecks Leaking at Lower Flange Gasket," November 8, 2003
- CR 03315001, "Fill Valve for 1-QT-133-CD Stuck Open," November 11, 2003
- CR 03315013, "During the Performance of CD D/G run, Manually Started 1-QT-106-CD2 and Raised Level to 200 Gallons," November 11, 2003
- CR 03314076, "During the Performance of 1-MOD-35624-TP-1 it Was Noted That Steps 4.1.23e Would Not Work as Sequenced," November 10, 2003
- CR 03313034, "Starting Air Compressor for 1CD EDG Failed to Start When Switch Placed in Auto," November 9, 2003
- CR 03324047, "DG1CD Surveillance Procedure Has Not Been Updated Completely to Incorporate the New Modification Done on the Governor," November 20, 2003
- Job Order 03055043, "Perform 1-LDCP-5372, Replace 1-XPS-217 and XPA-217," November 10, 2003
- Job Order 01045019, "1-OME-150-CD-EN, Jacket Water Leak at Cylinder Head to Liner 6RB," November 11, 2003
- 1-MOD-35624-TP-1, "Emergency Diesel Generator 1CD Governor Replacement Modification Test," Revision 1
- Job Order 02165077, "1-IMO-315, Packing Leak," November 8, 2003
- Job Order 03304007, "1-IMO-315, Disassemble, Inspect, Repair Valve," November 9, 2003
- CR 03310021, "During Reassembly of IMO-315 (Just Before Consolidation of the Packing Was to Begin), Scoring on the Valve Stem Was Noted," November 6, 2003
- CR 03304007, "During as Found Diagnostic Testing, Found Anomalies Indicative of Internal Valve Problems," October 31, 2003
- CR 02165077, "1-IMO-315 Was Found to Have a Packing Leak During the Initial Containment Walkdown Following the Trip of Unit 1 on June 14th 2002," June 14, 2002
- Drawing OP-1-5143-61, "Flow Diagram Emergency Core Cooling (RHR) Unit No. 1," Revision 61
- Drawing 1-SI-25, "Safety Injection Piping," Revision 17
- Drawing 1-SI-26, "Safety Injection Piping," Revision 13
- Drawing 1-SI-27, "Safety Injection Piping," Revision 13

<u>1R20</u> <u>Refueling Activities</u>

- D. C. Cook Units 1 and 2 TSs
- D. C. Cook UFSAR, Revision 18
- 01-OHP-4021-001-001, "Plant Heatup From Cold Shutdown to Hot Standby," Revision 32
- 01-OHP-4021-001-004, "Plant Cooldown From Hot Standby to Cold Shutdown," Revision 40a
- 01 OHP 4021-017-002, "Placing In Service the Residual Heat Removal System," Revision 16a
- 01-OHP-4030-114-030, "Daily and Shiftly Surveillance Checks," Revision 2
- 01-OHP-4021-001-002, "Reactor Startup," Revision29
- 12-OHP-4050-FHP-001, "Refueling Procedure Guidelines," Revision 5
- 12-OHP-4050-FHP-005, "Core Unload/Reload and Incore Shuffle," Revision 4
- 01-OHP-4030-227-041, "Refueling Integrity," Revision 0
- 12-EHP-4030-002-356, "Low Power Physics Tests with Dynamic Rod Worth Measurement," Revision 0D
- PMP 4100-SDR-001, "Plant Shutdown Safety and Risk Management," Revision 6

- NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors," June 9, 2003
- Shift Manager's Logs, October 18 through November 26, 2003
- U1C19 Refueling Outage Schedule Shutdown Risk Review, October 16, 2003
- CR 03295045, "Screenhouse Diving Accident and Stop Work Order Implementation," October 21, 2003
- CR 03298026, "As a Result of Past and Current Reactor Coolant System Leakage at the Flange Connection on #12 Reactor Coolant Pump, it is Required to Inspect the Reactor Coolant Pump Flange Cap Screws (Known as Flange Bolts by Most) for Degradation Caused by Boric Acid Deposits," October 25, 2003
- CR 03310059, "During the Restoration from Drain Down Numerous Leaks Occurred Resulting in the Contamination of Several Rooms and Preventing Continuing the Refill of the Reactor Coolant System," November 6, 2003
- CR 03311009, "The Reactor Coolant System was Overfilled During Restoration from RCS Draindown Resulting in Overflow to the Lower Cavity," November 7, 2003
- CR 03313009, "Volume Control Tank Level Cannel QLC-452 was Found with its Root Isolation Valve 1-QLC-452-V1 Closed Wen it Should Have Been Open," November 9, 2003
- CR 03317088, " at 1330 on November 13, 2003 Valve 1-RH-142 was Breeched by Mistake. The Valve that was Scheduled for Maintenance was 1-CTS-131W," November 13, 2003
- CR 03316009, "Manipulator Crane Load Cell Indication Failed While Inserting Fuel Assembly into Core," November 12, 2003
- CR 03319099, "Containment Evacuation was not Expeditiously Performed Following the Containment Evacuation Alarm in Unit 1," November 15, 2003
- CR 03324002, "A Walkdown in the Lower Plenum of the Ice Condenser Identified Two Concerns that Need to Be Addressed," November 20, 2003
- CR 03325008, "During the NRC containment Close-out Tour for Mode 4 Various Discrepancies Were Noted Including Foreign Material and Material Condition Issues," November 21, 2003
- CR 03325068, "During an NRC Walkdown of the Upper Plenum of the Ice Condenser, the Following Items Were Discovered," November 21, 2003
- CR 03314003, "The High Flux at Shutdown Alarm was Actuated When the First Fuel Assembly was Loaded into the Vessel During the U1C19 Outage," November 10, 003
- CR 03319099, "Containment Evacuation was not Expeditiously Performed Following the Containment Evacuation Alarm in Unit 1," November 15, 2003
- CR 03329032, "During an NRC Walkdown of the Ice Condenser, a Damaged Cable and an Open Hole in an Electrical Junction Box Were Discovered," November 25, 2003
- Drawing OP-1-5143-61, "Flow Diagram Emergency Core Cooling (RHR) Unit No. 1," Revision 61
- 01-OHP-4021-002-013, "Reactor Coolant System Vacuum Fill," Revision 2
- Drawing 1-5663-7, "Unit 1 Reactor Coolant System Loop Details," Revision 7
- Drawing OP-1-5128-21, "Flow Diagram Reactor Coolant Unit No. 1," Revision 21
- Drawing OP-1-5128A-46, "Flow Diagram Reactor Coolant Unit No. 1," Revision 46
- Drawing OP-12-5137-25, "Flow Diagram Waste Disposal System Vents & Drains," Revision 25

<u>1R22</u> <u>Surveillance Testing</u>

- 01-EHP-4030-109-237, "Containment Spray and Residual Heat Removal Check Valve Leak Rate Test," Revision 2

- 01-OHP-4030-119-022E, "East Essential Service Water System Test," Revision 2a
- Technical Data Book Figure 1-19.1, "Power Operated Valve Stroke Time Limits," Revision 68
- Technical Data Book Figure 1-15.1, "Safety Related Pump Inservice Test Hydraulic Reference," Revision 80
- Technical Data Book Figure 1-15.2, "Safety Related Pump Inservice Test Vibration Reference," Revision 73
- NRC Commitment 891, "Differential Pressure Acceptance Criteria for 1-ESW-101," March 19, 1993
- D. C. Cook UFSAR, Revision 18
- NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors," June 9, 2001
- NRC Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," July 14, 1998
- 12-THP-6020-CHM-106, "Ice Condenser," Revision 2c
- 1-OHP-4030-108-008R, "ECCS Check Valve Test," Attachment 8, "Accumulator Check Valve Test," Revision 1
- 01-OHP-4030-STP-017CS, "Main and Auxiliary Feedwater System Shutdown Testing," Attachment 1, "Turbine Driven Auxiliary Feedwater Pump Check Valve Test," Revision 8
- 12-MHP-4030-031-001, "Inspection of Lower Containment and Recirculation Sumps," Revision 2
- DIT-S-00408-00, "Containment Recirculation Sump and Lower Containment Sump Inspection Requirements," Revision 0
- DIT-B-02806-00, "01-OHP-4030-156-017CS Attachment 1 TDAFP Check Valve Test," Revision 0
- DIT-B-02806-01, "01-OHP-4030-156-017CS Attachment 1 TDAFP Check Valve Test," Revision 1
- DIT-B-01872-02, "Accuracy of Auxiliary Feedwater Flow As Read at the Output of 1-FFI-210, 220, 230 and 240," Revision 2
- Engineering Modification 1-CMM-30090, "Partial Removal of the Lower Portion of the Abandoned In-place Instrument Guard Pipe Assemblies in the Unit 1 Containment Recirculating Sump," Revision 0
- Job Order 03320060-01, "Eliminate Gaps in Sump Screen," November 18, 2003
- Job Order R0230975-06, "549 Day Surveillance of the Containment Sumps," November 16, 2003
- CR 03153007, "An Expanded Sampling of Unit 2 Ice Condenser Baskets Around Basket B15, A7, R9 with Low Boron Content Showed Two of the Five Additional Baskets with Boron Concentrations Below 1800 Parts per Million," June 2, 2003
- CR 03297073, "Revision 1 to 1-OHP-4030-108-008R Changed the Testing Method for Accumulator Check Valve Testing, Attachment 8 Such That the Only Acceptance Criteria Is Obtained by Non-intrusive Equipment," October 24, 2003
- CR 03320061, "In the Unit 1 Recirculation Sump, Corrosion Was Found on Pipe Stantion Mounting Bolting at Floor and Missing Bolting on Pipe Stantion Mounts at Floor of Sump," November 16, 2003
- CR 03324004, "During the Final Close Out Tour of the Lower Containment Recirculation Sump by the Maintenance Mechanical Manager and the NRC Inspector Material Condition Discrepancies Were Found," November 20, 2003

- CR 03322049, "NRC Resident Had Observations of the Lower Containment and RHR Recirculation Sump," November 18, 2003
- CR 02150019, "While Performing Recirculating Sump Inspection, (3) Bolts Were Found to Be Missing on Lower Brackets of Instrumentation Columns and Small Areas of Peeling Coatings Were identified on the Walls," May 30, 2002
- CR 03315031, "Attachment 1 of 01-OHP-4030-156-017CS Does Not Contain All Limitations from Design Information Transmittal B-01872-02," November 11, 2003
- CR 03320060, "Lower Containment Sump 1-PP-38B Screen Wire Mesh Located Between Floor and Cover Plate Has Small Gap at Top Edge of Left Screen Section and Small Gap at Bottom of Right Screen Section," November 16, 2003
- CR 03349055, "Gaps Identified in the Unit 1 Lower Containment Sump Screens May Not Have Been Corrected," December 15, 2003
- CR 03276032, "Appears to Be a Typo in 01-OHP-4030-119-022E, Step 5.1," October 3, 2003
- Job Order R0210938, "Perform 1-IHP-4030-STP-100 (Train B)," November 16, 2003
- CR 03293069, "1-11B12 Failed to Trip When Phase B Was Initiated," October 20, 2003
- CR 03294074, "During Section 4.2 of 1-OHP-4030-132-217B, the West ESW Breaker Closed Faster Than the Allowable Time in the Acceptance Criteria Step 5.18," October 21, 2003
- CR 03295014, "During Performance of 1-OHP-4030-132-217B, (Train B) Load Sequence Testing, the AB DG Exceeded the Maximum Allowed Frequency During the 600 kW Load Rejection Test," October 22, 2003
- CR 03304065, "Train B LOP / LOCA Attachment No.24 Has Improper Restoration Sequencing Which Would Result in an Undesired Actuation Which Was Previously Blocked," November 1, 2003
- 01-OHP-4030-217B, "DG1AB Load Sequencing and ESF Testing," Revision 4

1R23 Temporary Modifications

- 12-EHP-5040-MOD-001, "Temporary Modifications," Revision 11
- PMP-2350-SES-001, "10 CFR 50.59 Reviews," Revision 1A
- 12-THP-6010-RPP-015, "Temporary Shielding," Revision 3
- 1-TM-03-80-R0, "Install Temporary Shielding on Unit 1 RHR Heat Exchanger," Revision 0
- 1-TM-03-80-R0, "Tap Changes for the Unit 1 Auxiliary Transformers 1-TR1AB and 1-TR1CD During the Unit 1 Refueling Outage (U1C19)," Revision 0
- Vendor Instruction Manual for TTR Transformer Turn Ratio Test Sets
- UFSAR Section 2.9, "Plant Design Criteria for Structures and Equipment"
- Job Order R0248311, "Install Shielding Unit 1 East & West RHR Heat Exchanger’s"
- Job Order 03111005, "1-TR1AB, Change Tap While Unit Is on Backfeed"
- Job Order 03111006, "1-TR1CD, Change Tap While Unit Is on Backfeed"

1EP6 Emergency Preparedness Drill Evaluation

- PMP-2080-EPP-101, "Emergency Classification," Revision 3b
- PMP-2080-EPP-107, "Notification," Revision 17
- RMT-2080-TSC-001, "Activation and Operation of the Technical Support Center," Revision 3
- Timeline With Initial Actions, Emergency Response Drill, September 30, 2003
- Emergency Response Drill Exercise Messages, September 30, 2003

- EMD-32A, "Nuclear Plant Event Notification," Drill Messages for Declared Unusual Event, Alert and Site Area Emergency, September 30, 2003
- Emergency Planning Observation Cards 20,767, 20,772 and 20,813; Observation Comments
- Regarding Objectives in Emergency Operations Facility, Public Affairs, and Technical Support Center, September 30, 2003
- CR 03279007, "Quick Hit Self-Assessment for Emergency Response Organization Training Drill Conducted September 30, 2003," October 6, 2003
- CR 03273027, "Property Keys for Gates and Thorton Road Access Were Changed Out in Years Gone By and These Accesses are Blocked Off," September 30, 2003

4OA1 Performance Indicator Verification

- Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2
- PMP-7110.PIP.001, "Regulatory Oversight Program Performance Indicators," Revision 1
- Letter from J. Pollock, American Electric Power, to the US NRC, Subject: "Cook Unit 1 and 2 -- 4Q2002 -- PI [Performance Indicator] Data Elements (QR and CR)," January 21, 2003
- Letter from J. Pollock, American Electric Power, to the US NRC, Subject: "Cook Unit 1 and 2 -- 1Q2003 -- PI Data Elements (QR)," April 21, 2003
- Letter from M. Finissi, American Electric Power, to the US NRC, Subject: "Cook Unit 1 and 2 -- 2Q2003 -- PI Data Elements (CR)," July 23, 2003
- Letter from M. Finissi, American Electric Power, to the US NRC, Subject: "Cook Unit 1 and 2 -- 3Q2003 -- PI Data Elements (QR and CR)," October 22, 2003
- Administrative Technical Requirements Units 1 and 2, Reactor Coolant System, Supplemental Operational and Surveillance Requirements, Revision 32
- OHI-4032, "Leakage Monitoring Program," Revision 2
- Licensee Event Reports, October 1, 2002 through September 30, 2003
- NRC Information Notice 94-46, "Non-conservative Reactor Coolant System Leakage Calculation," June 20, 1994
- CR 03318080, "Unit 2 RCS Leakage has been Somewhat Higher During This Cycle U2C14 than the Previous Cycle," November 14, 2003

4OA2 Identification and Resolution of Problems

Degraded ESW Pump Bearings

- Root Cause Analysis Report (CR 03158021), "Essential Service Water Pump Degraded Bowl Bearing Root Cause," August 19, 2003
- Limited Design Change Package 12-LDCP-5260, "Essential Service Water Pump Upgrades for Reliability," Revision 0
- Dedication Plan No. HP-0138, "Essential Service Water Pump Bearings," June 17, 2002
- Engineering Modification E-Mod/CMM No. 12-MOD-35623, "ESW Pump Bowl Bearing Replacement 1(2)-PP-7E, 1(2)-PP-7W," Revision 0a
- Nonconformance Report (NCR) No. 2479 (Johnston Pump Company), "AEP - D. C. Cook Pump Impeller Design Clearance Evaluation," June 6, 2003
- 01-OHP 4030-119-022W, "West Essential Service Water System Test," Revision 2a
- CR 00246034, "1-RC-106-L3," September 2, 2000

- CR 01242063, "1-SI-158-L1," August 30, 2001
- CR 01249074, "1-SI-158-L1," September 6, 2001
- CR 02031007, " Linear Indication Identified During VT-1 on Steam Generator Manway Studs and Nuts," January 31, 2002
- CR 02130031, "1-RC-108-L2," May 10, 2002
- CR 02133049, "Boric Acid Leakage at 1-RC-108-L2," May 10, 2002
- CR 02027053, "Linear Indication Found on Baffle Plate Weld," January 27, 2003
- CR 03097025, "NRC Information Notice 2002-21 Supplement 1," April 7, 2003
- CR 03156076, "NRC Information Notice 2003-05," June 5, 2003
- CR 03248051, "NRC Information Notice 2003-13," September 5, 2003
- CR 03158021, "Examination of the Previously Installed 1E and 2E ESW Pump Bowls Identified Bearing Damage and Adhesion of Bearing Material to the Pump Shaft," June 7, 2003

Unit 1 Reactor Trip Due to Fire in Main Transformer

- LER 50-315/2003-001-00, "Unit Turbine Trip and Reactor Trip Due to Main Transformer Fault and Fire," March 17, 2003
- Root Cause Evaluation (CR 03016007), "Unit 1 Reactor Trip Due to Fire in Main Transformer," June 17, 2003
- Event Notification 39513, January 15, 2003
- Shift Manager's Logs, January 15, 2003
- PMP 4010-TRP-001, "Reactor Trip Review," January 16, 2003
- CR 03016003, "Unit 1 Main Steam Stop Valves Drifted in the Closed Direction When Unit 1 Tripped," January 16, 2003
- CR 03016007, "Unit 1 Reactor Trip Due to Fire in Main Transformer," January 16, 2003
- CR 03016032, "Unit 1 Oscillograph Failed to Function Following Automatic Reactor/Turbine Trip Due to Main Transformer Fault," January 16, 2003
- CR 03045051, "Cooling to the Reserve Auxiliary Transformers Is Lost in the Event of a Main Transformer Deluge System Actuation Combined with Operation of Either the Unit Differential Relays or the Overall Differential Relays," February 14, 2003
- CR 03052007, "Perform Self-Assessment SA-2003-CAP-004 Event Analysis for the Unit 1 Main Transformer Fire and Reactor Trip January 15, 2003," February 21, 2003

4OA3 Event Follow-up

- LER 50-315/2003-001-00, "Unit Turbine Trip and Reactor Trip Due to Main Transformer Fault and Fire," March 17, 2003
- LER 50-315/1998-020-00, "Containment Recirculation Sump pH Upper Limit Exceeded Due to Analysis Input Omission," April 8, 2001
- LER 50-315/1998-020-01, "Containment Recirculation Sump pH Upper Limit Exceeded Due to Analysis Input Omission," Supplement 1, July 28, 1998
- LER 50-315/1998-020-02, "Containment Recirculation Sump pH Upper Limit Exceeded Due to Analysis Input Omission," Supplement 2, March 16, 2001
- MD-12-CTS-118-N, "Containment Spray System and Recirculation Sump Minimum and Maximum pH," Revision 4
- NCE-60343, "Environmental Qualification Evaluation of EQ Equipment for Revised Containment Spray pH Range," Revision 3

- Design Basis Document – DB-12-CTS, "Containment Spray System," Revision 0, with Change Sheet 6
- SS/SE 2000-0806-00, Addendum, 99-UFSAR-1267, "UFSAR Changes from pH Calculations," May 12, 2000
- Westinghouse Letter AEP-98-07, "Maximum Sump pH - Justification for Past Operation," May 15, 1998
- D. C. Cook Unit 1 TS; Sections 3/4.1.2 and 3/4.5.5.
- CR P-98-01287, "Written When Westinghouse Determined that the Sodium Hydroxide Contained Within the Ice Condenser Ice Beds Was Not Included in the BORDER Analysis Calculation," March 26, 1998
- CR P-98-01292, "Submittal AEP:NRC 0916W Did Not Propose Change for TS Basis 3/4.6.2.2, the Range of pH Should Have Been Changed from 8.5 to 11.0 to 7.6 to 9.5," March 26, 1998
- CR P-99-04887, "Inadequate Closure of CR 93-1094 to Address Westinghouse Potential Part 21 Regarding Containment Spray and Sump pH During Small Break Loss of Coolant Accident," March 10, 1999
- CR P-00-04441, "Calculation MD-12-CTS-118-N, Revision 1 Was Completed as a Restricted Calculation with Limitations," March 20. 2000
- CR 01298030, "Track the Configuration Impacts of MD-12-CTS-118-N, Containment Spray System and Recirculation Sump Minimum and Maximum pH, Revision 4," October 25, 2001

4OA5 Other Activities

.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

Condition Reports

- CR 02144019, "Indication of Penetration 62," May 23, 2002
- CR 02136042, "Inactive/Passive Boric Acid was Found on the Top of the Reactor Vessel Head," May 16, 2002
- CR 03137028, "Rust Staining on Reactor Vessel Head and Annular Area of Penetration 17," May 17, 2003
- CR 03155017, "Number of Indications on Two Unit 2 Upper Head Penetrations Do Not Match," June 3, 2003
- CR 03168049, "Active Leak During NOP/NOT Walkdown," June 17, 2003

Drawings

- 233-447-0, "Closure Head Machining," Revision 0
- 233-452-1, "Control Rod Penetration Details," Revision 1

Nondestructive Examination Reports

- MRS-SSP-1319, "Reactor Vessel Head Penetration Remote Visual Inspections for Cook, Unit 1 - Final Inspection Report," May 17, 2002
- UT Examination Report For Penetration 62, May 17, 2002
- D. C. Cook 1 Reactor Vessel Head Penetration Inspection Final Report, July 1, 2002
- Unit 1 Head Examination Report (C0017393), February 28, 1994

Other Documents

- Westinghouse Letter, "Report LTR-RCDA-0377," Revision 2
- DIT S-00705-04, "Unit and Cycle Specific Burnup Related Data," October 20, 2003
- Westinghouse Letter "AEP-03-78, Reactor Vessel Upper Head Mean Bulk Fluid Temperature," October 17, 2003
- R0072394, Unit 1 Pressure Test, December 15, 2000
- 03117014, "Visual Examination of Unit 1 Lower Vessel Head Insulation Data Sheet 1," May 17, 2003
- Reactor Head Nozzle Penetration Remote Visual Inspection Plan For D. C. Cook Unit 1, October 6, 2003

Procedures

- PDP-7040-001, "Qualification and Certification of Inspection, Test, Examination, and NDE Personnel," Revision 2
- 54-ISI-367-05, "Procedure for Visual Examination for Leakage of Reactor Head Penetrations," Revision 5, Change 1
- 02-0HP-4030-001-002, "Containment Inspection Tours," Revision 18
- PMP-5030-001-001, "Boric Acid Corrosion of Ferritic Steel Components and Material," Revision 6
- 12-QHP-5070-NDE-002, "Visual VT-2 Examinations: Inservice and Repair/Replacements," Revision 3a

.2 TI 2515/152, RPV Lower Head Penetration Nozzles (NRC Bulletin 2003-02)

Chemical Sample Analysis Reports

- 03300978, 1 East Wall, October 28, 2003
- 03300961, P 12/23/47, October 24, 2003
- 03300983, P51, October 28, 2003
- 03300981, P22, October 28, 2003
- 03300982, P38, October 28, 2003
- 03300984, West Wall, October 28, 2003
- Cook Unit 1 Lower Head Deposit Sample Results, November 7, 2003

Drawings

- 3790D-6, "Section and Details of Hemispheric Bottom," Revision B
- 3790D-1, "Elevation of Reactor Vessel and Typical Panel Sections," Revision C
- 3790D-10, "Section and Details of Removable Dome Insulation," Revision B
- 3790D-9, "Plan View of Dome Removable Insulation," Revision A
- 233-456-6, "Instrument Penetration Assembly and Details- Bottom Head," Revision 0

Procedures

- GLG.911, "Chemistry Lab Guide for Deposits Sample and Analysis," Revision 1
- 12-QHP-5050-NDE-027, "Visual Examination For Boric Acid And Condition Of Component Surfaces," Revision 0

LIST OF ACRONYMS USED

ADAMS	Agency-wide Documents and Management System
AC	Alternating Current
AEP	American Electric Power
ASME	American Society of Mechanical Engineers
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
CRID	Control Room Instrument Distribution
CST	Condensate Storage Tank
CTS	Containment Spray
CVCS	Chemical and Volume Control System
DG	Diesel Generator
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
EHP	Electrical Maintenance Head Procedure
ESW	Essential Service Water
ESF	Engineered Safety Feature
IHP	Instrument Maintenance Head Procedure
IMC	Inspection Manual Chapter
kV	Kilovolts
kW	Kilowatts
LER	Licensee Event Report
MHP	Maintenance Head Procedure
MT	Magnetic Particle Testing
NARPI	Analog Rod Position Indication
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OA	Other Activities
OHP	Operations Head Procedure
OWA	Operator Work-Around
PARS	Publically Available Records
PI	Performance Indicator
PMI	Plant Manager’s Instruction
PMP	Plant Manager’s Procedure
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SSCs	Structures, Systems, and Components

LIST OF ACRONYMS USED (con't)

SSPS	Solid State Protection System
STP	Surveillance Test Procedure
TDAFP	Turbine Driven Auxiliary Feedwater Pump
TI	Temporary Instruction
TS	Technical Specification
U1C19	Unit 1 Cycle 19 Refueling Outage
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Testing
VHP	Vessel Head Penetration
VT	Visual Testing