July 29, 2003

EA-03-058

Mr. A. C. Bakken III
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 50-315/03-06; 50-316/03-06

Dear Mr. Bakken:

On June 30, 2003, the NRC completed an inspection at your D. C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on June 25, 2003, with Mr. J. Pollock 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 Non-Cited Violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region III; 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 facility.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calender year '02 and the remaining inspection activities for D.C. Cook were completed in

January 2003. The NRC will continue to monitor overall safeguards and security controls at the D.C. Cook facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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 50-315/03-06; 50-316/03-06
w/Attachment: Supplemental Information

cc w/encl: J. Pollock, 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:	50-315/03-06; 50-316/03-06
Licensee:	Indiana Michigan Power Company
Facility:	D. C. Cook Nuclear Power Plant, Units 1 and 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	April 1, 2003, through June 30, 2003
Inspectors:	B. Kemker, Senior Resident Inspector I. Netzel, Resident Inspector R. Daley, Reactor Engineer C. Phillips, Senior Operations Engineer W. Slawinski, Senior Radiation Specialist R. Winter, Reactor Engineer
Approved by:	Eric R. Duncan, Chief Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000315-2003-06, IR 05000316-2003-06; Indiana Michigan Power Company; 04/01/2003 - 06/30/2003; D. C. Cook Nuclear Power Plant, Units 1 and 2; Maintenance Effectiveness; Event Response.

This report covers a 3-month period of baseline inspections. The inspections were conducted by resident and region based inspectors. Two Green findings with associated Non-Cited Violations (NCVs) were identified. 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The licensee failed to take effective corrective actions to address Unit 2 CD emergency diesel generator (EDG) load oscillations that occurred on November 2, 2002, to prevent recurrence of these oscillations on January 26, 2003.

  This finding was more than minor since the repetitive Unit 2 CD EDG load oscillations were associated with the Configuration Control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance because the impact of the unavailability of the EDG on overall plant risk was not significant. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified. (Section 1R12)

Cornerstone: Initiating Events

- Green. The licensee failed to take effective corrective actions to address age-related failures of reactor control instrumentation power supplies and prevent an automatic Unit 2 reactor trip on February 5, 2003, due to the failure of similar power supplies.

  This finding was more than minor because, if left uncorrected, it would become a more significant safety concern since continued failures of reactor control instrumentation power supplies could result in additional reactor trips and challenge safety-related equipment. The finding was of very low safety significance because all mitigating systems were available during the event. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified. (Section 4OA3.1)

B. Licensee Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Both units operated at or near full power during the inspection period until April 24, 2003, when operators manually tripped both units in response to traveling water screen fouling and lowering condenser vacuum caused by a large influx of fish which damaged the traveling water screens. An Alert was declared due to degraded essential service water (ESW) conditions and subsequently exited after affected safety-related equipment was reliably restored. Following repairs, the licensee performed a reactor startup and synchronized Unit 1 to the grid on May 28, 2003. Following completion of a planned refueling outage, the licensee performed a reactor startup and synchronized Unit 2 to the grid on June 20, 2003. Both units operated at full power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed licensee procedures and preparations for hot weather and high winds. The inspectors reviewed severe weather procedures, emergency plan implementing procedures related to severe weather, annunciator response procedures, and performed walkdowns. During walkdowns of the plant and switchyard conducted the week of May 11, 2003, the inspectors verified that material capable of becoming an airborne missile hazard during high wind conditions or severe weather was appropriately restrained. Additionally, the inspectors reviewed condition reports (CRs) and verified that problems associated with adverse weather were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

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

- Unit 1 West Residual Heat Removal Train (risk significant train recently aligned)
- Unit 2 Spent Fuel Pool Cooling Train (risk significant with Unit 2 core offloaded)
- Unit 2 Chemical and Volume Control System (risk significant train recently aligned)

The inspectors reviewed operating procedures, system diagrams, Technical Specification (TS) requirements, Administrative Technical Requirements, 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.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours

a. Inspection Scope

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

- Unit 1 Transformer Room (Fire Zone 14)
- Unit 1 Reactor Cable Tunnel (Fire Zones 7 through 12)
- Unit 2 Reactor Cable Tunnel (Fire Zones 22 through 27)
- Unit 1 Safety Injection Pump Rooms (Fire Zones 64A and 64B)
- Unit 2 Safety Injection Pump Rooms (Fire Zones 65A and 65B)
- Unit 1 Lower Containment Building (Fire Zones 66 and 67)
- Unit 2 Lower Containment Building (Fire Zones 74 and 75)

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.

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation

a. Inspection Scope

The inspectors assessed fire brigade performance and the drill evaluators' critique during a fire brigade drill on June 24, 2003. The drill simulated an electrical fire in an inverter cabinet in the Technical Support Center Inverter Room. The inspectors focused on the command and control of fire brigade activities, fire fighting and communication practices, material condition and use of fire fighting equipment, and implementation of pre-planned fire fighting strategies.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed completed test reports and observed the performance of inspections for the following heat exchangers following the April 24, 2003, fish intrusion event:

- 1-HE-15E Unit 1 East Component Cooling Water (CCW) Heat Exchanger
- 1-HE-15W Unit 1 West CCW Heat Exchanger
- 2-HE-15E Unit 2 East CCW Heat Exchanger
- 2-HE-15W Unit 2 West CCW Heat Exchanger

The inspectors selected these heat exchangers because the CCW system was risk significant in the licensee's risk assessment and were required to support the operability of other risk significant safety-related equipment. During these inspections, the inspectors observed the as-found condition of the heat exchangers and verified that no deficiencies existed that would mask degraded performance. The inspectors discussed the as-found condition as well as the historical performance of the heat exchangers with engineering department personnel and reviewed applicable documents and procedures.

In addition, the inspectors verified that heat sink problems were entered into the corrective action program with the appropriate significance characterization, and that completed corrective actions were adequate and appropriately implemented.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

Through a review of records and in-process observation of non-destructive examinations, the inspectors evaluated the implementation of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system and risk significant piping systems.

From May 13 through 15, 2003, the inspectors observed the following activities inside the Unit 2 containment:

- ultrasonic (UT) examination of steam generator 24 nozzle-to-shell weld STM-24-MSN;
- UT examination of steam generator 24 nozzle inner radius STM-24-MSN-IRS; and

- magnetic particle examination of steam generator 24 nozzle-to-shell weld (STM-24-MSN).

From May 20 through 23, 2003, the inspectors reviewed repair and replacement records required by Sections III, IX, and XI of the American Society of Mechanical Engineers (ASME) Code for the following activities:

- replacement of 2-inch loop isolation valve 1-RC-102-L2; and
- removal and reinstallation of a section of 6-inch piping to support repairs to charging pump 2-PP-50W.

The inspectors reviewed inservice inspection related problems that were identified by the licensee and entered into their corrective action program to confirm that the licensee had appropriately described the problems, had an appropriate threshold for identifying issues, and had implemented effective corrective actions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of Job Performance Measure operating tests and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from February 19 through March 28, 2003. The overall results were compared with the significance determination process in accordance with NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)."

b. Findings

No findings of significance were identified.

.2 Resident Inspector Quarterly Review

a. Inspection Scope

On June 24, 2003, the inspectors assessed licensed operator performance and the training evaluators' critique during licensed operator annual requalification evaluations in the simulator. The inspectors focused on alarm response, command and control of crew activities, communication practices, procedural adherence, and implementation of emergency plan requirements.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- Repetitive Unit 2 CD Emergency Diesel Generator Governor Failures
- Unit 1 and Unit 2 Turbine Driven Auxiliary Feedwater Pump Trip Throttle Valve Alignment Issues

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the SSCs. Specifically, the inspectors reviewed the licensee's actions to address SSC performance 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).

b. Findings

b.1 Failure to Correct Conditions Causing Repetitive Load Swings on the Unit 2 CD EDG

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," when the licensee failed to take effective corrective actions to prevent repetitive load oscillations on the Unit 2 CD EDG.

Discussion

On November 5, 2002, the Unit 2 CD EDG experienced unexpected 150 kilowatt (kW) load oscillations during surveillance testing. The engine was shut down and re-started for troubleshooting. At this point, 200 kW load oscillations occurred and the engine was shut down. To correct these load oscillations, the licensee replaced the electronic governing module (EGM) and the governor hydraulic actuator (EGB). The licensee's troubleshooting team determined that the most likely cause of the load oscillations was a problem with the EGM. The team, however, could not definitively rule out the EGB as a potential source. Therefore, in the interest of time, the licensee decided to replace both the EGM and EGB, and identify which caused the load swings through subsequent vendor testing. Following replacement, adjustments were made to potentiometers on the newly installed EGM to restore the EGM to service. Following these adjustments, engine speed started to oscillate significantly, resulting in large swings in generator field amperage and voltage. During one oscillation, when field voltage approached the upper peg of the control room meter, operators tripped the EDG. Rather than troubleshoot the newly installed EGM, the licensee decided to replace the module with another spare EGM. The engine was again started to support full load testing. After successfully paralleling with offsite power, engine load was increased to 3500 kW and load swings of approximately 500 kW were experienced. A check of hydraulic actuator oil level revealed no oil visible in the sight glass. The engine was tripped locally. After the engine was shut down, visible oil level returned to the sight glass, indicating that oil was not lost from the actuator. Since the licensee believed that the original EGB was fully functional, the original EGB was reinstalled on the engine. In the end, replacement of the EGM appeared to have corrected the load oscillations.

The licensee’s root cause evaluation determined that the cause of the load oscillations was the failure to ensure that adequate repairs were completed following a fire in the EGM in 1992, since some of the internal components potentially affected by the fire were not replaced. The root cause for the failure of the replacement EGM to control speed was improper setup prior to installation. This was due to a lack of knowledge on how to test and prepare the module for installation. Numerous equipment failures and the need for additional troubleshooting prevented completion of corrective maintenance and testing activities within the 72-hour allowed outage time of TS 3.8.1.1.b. The licensee requested and received a Notice of Enforcement Discretion (NOED) for an additional 72 hours to accomplish restoration of the EDG to preclude a required unit shutdown.

On January 23, 2003, the Unit 2 CD EDG was removed from service for planned maintenance. During post maintenance testing, unexpected load oscillations of 150 kW were again experienced. The licensee replaced the EGM and started the engine to tune the newly installed governor. During tuning attempts, licensee personnel were unable to control load swings and replaced the newly installed EGM with a different EGM. The engine was again started to tune the governor. After about 1 minute, a couple of minor (about 100 kW) oscillations were observed followed by a large step increase (about 1000 kW) in load. While troubleshooting this large load increase, the licensee identified that a washer was not correctly located between the EGB terminal output shaft lever and the connected linkage arm. The washer was installed between the connecting bolt and the Heim end of the linkage shaft. The correct location was between the Heim end and the governor output shaft lever. It was further determined that with this washer in the incorrect location, the linkage arm Heim end could contact the output shaft lever during EGB output shaft repositioning while moving the fuel racks. The licensee corrected the condition and no additional problems were identified during post maintenance testing activities. Maintenance of the fuel rack was historically treated as a "skill of the craft" evolution and there had been little attempt to maintain the vendor recommended fuel rack configuration. Therefore, it was unknown how long this problem previously existed. The ensuing troubleshooting efforts prevented completion of the planned maintenance and testing activities within the 72-hour allowed outage time and the licensee shut down Unit 2 in accordance with TSs.

The licensee’s root cause evaluation determined that the most probable cause for this event was an inadequate configuration control process which led to mechanical binding of the Unit 2 CD EDG governor linkage. This condition was further complicated by the lack of expertise in maintaining and diagnosing the governor system. The incorrect assembly of the linkage at the governor output shaft lever resulted in the binding of the connection, preventing normal diesel speed and load control response. This was a different root cause than the root cause determined for the November 2002 event; however, it was apparent that the condition existed and contributed to that event as well. The licensee also identified the following causal factors in their root cause investigation:

- The level of knowledge necessary to troubleshoot and tune the EDG governor was not adequate to identify problems, test, and maintain the EDGs.
- Training had not been provided to engineering or maintenance personnel to understand the integrated operation of the EDG governor modules.
- Procedures to test, install, tune, troubleshoot, and maintain the EDG governor had not always been available.
- The station had over-relied on the vendor to troubleshoot and repair the EDG governor.
- The station had not ensured that equipment that had aged to the point where reliability of the equipment had been significantly impacted was upgraded to current industry standards.
- The configuration control, procurement, and receipt inspection processes had not been effective in maintaining the EDG governor in its current configuration.
- Evaluation of previous EDG oscillation events failed to identify or correct the extent of condition involving aging components and configuration control.

The licensee evaluated the load oscillations discussed above and documented in CR 03025002, “While at Full Load (3500 kW) Unit 2 CD EDG Experienced 150 kW Load Swings.” That evaluation concluded that although performance of the EDG was degraded, the EDG would have been able to perform its safety function during a design basis accident and was operable.

Analysis

The inspectors determined that the licensee's failure to ensure that corrective actions were taken to preclude repetition of unexpected load oscillations on the Unit 2 CD EDG was a licensee performance deficiency warranting a significance evaluation. The Mitigating Systems cornerstone was impacted by this performance deficiency. The inspectors also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution.

The inspectors concluded that the finding had more than minor risk significance in accordance with Inspection Manual Chapter 0612, “Power Reactor Inspection Reports,”

Appendix B, “Issue Disposition Screening,” because the Unit 2 CD EDG governor control failures and resulting load oscillations were associated with the Configuration Control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences since the EDG was taken out of service to correct the problem.

For the November 5, 2002, EDG unavailability period, in accordance with Inspection Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” a Phase 1 SDP was initiated. In accordance with the “SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones,” the inspectors determined that since Unit 2 was not shut down prior to exceeding the Allowed Outage Time for the Unit 2 CD EDG, the finding represented an actual loss of safety function of a single train of safety-related equipment for greater than its TS Allowed Outage Time and a Phase 2 SDP evaluation was warranted. The inspectors utilized the “Loss of Offsite Power (LOOP)” Phase 2 SDP Worksheet and solved only those sequences that involved the EDG with a duration of 3-30 days, since the total unavailability of the Unit 2 CD EDG was only about 85 hours. The inspectors also utilized the “Dual Unit LOOP With Loss of Emergency AC Bus Train or the Associated EDG (LEAC)” SDP worksheet and increased the initiating event frequency by 2 orders of magnitude to account for the unavailable EDG and solved all worksheet sequences. Based on the results of both SDP worksheets, the inspectors determined that the finding was potentially of low to moderate safety significance (White). The regional Senior Reactor Analyst (SRA) reviewed these results and determined that the SDP worksheets were potentially conservative since the initial results represented an unavailable EDG for 30 days as opposed to the 3.6 days of actual unavailability.

The SRA performed a Phase 3 risk assessment using the risk achievement worth (RAW) value for the Unit 2 CD EDG failing to run and an unavailability duration of 86 hours. This calculation determined that the finding was of very low safety significance (Green). The SRA reviewed the licensee's risk evaluation for this same issue which was presented during the licensee's NOED request and determined that the NOED was granted, in part, due to the low safety significance of the extended unavailability and no net increase in core damage frequency.

For the January 23, 2003, EDG unavailability period, in accordance with Inspection Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” a Phase 1 SDP was initiated. In accordance with the “SDP Phase 1 Screening Worksheet for IE, MS, and B Cornerstones,” the inspectors determined that since Unit 2 was shut down prior to exceeding the TS Allowed Outage Time for the Unit 2 CD EDG, the finding did not represent an actual loss of safety function of a single safety-related train for greater than its TS Allowed Outage Time and the issue screened out as Green.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures,

malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to identify the cause and take corrective action to preclude repetitive Unit 2 CD EDG load oscillations, a condition adverse to quality. Specifically, following engine load oscillations on November 2, 2002, the licensee did not identify the cause and did not implement effective corrective actions to preclude recurrence of engine load oscillations on January 23, 2003. However, because of the very low safety significance and because this issue was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-316/03-06-01). The licensee entered this issue into their corrective action program as CR 03025002.

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 maintenance activities affecting the following equipment:

- Unit 1 West CCW System
- Unit 1 AB EDG
- Unit 1 and Unit 2 Circulating Water System and ESW System Intakes
- Valve 2-QMO-225

Maintenance associated with valve 2-QMO-225 was emergent work to correct damage to the valve's actuator which occurred during testing. The inspectors also reviewed the licensee's implementation of a new procedure to assess and manage risk associated with seasonal and conditional vulnerability of the circulating water system and ESW system intakes, following a fish intrusion event that significantly impacted the function of those systems.

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.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following 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 returned the affected equipment to an operable status.

- CR 03022022 — Auxiliary Feedwater Flow Retention Setpoint May Not Appropriately Account for the Emergency Leakoff Flow
- CR 03073001 — 1-PP-4 Turbine Driven Auxiliary Feedwater Pump Outboard Pump Shaft Seal Is Degraded
- CR 03114044 — Fish Intrusion Event Impact on Operability of EDGs
- CR 03115014 — While Attempting to Flush the 2AB EDG Air Aftercoolers it Was Discovered that 2-WRV-726 and 2-WRV-728 Would Not Fully Stroke When Control Air Was Removed from the Valve
- CR 03025002 — While at Full Load (3500 kW) Unit 2 CD EDG Experienced 150 kW Load Swings

The inspectors also reviewed the licensee’s justification for not correcting existing degraded and nonconforming conditions during refueling outage U2C14 consistent with the timeliness guidance contained in Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1.

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 workarounds (OWAs) listed below to identify any potential affect on the functionality of mitigating systems or on the operators’ response to initiating events:

- Unit 2 Main Steam Isolation Valve Closures Following Reactor Trips
- Unit 2 Control Rod H-8 Does Not Indicate Fully Inserted Following Reactor Trips

The first issue was reviewed to understand the conditions contributing to excessive plant cooldowns following reactor trips that have resulted in operators closing main steam isolation valves.

The second issue was reviewed because separate criteria for verifying control rod position H-8 have been incorporated into the reactor trip emergency operating procedure to address a long-standing indication problem. 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 verified that operator workaround issues were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the engineering analyses, modification documents, and design change information associated with the following permanent plant modifications:

- 01-MOD-35447-R0, "Repair/Replace the CCW Heat Exchanger (1-HE-15E and W) Channel Head Divider Plate," Revision 0

- 02-LDCP-5452, "Rewire Unit 2 Control Group and Water System Indication (WSI) Cabinet 24 Volt Power Supplies," Revision 0

The first modification replaced the channel head divider plate on the ESW side of the CCW heat exchangers. The licensee had previously identified bowed divider plates and cracked attachment welds for the divider plates. During the fish intrusion event on

April 24, 2003, the divider plate on the Unit 1 West CCW heat exchanger failed. The licensee subsequently replaced the divider plates in all four CCW heat exchangers.

The second modification replaced power supplies in the control group and WSI cabinets, incorporated an alarm function for a single failed power supply, and provided the means to replace a failed power supply without de-energizing the entire cabinet.

The inspectors evaluated the implementation of these design changes and verified the following:

- the compatibility, functional properties, environmental qualification, seismic qualification, and classification of materials and replacement components were acceptable;
- the affected operating procedures and training were identified and necessary changes were completed;
- pressure boundary integrity was not compromised;
- the implementation of the modifications did not impair key safety functions;
- no unintended system interactions occurred;
- the system performance characteristics affected by the modification continued to meet the design basis; and
- the modification design assumptions were appropriate.

Completed activities associated with the implementation of the modifications were also inspected and the inspectors discussed the modifications with the responsible engineering, maintenance, performance verification, and operations staff. In addition, the inspectors reviewed the applicable sections of the TSs, Updated Final Safety Analysis Report (UFSAR), and 10 CFR 50.59 safety evaluations associated with the design change packages.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Unit 1 West CCW Train Motor-Operated Valve Maintenance
- Unit 2 CD EDG Governor Replacements
- Unit 2 West Charging Pump Overhaul
- Unit 2 CD EDG Overhaul

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 verifies 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 Forced Outage

a. Inspection Scope

On April 24, 2003, the licensee entered a Unit 1 forced outage period following a manual reactor trip initiated in response to a main feedwater pump trip, lowering condenser vacuum, and indications of traveling water screen fouling which was caused by a large influx of fish which damaged the traveling water screens. The licensee entered Mode 5 (Cold Shutdown) to clean, inspect, and repair affected equipment.

The inspectors evaluated the conduct of forced outage activities to assess the 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 and reviewed outage work activities to ensure that correct system lineups were maintained for key mitigating systems. Major outage activities evaluated included the licensee's control of systems, structures, and components (SSCs) which could cause unexpected reactivity changes; 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 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 the following:

- verification that reactor coolant system (RCS) boundary leakage requirements were met prior to entry into Mode 4 (Hot Shutdown) and subsequent operational mode changes;
- verification that containment integrity was established prior to entry into Mode 4;
- inspection of the Containment Building to assess material condition and search for loose debris which could be transported to the containment recirculation sumps and cause restriction of flow to the emergency core cooling system (ECCS) pump suctions during accident conditions.

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

b. Findings

No findings of significance were identified.

.2 Unit 2 Refueling Outage U2C14

a. Inspection Scope

On April 24, 2003, the licensee entered a forced outage on Unit 2 following a manual reactor trip initiated in response to lowering condenser vacuum and traveling water screen fouling which was caused by a large influx of fish which damaged the traveling water screens. The licensee entered Mode 5 to clean, inspect, and repair affected equipment. The licensee subsequently entered a refueling outage period, which had been scheduled to begin on May 5, 2003.

The inspectors evaluated the performance of Unit 2 refueling outage activities and assessed the licensee's control of plant configuration and shutdown risk management. 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 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 the following:

- 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 TSs and was consistent with the design basis; and
- observation and review of reactor physics testing to verify that core operating limit parameters were consistent with the core design so the fuel cladding barrier would not be challenged.

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.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed portions of the following 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-OHP-5030-050-001, "Main Turbine and Feed Pump Turbine Valve Functional Checks"
- 01-OHP-4030-STP-016, "Reactor Coolant System Leak Test"
- 02-OHP-4030-232-217A, "DG2CD Load Sequence Testing and ESF [Engineered Safety Features] Testing"
- 02-OHP-4030-STP-017T, "Turbine Driven Auxiliary Feedwater System Test"
- 12-EHP-4030-056-218, "Automatic Operation of Auxiliary Feedwater Pumps"
- 12-IHP-5030-EMP-001, "Limitorque Valve Operator Preventive Maintenance"

The inspectors reviewed the test methodology and test results in order 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

No findings of significance were identified.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modifications and verified that the installations were consistent with design modification documents and that the modifications did not adversely impact system operability or availability:

- 1-TM-03-05-R0, "Heater Drain Pump Trip on Unit 1 Turbine Trip"
- 2-TM-03-22-R0, "Temporary Power Cable from 600 Volt AC Motor Control Center Starter 2-ABV-D-5C to the Unit 2 East Charging Pump Mini-flow Shutoff Valve (2-QMO-225) Actuator Motor"
- 2-TM-03-45-R0, "Removal of CCW Flow to 2-CPN-2 Inner Cooling Coil"
- 12-TM-01-14-R0, "Turbine Room Sump Emergency Overflow Piping Repair"

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 and operations department personnel and reviewed the design modification documents and 10 CFR 50.59 evaluations against the applicable portions of the UFSAR.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed two announced emergency preparedness drills that were conducted in the control room simulator and emergency response facilities on April 8, 2003, and June 17, 2003. The inspection focused on the evaluation of the licensee's classifications, notifications, and protective action recommendations for the simulated events. The inspectors also evaluated the licensee's conduct of the drill, including the critique of performance to identify weaknesses and deficiencies.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

20S1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiological Boundary Verification

a. Inspection Scope

The inspectors performed walkdowns of selected radiologically controlled areas to verify the adequacy of radiological boundaries and postings. The inspector reviewed the administrative controls specified in radiation work permits (RWPs); the radiological postings and physical barriers for access to these areas; and assessed worker adherence to these controls through direct observation. Specifically, the inspector walked down several high and locked high radiation areas in the Auxiliary Building to verify that these areas were properly posted and controlled in accordance with 10 CFR Part 20 and TSs. Additionally, the inspector accompanied radiation protection and operations staff during Mode 3 post-trip walkdowns of the Unit 1 Containment Building to evaluate the radiological controls for locked and very high radiation area access, and to verify worker adherence to area entry and egress requirements.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning and Controls (71121.02)

.1 Radiation Dose Goals and Trending

a. Inspection Scope

The inspectors reviewed the licensee's historical refueling outage exposure data to identify job specific exposure challenges and to determine prior performance compared to the rest of the industry. The inspectors reviewed the ALARA dose forecasting methods and current projections for radiological jobs expected to exceed 3 rem and planned during the May 2003, Unit 2 refueling outage (U2C14). The review was performed to determine if adequate bases for job dose estimates existed, and to determine if prior outage experiences and job scope and resource estimates were accurate and used adequately to establish dose projections. The inspectors also discussed with the ALARA staff their plans for daily outage exposure tracking to determine if the licensee could identify exposure performance problems in a timely manner to allow for prompt remedial actions.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors reviewed the licensee's procedures that governed radiologically significant work, ALARA planning and RWP development, and evaluated several U2C14 ALARA plans and work packages to verify consistency with procedures and to assess their overall adequacy relative to prior licensee practices and industry standards. Specifically, the inspectors selected the following outage jobs that were projected to accrue exposure of 3 rem or greater, and assessed the adequacy of the radiological controls and the work planning developed for each:

- Control Rod Drive Mechanism Head Inspections (RWP 032106)
- Scaffold Erection/Removal in the Auxiliary Building and Plant Restricted Areas (RWP 032126)
- Install, Modify and Remove Containment Scaffolding (RWP 032142)
- Reactor Coolant Pump Seal Maintenance Activities (RWP 032151)
- Design Change 5194 - Steam Generator Platform Installation (RWP 032190)
- Design Change 5326 - Permanent Shielding in Containment (RWP 032191)

The inspector reviewed the RWP and the ALARA plan developed for each job, and assessed the radiological engineering controls and other dose mitigation techniques developed to verify that the plans were completed in compliance with procedures, included appropriate controls to reduce dose, and were sufficiently comprehensive as dictated by the radiological hazards. These documents were also reviewed to determine if job history files, lessons learned from past outages, industry operating experience, and the use of mockups were considered in the planning process and were integrated into each work package. Additionally, total effective dose equivalent (TEDE) ALARA evaluations completed for these activities were assessed to ensure that the use of respiratory protection equipment or engineering controls in lieu of respirators was justified. The inspector discussed work planning with ALARA staff and work craft supervisors to determine if adequate interface between contractors, station work groups, and radiation protection (RP) staff occurred during job planning. Additionally, the inspector reviewed the RP staff's assessment and contingency planning for potential transuranic (TRU) nuclides to verify that the licensee developed adequate protocols to identify and control alpha emitting materials.

b. Findings

No findings of significance were identified.

.3 Radiological Support for Mode 3 Walkdowns

a. Inspection Scope

The inspector attended the pre-job radiological briefing and accompanied licensee staff during Mode 3 leak inspections in the Unit 1 Containment Building following a unit trip on April 24, 2003. The inspector assessed the RP staff support for the walkdowns, evaluated the radiological controls and the communications used to reduce dose, and worker adherence to the RWP and briefing instructions.

b. Findings

No findings of significance were identified.

.4 Verification of Exposure Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the methodology and assumptions used by the ALARA group to develop U2C14 dose estimates. The inspectors reviewed job dose history files and dose reduction plans for radiologically significant jobs to determine if previous problems had been adequately addressed to reduce dose. The inspectors evaluated these work activities to determine whether the licensee identified those factors that previously contributed to additional dose and/or inaccurate dose estimates, and implemented mechanisms to achieve dose savings.

b. Findings

No findings of significance were identified.

.5 Source Term Reduction and Control

a. Inspection Scope

The inspectors reviewed selected exposure reduction initiatives planned for the outage such as flushing, installation of temporary shielding and the licensee's plans for induced crud burst water chemistry initiatives to determine their impact on source term. The inspector also reviewed plans for post crud burst surveys and area posting and access controls to determine if those plans addressed vulnerabilities and previous problems experienced by the licensee. Additionally, the licensee's long range plans for source term reduction were reviewed to determine if exposure reduction initiatives were developed and being pursued by station management.

b. Findings

No findings of significance were identified.

.6 Monitoring of Declared Pregnant Women and Dose to the Embryo/Fetus

a. Inspection Scope

The inspectors reviewed the licensee's monitoring methods and procedures, exposure controls and the information provided to declared pregnant women to determine if an adequate program had been implemented to limit embryo/fetal dose. The inspector also reviewed the pregnancy declaration and radiation exposure results for several individuals that declared their pregnancy to the licensee within the 16 months preceding the inspection to verify compliance with the requirements of 10 CFR 20.1208 and 10 CFR 20.2106.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Initiating Events, Barrier Integrity

.1 Unplanned Scrams per 7000 Critical Hours and Unplanned Scrams with Loss of Normal Heat Removal

a. Inspection Scope

The inspectors verified the Unplanned Scrams per 7000 Critical Hours and the Unplanned Scrams with Loss of Normal Heat Removal performance indicators for both units. The inspectors reviewed Licensee Event Reports (LERs) from July 2002 through March 2003, determined the number of scrams that occurred, evaluated each of the scrams against the performance indicator definitions, and verified the licensee's calculation of critical hours for both units.

b. Findings

No findings of significance were identified.

The inspectors identified an Unresolved Item (URI) related to three Unit 2 reactor trips that were not reported for the Unplanned Scrams with Loss of Normal Heat Removal performance indicator. Shortly after each of these trips, operators manually isolated the main steam lines to stabilize RCS temperature.

Discussion

As a result of excessive RCS cooldown following Unit 2 reactor trips, operators had frequently taken action to manually isolate the main steam lines to arrest the cooldown. On these occasions, closing the main steam isolation valves resulted in the loss of the normal heat removal path to the main condenser. Plant operators subsequently maintained RCS temperature using the steam generator atmospheric dump valves. There were four Unit 2 reactor trips on October 7, 2001, May 12, 2002, July 22, 2002, and February 5, 2003 where operators manually isolated the main steam lines to stabilize RCS temperature. The licensee reported only the May 2002 reactor trip for the Unplanned Scrams with Loss of Normal Heat Removal performance indicator. This reactor trip was reported because the licensee considered the main condenser to be unavailable without an auxiliary steam supply to maintain condenser vacuum; not because the main steam isolation valves were closed shortly after the trip. The other three reactor trips were not reported for the performance indicator because the licensee staff believed that the exception in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2, that permitted operator action to control the reactor cooldown rate was applicable.

Because of the excessive RCS cooldown that occurred following these reactor trips, operators closed the main steam isolation valves based on their training and procedure guidance in response to the undesired plant temperature response. For this reason, the inspectors believed that operator actions to close the main steam isolation valves and maintain them closed was taken to mitigate an off-normal condition. The licensee's reactor trip response procedure included an "Action/Expected Response" that RCS temperature following a trip would be stable at or trending to the no-load average temperature value of 547°F. If that expected response was not obtained, operators were directed to take actions to mitigate or correct the condition. The "Response Not Obtained" column of the procedure directed operators to discontinue dumping steam and verify that steam generator blowdown was isolated. If cooldown continued, operators were then directed to control total feedwater flow; and if cooldown continued, operators were directed to close all main steam isolation valves and other steam valves.

Two inspector feedback forms and two licensee Frequently Asked Question (FAQ) forms were previously submitted to address interpretation questions associated with the October 2001 and July 2002 reactor trips. Resolution of the FAQ for the October 2001 reactor trip was pending. Final resolution of the July 2002 reactor trip FAQ was approved by the NRC staff during a May 22, 2003, public meeting. The conclusion was that the trip should be counted in the performance indicator as an Unplanned Scram with Loss of Normal Heat Removal.

The performance indicator data submital for the first quarter of 2003 included a comment in the data report addressing the two FAQs submitted for the October 2001 and July 2002 reactor trips. The comment also referenced the February 2003 reactor trip. The inspectors believed that this trip should also be counted in the performance indicator as an Unplanned Scram with Loss of Normal Heat Removal and have submitted a feedback form to resolve the question. This issue is an Unresolved Item (URI) pending final resolution of open questions regarding the interpretation of the performance indicator guidance (URI 50-316/03-06-02).

.2 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors verified the Unplanned Power Changes per 7000 Critical Hours performance indicator for both units. The inspectors reviewed power history data from July 2002 to March 2003, determined the number of power changes that exceeded 20 percent, evaluated each of those power changes against the performance indicator definition, and verified the licensee's calculation of critical hours for both units.

b. Findings

No findings of significance were identified.

.3 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors reviewed the dose equivalent iodine calculation procedure, the RCS sampling procedure, and interviewed members of the licensee's chemistry staff involved in the determination and verification of RCS specific activity. The inspectors selectively reviewed the Unit 1 and Unit 2 chemistry sample analysis results for dose equivalent iodine for December 2002 through April 2003. These reviews were performed to verify that the licensee adequately determined dose equivalent iodine values, and to verify adherence to station procedures and to the guidance contained in NEI 99-02 relative to assessing and reporting the RCS specific activity performance indicator. Additionally, the inspectors observed a chemistry technician collect an RCS sample to verify that the sample was collected properly, and discussed with the chemistry staff the method used to calculate dose equivalent iodine to verify this method was adequate.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Problem Identification and Resolution Findings

Section 1R12 of this report describes a finding in which the licensee failed to take effective corrective actions to prevent repetitive load oscillations on the Unit 2 CD EDG.

Section 4OA3.1 of this report describes a finding in which the licensee failed to assure that prompt corrective actions were taken to address age-related failures of reactor control instrumentation power supplies to prevent repetition of power supply failures.

.2 Incomplete Corrective Actions for Redundant Power Supply Failures

a. Inspection Scope

Following the failure of redundant reactor control instrumentation power supplies and a Unit 2 trip on May 12, 2002, the licensee failed to effectively implement a corrective action to perform weekly verifications of the "power available" status lights connected with each of the power supplies to identify if a power supply had failed. This weekly verification was an interim corrective action pending the installation of a modification to provide annunciation for the loss of a single power supply. The inspectors previously documented a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI (NCV 50-316/02-09-02) for this issue. The inspectors reviewed the root cause evaluation for CR 02325058, "Weekly Recurring Tasks to Walkdown Taylor Mod-30 Power Supplies - No Documented Performance of Walkdown Since September 30, 2002," associated with this issue.

The inspectors verified the following attributes during their review of the licensee's corrective actions for the above CR and several 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 site personnel.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 50-316/2003-002-00: "Unit 2 Trip Due to Instrument Rack 24-Volt DC Power Supply Failure."

a. Inspection Scope

On February 5, 2003, an automatic reactor trip of Unit 2 occurred due to the failure of redundant 24-volt direct current (DC) power supplies in reactor control instrumentation cabinet 2-PS-CGC-21. The failure of both power supplies caused the number 23 steam generator feedwater regulating valve to close. Unit 2 subsequently tripped due to a feedwater-flow/steam-flow mismatch coincident with low steam generator water level. The inspectors reviewed the circumstances associated with this event, and a similar Unit 2 reactor trip on May 12, 2002, including the root cause evaluations and corrective actions.

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," when the licensee failed to take effective corrective actions to address age-related failures of reactor control instrumentation power supplies to prevent repetition of power supply failures.

Discussion

On May 12, 2002, an automatic reactor trip of Unit 2 occurred due to the failure of redundant 24-volt DC power supplies in reactor control instrumentation cabinet 2-PS-CGC-16. The failure of both power supplies caused the number 21 steam generator feedwater regulating valve to close. Unit 2 subsequently tripped on low steam generator water level coincident with low feedwater flow. The licensee reported this event in LER 50-316/2002-005-00. The inspectors previously reviewed the licensee's root cause evaluation for this event and concluded that the failure to assure that prompt corrective actions were taken to address age-related failures of reactor control instrumentation power supplies to prevent the repetition of power supply failures was a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI (NCV 50-316/02-09-01).

On February 5, 2003, another automatic reactor trip of Unit 2 occurred due to the failure of redundant 24-volt DC power supplies in reactor control instrumentation cabinet 2-PS-CGC-21. The inspectors noted that the licensee had not replaced the aged 24-volt DC control group power supplies following the Unit 2 reactor trip in May 2002. Only the failed 24-volt DC power supplies in reactor control instrumentation cabinets 2-PS-CGC-16 and 2-PS-CGC-19 had been replaced. Following the Unit 2 reactor trip on February 5, 2003, the licensee took corrective actions to replace all of the Unit 2 control group power supplies.

Each reactor control instrumentation cabinet contained two separate power supplies (originally Lambda Model LRS-57-24 or LMS-9120). The two power supplies were interconnected through auctioneering diodes, such that the cabinet remained energized in the event of the failure of one of the power supplies. The cabinets provide indication and control functions for various plant systems including steam generator feedwater control, automatic steam generator power operated relief valve (PORV) control, automatic steam dump control, RCS volume control tank automatic make-up, automatic switch-over of the charging pump suction to the refueling water storage tank on low-low volume control tank level, automatic pressurizer pressure control using spray valves and heaters, automatic pressurizer level control, and automatic pressurizer PORV controls. Detection of a single power supply failure was inhibited because there was no annunciation on the loss of a single power supply. There were "power available" status lights connected with each of the power supplies located inside the normally closed cabinet doors and the licensee performed weekly verification of the status lights. This weekly verification was a corrective action following the Unit 2 reactor trip in May 2002, pending the installation of a modification to provide annunciation for the loss of a single power supply. The licensee had verified that both power supply status lights were lit 2 days prior to the Unit 2 reactor trip on February 5, 2003.

The reactor control instrumentation cabinet power supplies were originally installed in both units in 1994 as part of a modification to replace obsolete equipment. In 1999 and 2000, several of these power supplies failed and were sent to a vendor for repair. Repair reports generated by the vendor identified the existence of internal components that were much older than expected. Following the Unit 2 reactor trip in May 2002, the two failed power supplies from 2-PS-CGC-16 and several other failed 24-volt DC power supplies were sent to the vendor for detailed analysis. All of the failures were determined to be age-related. In all cases, capacitors with date codes as early as 1989 were found. Therefore, these power supplies were already several years old when they were first installed and energized.

The licensee recognized in August 2001 that there had been a significant number of DC power supply failures during the 24-month period prior to August 2001. A total of 20 power supply failures were documented in CR 01236037, including 6 reactor control instrumentation power supply failures, stating that the failures should be investigated for a common cause. Other power supply failures were in nuclear instrumentation, radiation monitoring instrumentation, reactor protection instrumentation, rod control/rod position indication, steam generator PORV indication, reactor coolant pump vibration monitoring instrumentation, and main generator hydrogen and carbon dioxide purity monitoring. The inspectors noted that the licensee did not complete the evaluation of CR 01236037 until after the May 2002, Unit 2 reactor trip. This was the basis for the finding referenced above and associated with the May 2002 reactor trip. The licensee concluded that the apparent cause for the power supply failures was the degradation of capacitors in all but four cases. Two of the remaining failures were attributed to the method by which the power supplies were placed back in service, and two other failures were attributed to poor maintenance practices.

The inspectors also determined that the licensee did not plan to replace the Unit 2 reactor control instrumentation power supplies until a May 2003 refueling outage. Although a forced outage work activity was created in the Fall of 2002, the licensee did not plan and include power supply replacements in a subsequent forced outage in January 2003. The inspectors noted that there were forced outages in July 2002 and January 2003, during which time the licensee could have replaced these power supplies. The availability of replacement power supplies was not a significant issue since the licensee was able to obtain sufficient power supply replacements on relatively short notice during the Unit 1 refueling outage in May 2002. According to the licensee's root cause evaluation, the decision to defer power supply replacements until the refueling outage was made without management's full knowledge or appreciation for the extent of power supply internal component age degradation. Considering that additional power supply failures in the reactor control instrumentation cabinets could result in a reactor trip and that plant personnel were aware of the power supply history based on CR 01236037 and the apparent cause evaluation for the May 2002 reactor trip, the inspectors concluded that this decision increased the likelihood an initiating event (i.e., a reactor trip).

<u>Analysis</u>

The inspectors determined that the licensee's failure to assure that corrective actions were taken to preclude repetitive age-related failures of reactor control instrumentation power supplies was a licensee performance deficiency warranting a significance evaluation. The Initiating Events cornerstone was impacted by this performance deficiency. The inspectors also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution.

The inspectors concluded that the finding had more than minor risk significance in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," because the failure to assure that corrective actions were taken to preclude repetitive age-related failures of reactor control instrumentation power supplies could, if left uncorrected, result in additional reactor trips and challenge safety-related equipment.

In accordance with Inspection Manual Chapter 0609, "Significance Determination Process [SDP]," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," a Phase 1 SDP was initiated to address the finding. That review determined that the finding affected the Initiating Events cornerstone since the likelihood of a reactor trip was increased as a result of the event. Therefore, in accordance with the “SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones,” since the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, a Phase 2 SDP analysis was warranted.

Using the risk-informed D. C. Cook Phase 2 worksheets, and assuming that: (1) the likelihood for transients, including those involving a loss of the primary conversion system, was increased by an order of magnitude using Usage Rule 1.2 of IMC 0609, Appendix A, Attachment 2; (2) the initiating event likelihood was greater than 30 days since the vulnerability existed since the May 2002 reactor trip; and (3) credit for recovery actions was not necessary because full mitigation credit was assumed, the Phase 2 SDP analysis determined that the finding was of very low safety significance (Green).

<u>Enforcement</u>

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to take effective corrective actions to address age-related failures of reactor control instrumentation power supplies to prevent the repetition of power supply failures, a significant condition adverse to quality. Specifically, following the Unit 2 reactor trip on May 12, 2002, the licensee did not replace reactor control instrumentation power supplies susceptible to near term age-related failures. In addition, there were forced outages in July 2002 and January 2003, during which time the licensee could have replaced these power supplies. Consequently, two redundant reactor control instrumentation power supplies failed in reactor control instrumentation cabinet 2-PS-CGC-21 on February 5, 2003, which resulted in a reactor trip and challenged the function of safety-related equipment. However, because of the very low safety significance, and because this issue was entered into the licensee’s corrective action program, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-316/03-06-03). The licensee entered this issue into their corrective action program as CR 03036056 and CR 03083050. This LER is closed.

.2 <u>(Closed) LER 50-316/2002-007-00</u>: "Technical Specification 3.8.1.1 Allowed Outage Time Exceeded." On November 5, 2002, the Unit 2 CD EDG experienced unexpected load oscillations during surveillance testing. Numerous equipment failures and necessary troubleshooting prevented completion of corrective maintenance and testing activities within the TS 3.8.1.1.b 72-hour allowed outage time. The licensee requested and received enforcement discretion for an additional 72 hours to accomplish restoration of the engine to preclude a required unit shutdown. The NRC staff concluded that there was no net increase in risk associated with extending the allowed outage time from 72 hours to a total of 144 hours. The inspectors reviewed the event and the licensee's request for enforcement discretion and determined that enforcement discretion was necessitated, in part, by incorrect assembly of the linkage at the governor output shaft lever resulting in binding of the connection, preventing normal EDG speed and load control response. The inspectors also noted that the evaluation of previous EDG oscillation events failed to identify or correct the extent of condition involving aging components and configuration control. As discussed in Sections 1R12 and 4OA5.1 of this report, the inspectors concluded that this failure was a finding of very low safety significance and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." The inspectors identified no other issues of significance during this review. This LER is closed.

.3 (Closed) LER 50-316/2003-001-00: "Unit 2 Shutdown in Accordance with TS 3.8.1.1, A.C. Sources, Action b." The event described in this LER was discussed in Section 1R12 of this report. The inspectors determined that the licensee's failure to assure that corrective actions were taken to preclude the repetition of load swings on the Unit 2 CD EDG was a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." The licensee reported completion of a TS required plant shutdown in accordance with 10 CFR 50.73(a)(2)(i)(A). This LER is closed.

.4 Dual Unit Reactor Trip Due to Fish Intrusion in Forebay

a. Inspection Scope

On April 24, 2003, operators manually tripped both units in response to lowering condenser vacuum and traveling water screen fouling which was caused by a large influx of fish which damaged the traveling water screens. An Alert was declared due to degraded essential service water (ESW) conditions and subsequently exited after safety-related supplies were reliably restored. The licensee performed a reactor startup and synchronized Unit 1 to the grid on May 28, 2003. Following completion of a planned refueling outage, the licensee performed a reactor startup and synchronized Unit 2 to the grid on June 20, 2003.

The inspectors assessed the licensee's emergency response organization and control room operator performance during the event. The inspectors evaluated the degraded plant conditions and the licensee's actions to mitigate the impact on affected plant safety systems and recover from the event. The inspectors also confirmed that the licensee properly classified the event and made timely notifications to the NRC and local officials.

b. Findings

No findings of significance were identified.

.5 (Closed) LER 50-315/1999-023-01: "Retraction of LER 50-315/1999-023-00," Supplement 1. The licensee submitted Supplement 1 to LER 50-315/1999-023-00 to provide the basis for retracting the original LER. Following Generic Letter 93-08 recommendations, the licensee had removed the Engineered Safety Feature (ESF) response time requirements from the TSs and incorporated these in UFSAR Table 7.2-7, "Engineered Safety Features Response Times." In 1997, the licensee again revised the UFSAR and added an amended note to Table 7.2-7 that used the

TS generic definition of the ESF response time. This wording led to an alternate interpretation about existing ESF response time testing fulfilling UFSAR requirements and led to issuing the initial LER. The licensee later determined that the initial investigation was deficient and had not identified that multiple tests fulfilled the design basis function. The surveillance test requirement was effectively fulfilled by two tests. The first verified the response time from actuation of the channel sensor to ESW pump start (pump breaker closure) and the second verified stroke time by quarterly testing of the ESW pump discharge valve (breaker closure to valve open). The inspectors determined that the information provided in Supplement 1 to LER 50-315/1999-023-00 presented an acceptable basis for retraction. The initial review of the original LER was documented in NRC Inspection Report 50-315/99-033;50-316/99-033. This LER is closed.

4OA5 Other

.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,” 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 effective and reliable; (3) request information from all addressees concerning the Reactor Pressure Vessel (RPV) head and VHP nozzle inspection programs; and (4) require all 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 Accession Number ML030410402). The purpose of this order was to require specific inspections of the RPV head and associated penetration nozzles. The purpose of TI 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles,” was to support the review of licensees’ RPV head and VHP nozzle inspection activities required by NRC Order EA-03-009. This NRC review served to confirm that the licensee used procedures, equipment, and personnel that had been demonstrated to be effective in the detection and sizing of primary water stress corrosion cracking (PWSCC) in VHP nozzles, and detection of RPV head wastage. Additionally, this review served to promote information gathering to help the NRC identify and shape possible future regulatory positions, generic communications, and rulemaking. For these reasons, the inspectors’ documented observations, including minor violations of NRC requirements, and conclusions in response to the questions identified in TI 2515/150 associated with the licensee’s RPV head inspection activities.

The inspectors conducted the following activities 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 that have been demonstrated to be effective in the detection and sizing of PWSCC in VHP nozzles and detection of RPV head wastage:

- performed an independent direct visual examination of the head-to-nozzle interface for portions of 8 nozzles inside the Unit 2 containment;
- observed the licensee's remote visual examination of the RPV head for portions of 20 VHP nozzles;
- observed the videotaped dye penetrant (PT) examination of the RPV head vent J-groove weld which was conducted from under the RPV head;
- conducted interviews with the licensee's nondestructive examination personnel performing non-destructive examinations of the RPV head;
- observed acquisition and analysis of UT and eddy current (ET) data recorded from inspections of eight VHP nozzle locations;
- reviewed the head inspection procedures;
- reviewed the certification records for nondestructive examination (NDE) personnel who performed examinations of the RPV head;
- reviewed the procedures for identification and resolution of boric acid leakage from systems and components above the RPV head;
- reviewed the corrective actions which were implemented for boric acid leakage identified on components above the RPV head;
- reviewed the PT examination records for nozzles 43, 73, 74, 75, and the RPV head vent; and
- reviewed video records of PT examinations for nozzles 73 and 75.

The inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation documented in Design Information Transmittal (DIT) B-02726-00 and determined the following:

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

The inspectors also confirmed that the licensee performed the VHP nozzle susceptibility calculation using best estimate values for input parameters in accordance with requirements of NRC Order EA-03-009.

The inspectors reviewed procedures and interviewed personnel associated with performing examinations of components above the RPV head to identify evidence of leakage. Additionally, the inspectors reviewed corrective actions documented for potential leakage from components containing boric acid above the vessel head to evaluate conformance to NRC Order EA-03-009 associated with performing visual examinations to identify boric acid leakage from components above the RPV head.

The following activities were reviewed:

- flaw evaluations for VHP nozzles 59 and 64; and
- repair records, including post repair NDE records, for VHP nozzles 74 and 43.

The inspectors confirmed that the requirements of Sections III, IX, XI, and V of the ASME Code were met for Code repairs and NDE. In addition, the inspectors confirmed that for the flaw evaluations of VHP nozzles 59 and 64, the licensee applied crack growth rates consistent with NRC accepted flaw growth rates for PWSCC.

a. Observations

Summary

Although the licensee did not identify any leaking VHP nozzles, shallow crack indications located at the inside surface of VHP nozzles 43, 59, 64 and 74, which did not penetrate the nozzle wall, were identified. The licensee performed a repair on VHP nozzles 43 and 74 by removing a small amount of metal from the inside surface which contained the crack indications. For VHP nozzles 59 and 64, the licensee performed a flaw evaluation to accept these nozzles for continued service without repair.

During the visual examination of the RPV head, a number of VHP nozzle locations were categorized as indeterminate due to the quantity and quality of deposits in the head-to-nozzle region. At the conclusion of the inspection, the licensee implemented vacuum cleaning methods, and re-inspections to resolve the nozzles with indeterminate visual examinations.

Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/150, the inspectors 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.)

1.1. Upper Head Bare Metal Remote Visual Examination

Yes. The licensee conducted a remote visual examination of the top surface of the RPV head with knowledgeable staff members certified as VT-2 Level II examiners in accordance with programs meeting the American Society for Nondestructive Testing Recommended Practice SNT-TC-1A. Additionally, the licensee inspection staff had been trained on Electric Power Research Institute (EPRI) Report TR 1006296, “Visual Examination For Leakage Of PWR Reactor Head Penetrations,” Revision 2, issued in March 2003. This document contained a large number of color photographs of VHP nozzle leakage which had been identified during head inspections at PWR sites in the United States through the end of 2002. This report also contained pictures of leakage on the vessel heads at several plants from conoseals or other sources above the head.

1.2. Under Head Volumetric and Surface Examinations

Yes. The licensee's vendor conducted the underhead UT and ET examinations using personnel who were qualified in accordance with programs meeting the American Society for Nondestructive Testing Recommended Practice SNT-TC-1A or CP-189. These personnel typically had extensive experience with the UT and ET techniques which were being used.

The inspectors identified an isolated knowledge weakness in a vendor UT data analyst associated with the UT leakage path signature. The inspectors questioned a night shift vendor UT analyst responsible for analyzing UT data on the VHP nozzles. This analyst did not appear to be knowledgeable on the physical phenomena responsible for the leakage path signature in the UT data (e.g. that the loss of RPV head material causes a loss in the VHP nozzle-to-head interference fit, creating an air gap that is responsible for the change in UT backwall signal amplitude). This analyst incorrectly stated that the leak path UT signature was caused by the loss of metal (Inconel) from the VHP nozzle, instead of loss of RPV head material (carbon steel). The inspectors interviewed other vendor analysts including the lead analyst and did not identify a common weakness in understanding the physical representation of the leakage path UT signature. Therefore, the inspectors concluded that this example was an isolated case of a lack of effective training. The licensee's vendor re-reviewed the UT data completed by this analyst to confirm that no leakage paths had been misinterpreted.

1.3 Under Head PT Examinations

Yes. The licensee's vendor conducted the under head PT examinations using personnel who were qualified for PT in accordance with programs meeting the requirements of the American Society for Nondestructive Testing Recommended Practice SNT-TC-1A. The licensee's staff performing PT examinations had extensive experience with the manual solvent removable PT technique used.

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

2.1 Upper Head Bare Metal Remote Visual Examination

Yes. The licensee performed a demonstrated remote visual examination of the vessel head and penetration nozzles using three cameras mounted to a robotic crawler in accordance with procedure MRS-SSP-1483-AMP, "Rx Vessel Head Penetration Remote Visual Inspections For D. C. Cook, Unit 2." The licensee demonstrated the capability of the remote camera system to resolve color and 0.158-inch high lower case alphanumeric characters from 12 inches. However, the inspectors noted that this visual demonstration standard was less restrictive than an existing boric acid inspection procedure, 12 QHP-5050-NDE-027, "Visual Examination For Boric Acid And Condition Of Component Surfaces,“ which required resolution of smaller characters at greater distances. The licensee used this 12 inch distance as the maximum distance allowed for the examination of the nozzle interface area and similarly established a minimum distance for resolution of these alphanumeric characters.

The inspectors reviewed the videotape of the licensee's demonstration of color acuity and visual resolution and noted that it was consistent with procedure requirements. The inspectors performed a direct visual inspection of portions of eight head penetration nozzles viewable at the 200 degree head azimuth location through removed insulation at this location. Based on this examination, the inspectors noted that the remote picture quality appeared to provide superior inspection to that available based on a direct visual examination conducted from the access doors in the service structure. Overall, the inspectors considered the quality of the remote visual examination to be excellent based on the ability to resolve very small debris at the VHP nozzle-to-head interfaces.

2.2 Under Head Volumetric and Surface Examinations

The inspectors determined that none of the NDE procedures used to acquire or analyze NDE data for examinations of penetration nozzles below the vessel head contained or referenced acceptance criteria for any flaws identified. Each procedure contained appropriate recording criteria for determining and recording flaw sizes, but did not include identification of the root mean square sizing accuracy which had been documented during demonstration of the UT and ET techniques. The licensee stated that any flaws identified would be entered into the corrective action system and evaluated with appropriate criteria on a case-by-case basis.

The licensee was required to perform an assessment of leakage through the J-weld into the interference zone when performing UT examination of the nozzles in accordance with NRC Order EA-03-009. The licensee committed to perform this assessment in a letter dated March 26, 2003, which requested relaxation from some of the Order requirements. Specifically, the licensee stated that visual examination results in conjunction with evaluating the ultrasonic examination results would be used in their assessment to determine if leakage was occurring into the interference fit zone. The inspectors identified that UT analysis guidelines WDI-UT-013, "CRDM/ICI UT Analysis Guidelines," Revision 2, did not clearly define what to consider a leakage path in the interference fit zone. On May 15, 2003, the inspectors observations prompted the licensee to issue Field Change Notice 3 to Procedure WDI-UT-013, which provided pictorial C-scan backwall displays and additional instructions for analysts to use for identification of a leakage path UT signature in the interference fit zone. The licensee's vendor then re-reviewed all acquired UT data to ensure that a leakage path would be adequately identified and evaluated.

2.2.a Penetration Nozzles 10 Through 78

Yes. For the VHP nozzles with thermal sleeves, the licensee used a blade probe with UT transducers and ET coils in accordance with Procedures WDI-UT-010, "IntraSpect Ultrasonic Procedure For Inspection Of Rx Vessel Head Penetrations/Time Of Flight Ultrasonic, Longitudinal Wave & Shear Wave," and

WDI-ET-003, “IntraSpect Eddy Current Imaging Procedure For Inspection Of Reactor Vessel Head Penetrations.” The vendor used a PCS 23.5 type UT probe which contained transducers set up for time-of-flight-tip-diffraction (TOFT) and a X-wound ET coil. The licensee vendor provided a copy of the EPRI Materials Reliability Project Report Updated December 11, 2002, in which they had performed a demonstration of their PCS 24 probe. The vendor stated that they had actually used a PCS 23.5 probe during this demonstration which was performed on a mockup CRDM penetration nozzle with simulated cracks and electric discharge machined notches of known dimensions. In this demonstration, the licensee vendor was not completely successful in identification of flaws less than 10 percent through-wall from the outside surface. The vendor had also performed an internal demonstration (reference internal Wesdyne Leakage Detection Report, dated March of 2003) of the capability of the PCS 23.5 TOFT transducers to detect a simulated leakage path in the nozzle interference fit zone on a vendor mockup CRDM nozzle. This mockup contained a shrink fit steel collar with two axial notches and two holes which simulated the loss of interference fit observed during UT of head penetration nozzles with J-groove weld leakage and RPV head wastage.

The inspectors identified that the licensee had changed the UT equipment from the demonstrated equipment configuration. Specifically, the vendor changed the PCS 23.5 probe configuration to a two channel system with a high pass filter that affected both channels. This differed from the demonstrated single channel configuration without a high pass filter used on the EPRI demonstration mockup. The vendor had implemented this change to be able to use a single probe to perform both the inspection for flaws and monitoring of the UT backwall signal for indications of J-weld leakage. The vendor added the high pass filter to reduce unwanted low frequency energy from the preamplifier. The licensee vendor documented the equivalency of the revised PCS 23.5 blade probe configuration in internal technical reports WDI-TJ-008-03, “System Setup Testing Of Blade Probe For Multiple Inspection Sensitivities,” Revision 0; and WDI-TJ-007-03, “Installation of High Pass Filter To Improve Blade Probe Inspections,” Revision 0. In these reports, the licensee vendor concluded that with the filter in the system and operating in a two-channel mode, a valid calibration was achieved, the signal-to-noise ratio was improved, and the frequency response was identical compared to the system without a filter operating in a single channel mode. However, the inspectors noted that the vendor equivalency evaluation only compared signal-to-noise ratio for the channel associated with crack detection in the nozzle base material and not that used for leakage path detection. Therefore, the inspectors requested that the licensee provide a technical basis to confirm that the equipment change did not affect the demonstrated qualification for the IntraSpect channel used to identify a leakage path.

On May 17, 2003, the licensee vendor performed a demonstration of their internal CRDM leakage path mockup to confirm the ability of the PCS 23.5 dual channel probe with a high pass filter. The results of this demonstration and the vendor’s conclusions were documented in WesDyne report WDI-TJ-008-03, “System Setup Testing Of Blade Probe For Multiple Inspection Sensitivities,” Revision 1. The vendor documented that the high pass filter caused a 4 decibel reduction in sensitivity which was recovered with some increase in overall noise level. The vendor also concluded that the signal response from the grooves in the shrink fit sample were comparable with or without the high pass filter in line. The inspectors compared the PCS 23.5 probe C-scan data plots with and without the filter and noted that there was some degradation in resolution of the grooves and holes in the mockup. The inspectors noted that the smallest hole could not be identified and the narrow groove was more difficult to resolve with the high pass filter in the circuit. On May 21, 2003, the inspectors and NRC staff from the Office of Nuclear Reactor Regulation held a conference call with the licensee and vendor staff to discuss the sensitivity limitations of this UT system and whether these limitation impacted adequacy of the UT inspection. No concerns were identified.

For the 18 penetration nozzles without thermal sleeves, the licensee vendor used the 7010 open housing scanner with UT and ET probes in accordance with WDI-UT-010, "IntraSpect Ultrasonic Procedure For Inspection Of Rx Vessel Head Penetrations/Time Of Flight Ultrasonic, Longitudinal Wave & Shear Wave," and WDI-ET-003, "IntraSpect Eddy Current Imaging Procedure For Inspection Of Reactor Vessel Head Penetrations." The vendor's 7010 open housing scanner contained similar transducers to the PCS 23.5 blade probe supplemented with a 0 degree UT transducer used to identify the leakage path signature. The licensee vendor provided a copy of the EPRI Materials Reliability Project Report dated December 11, 2002, which documented a demonstration of the vendor's 7010 open housing scanner. The inspectors noted that in this demonstration the vendor did not identify all flaws less than 10 percent through wall. The inspectors noted that the demonstration which had been performed using the 0 degree transducer appeared to provide better resolution of simulated leakage paths than that demonstrated by the PCS 23.5 blade probe with TOFT transducers.

The licensee vendor performed UT analysis of data acquired in accordance with WDI-UT-013 "CRDM/ICI UT Analysis Guidelines." The licensee vendor performed ET analysis of data acquired in accordance with WDI-ET-004, "IntraSpect Eddy Current Analysis Guidelines Inspection Of Reactor Vessel Head Penetrations."

2.2.b Penetration Nozzles 1 Through 9

Yes. For the examination of center penetration nozzles 1-9, the licensee performed an ET with a cross-wound ET coil of the outer surface of the J-weld and nozzle surface using the "Grooveman" scanner probe in accordance with demonstrated Procedure WDI-ET-002, "IntraSpect Eddy Current Inspection Of J-Groove Welds in Vessel Head Penetrations." The vendor provided EPRI Materials Reliability Project Report dated December 11, 2002 and WDI-TJ-002-02, "Technical Justification For Eddy Current Of J-Groove Welds," which documented a demonstration of this ET probe on a J-weld mockup and provided a technical basis for the equipment used.

Yes. The licensee vendor used an ET gap scanner with dual pancake ET coils for examination of the inside surfaces of center penetration nozzles 1-9 in accordance with demonstrated Procedure WDI-ET-008, "IntraSpect Eddy Current Imaging Procedure For Inspection Of Rx Vessel Head Penetrations With Gap Scanner." The licensee vendor selected this method over UT techniques due to the potential for interference with thermal sleeve centering tabs. The ET probe had a narrower cross-section and was less susceptible to damage than the UT blade probe. The vendor initially provided EPRI TR-106260, "Demonstrations Of Inspection Technology For Alloy 600 CRDM Head Penetrations," dated October 1996, as the basis for demonstration of this technique. However, this document did not contain any specific descriptions of the ET equipment used, and the vendor subsequently confirmed that the equipment used in this demonstration was not the same as that used onsite.

The inspectors' questions prompted the licensee vendor to retrieve data and document a more recent demonstration of this equipment. Specifically, the vendor provided a letter from P. Lara (EPRI) to R. Hall (licensee), dated May 23, 2003, which documented the use of draft Revision 0 to Procedures WDI-ET-003 and WDI-ET-008 during a mockup demonstration at the vendor facility. The vendor had completed and documented data analysis for this demonstration on May 22, 2003. In the May 23, 2003 letter, the EPRI representative confirmed that the licensee vendor had successfully detected all the inside diameter initiated flaws in EPRI 97-01 mockup "A." The inspectors noted that this letter did not identify the equipment used on the mockup and requested additional documentation. The licensee provided a letter from B. Rassler (EPRI) to R. Hall (licensee), dated June 4, 2003, which confirmed that the vendor had used the same probes, equipment, and setup during this mockup demonstration as was used onsite.

The inspectors identified that WDI-ET-008 allowed the use of a cross-wound ET coil or dual pancake ET coils without any reference to coil size and spacing. Because the procedure lacked these details, the licensee could have used ET equipment which was not consistent with that demonstrated to be effective for the identification of cracks. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," required in part, that activities affecting quality shall be prescribed by documented instructions appropriate to the circumstances. Contrary to these requirements, Procedure WDI-ET-008, Revision 1, Change 1, failed to provide instructions that ensured that the technique/equipment used was qualified/demonstrated which was a violation of 10 CFR 50, Appendix B, Criterion V. The licensee issued Field Change Notice 2 to WDI-ET-008 to include coil size and spacing data, which corrected this issue and the licensee entered this issue into the corrective actions system (Esat 03143035 and 03143034). Because the licensee had used appropriately qualified equipment, and took appropriate corrective actions for the lack of specific documentation, the inspectors considered this violation of minor significance.

The licensee vendor performed ET analysis of data acquired in accordance with WDI-ET-004, "IntraSpect Eddy Current Analysis Guidelines Inspection Of Reactor Vessel Head Penetrations."

2.2.c <u>Head Vent Nozzle</u>

No. The inspectors identified that for the examination technique used on the head vent nozzle J-weld, the licensee did not have a documented demonstration to support the examination equipment used. For the examination of the head vent nozzle J-weld, the licensee vendor used an ET array probe in accordance with Procedure WDI-STD-101, "RVHI Vent Tube J-Weld Eddy Current Examination." The licensee vendor did not have a documented demonstration for the ET equipment used to identify cracking in the J-weld region of the head vent nozzle. The vendor probe contained an array of +Point ET coils and was manually rotated to scan the inner surface of the vessel head at the J-weld for the vessel head vent. For this technique, the licensee vendor considered the technique qualified based upon the ability to identify axial and circumferential notches in a calibration standard. Additionally, the licensee vendor stated that they were relying on this being a similar technique to those used to identify PWSCC cracking in SG tubes. However, the licensee vendor did not have a documented basis to confirm that the this ET technique was capable of detecting PWSCC cracking in VHP nozzles or J-welds.

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," required in part, that activities affecting quality shall be prescribed by documented instructions appropriate to the circumstances. Contrary to these requirements, Procedure WDI-STD-101, "RVHI Vent Tube J-Weld Eddy Current Examination," Revision 0, failed to provide instructions to ensure that the technique/equipment used was qualified/demonstrated which was a violation of 10 CFR 50, Appendix B, Criterion V. The licensee entered this issue into their corrective action system as Esat 03143036 and reported that they would not rely on the data obtained from this examination. Because the licensee did not rely on this examination data and no cracking was identified in the J-welds during follow up PT examinations, the inspectors considered the violation to be of only minor significance.

Because the ET array probe had not been specifically demonstrated by the vendor, the licensee elected to perform a solvent removable manual PT examination of the J-groove weld on the head vend nozzle in accordance with Procedure 12-QHP-5050-NDE-001, "Liquid Penetrant Examinations For Nuclear And Non-Nuclear Welds And Components." This procedure met the ASME Code requirements of the 1989 Edition of Section V and XI and applied the flaw acceptance criteria from the 1983 Edition, Summer 1984 Addenda of Section III.

Yes. For the examination of the internal surfaces of the head vent nozzle J-weld, the licensee was relying on the vendor X-wound ET coil examination in accordance with demonstrated Procedure WDI-UT-011, "IntraSpect NDE Procedure For Inspection Of Reactor Vessel Head Vent Tubes." The licensee vendor provided WDI-TJ-002-02, "Technical Justification For Eddy Current Of J-Groove Welds," as the demonstrated technical basis for this examination technique. In this document, the vendor documented the results of an internal demonstration on PWSCC cracks in VHP nozzle samples removed from the Oconee plant. In addition, the vendor demonstrated the equipment on a mockup that contained electric discharge machined notches and simulated cracks made by applying cold isostatic pressure to notches. The licensee used a X-wound ET coil at the same frequency and size to that used on the mockups, except that the onsite equipment did not include the TC 5700 Data Acquisition System. The licensee vendor documented a comparisons of the display on the mockup flaws from the TC 5700 Data Acquisition System and the IntraSpect Data Acquisition System used on site and concluded that there was no effect on the data acquired.

2.2.d Penetration Nozzle 73

Yes. For the PT examination of the outer surface of portions of nozzle 73, the licensee used a Code procedure.

In response to Order EA-03-009 and associated relaxation requests, the licensee committed to inspect the nozzles to a distance below the J-weld supported by calculations. However, the licensee could not obtain the minimum of 0.5 inch (reference CR 03143045, and EVAL-MD-02-RCS-024) below the J-weld using ET or UT techniques on nozzle 73 due to the short distance from the J-weld to the threads. To supplement the UT and ET examination of this nozzle, the licensee performed a PT examination of the outside surface of this nozzle which included the threads and ½ inch above the threads. For this examination, the licensee performed a solvent removable manual PT examination in accordance with Procedure 12-QHP-5050-NDE-001, “Liquid Penetrant Examinations For Nuclear And Non-Nuclear Welds And Components.” This procedure met the ASME Code requirements of the 1989 Edition of Section V and XI and applied the flaw acceptance criteria from the 1983 Edition, Summer 1984 Addenda of Section III.

2.2.e Penetration Nozzle 75

Yes. For the J-weld on nozzle 75, the licensee used a Code PT procedure to supplement the UT and ET examination of this nozzle. The licensee performed a PT examination of the J-weld including the outside surfaces of the nozzle. For this examination the licensee performed a solvent removable manual PT examination in accordance with Procedure 12-QHP-5050-NDE-001, “Liquid Penetrant Examinations For Nuclear And Non-Nuclear Welds And Components.” This procedure met the ASME Code requirements of the 1989 Edition of Section V and XI and applied the flaw acceptance criteria from the 1983 Edition, Summer 1984 Addenda of Section III.

2.2.f Penetration Nozzles 43 and 74

Yes. For the PT examination of the repaired areas on the inside surface of nozzles 43 and 74, the licensee used a PT tool that delivered PT chemicals remotely in accordance with MRS-SSP-1484-AMP, “Reactor Vessel Head Penetration Repair Scenarios For D.C. Cook Unit 2.” The licensee performed the actual PT examination in accordance with Procedure GQP 9.4, “Remote Flourescent Post-Emulsifiable Dye Penetrant Exam and Acceptance.” The licensee's procedure referenced applicable acceptance requirements of the ASME Code, Section III, 1989 Edition. Because the licensee was performing this PT examination using remote tooling, which was not recognized by the ASME Code, the inspectors noted deviations from Code requirements. For example, the licensee added a step to allow not performing the Code required 5 minute wait to allow the eyes of the examination personnel to adjust to lighting conditions, because the procedure was done using a remote camera system. The procedure also allowed up to 60 minutes for final interpretation of indications vice the Code required maximum of 30 minutes. The Authorized Nuclear Inservice Inspector (ANII) had observed the remote PT procedure demonstration and had approved it as a "newly developed technique" in accordance with IWA-2240 of Section XI of the ASME Code. The licensee had also performed ET of the repaired areas in accordance with Procedure WDI-ET-008, "IntraSpect Eddy Current Imaging Procedure For Inspection of Rx Vessel Head Penetrations With Gap Scanner." This was the same ET equipment and technique which the licensee vendor had used to identify the cracks in these nozzles and the licensee used this method after metal removal to confirm that the crack indications had been removed.

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 RPV head corrosion phenomena described in the bulletin?

3.1 Upper Head Bare Metal Remote Visual Examination

Unknown. At the conclusion of this inspection, the licensee was not able to identify, disposition, and resolve deficiencies and identify PWSCC at each VHP nozzle based on the visual examination. The licensee's examinations identified 17 nozzle locations (based on draft visual examination records dated May 21, 2003) which were considered indeterminate because of the presence of debris or boric acid deposits. This result precluded the licensee from confirming the absence of PWSCC based upon the visual examination. For these and other indeterminate nozzle locations, the licensee was relying on the under head ET and UT examinations to confirm the absence of PWSCC cracking induced leakage.

3.2 Under Head Volumetric and Surface Examinations

Yes. The licensee had successfully identified four VHP nozzles (43, 59, 64, and 74) with indications of shallow surface (craze) cracking at the inside nozzle surface using ET examinations. Additionally, the UT techniques used were successful at detecting simulated PWSCC in mockup tests. Therefore, the inspectors concluded that the under head UT and ET examinations were capable of detecting PWSCC.

Yes. The licensee's UT techniques were capable of detecting notches and holes in a vendor calibration standard that simulated a loss of RPV head materials. Therefore, the inspectors concluded that the licensee would have likely detected degradation induced in the RPV head in the interference zone, caused by RCS leakage through the nozzle cracks.

Yes. Other licensee have been successful at detecting PWSCC in the J-weld region using Code PT examinations. Therefore, the inspectors concluded that the Code PT examinations completed under the head were capable of identifying PWSCC cracking.

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

4.1 Top of Vessel Head Visual Examinations

The reactor head insulation consisted of reflective metal insulation panels which were 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 several penetrations contained loose debris, which generally did not hinder the licensee's evaluation of the penetration. Additionally, the licensee robotic crawler had a pressurized air source which the vendor used to blow loose debris out of the nozzle-to-head interface. Some quadrants of penetrations near insulation support structures were obstructed from the crawler mounted camera and the licensee used a fiber optic scope mounted to the crawler to view these areas. The licensee reported that a 100 percent visual examination of the VHP nozzle-to-head interface was achieved for all 78 head penetrations and the head vent location. However, the licensee identified several nozzle locations which were considered indeterminate based on the presence of debris or boric acid deposits at the interface. The licensee also removed a brick of asbestos insulation material wrapped in fiberglass cloth from the top of the vessel head under the insulation support structure.

The licensee performed a systematic inspection and documented the visual examination results of each of four quadrants on each VHP nozzle-to-vessel interface. No indications of head leakage were recorded. The licensee's remote examination noted several penetrations with white stains running down the penetration nozzle into the interface area. The licensee's remote visual examination also identified a rust contrail which appeared to originate at nozzle 17 (CR 03137028). The inspectors performed a direct visual examination of penetration nozzle 17 and noted that the rust contrail originated from the VHP nozzle- to-head interface. The inspectors did not observe any white deposits (boric acid) which have been the typical indicator of coolant leakage. The inspectors also reviewed the UT examination results for VHP nozzle 17 and noted that no leakage path or cracking was identified.

4.2 Under Vessel Head Ultrasonic and Eddy Current Examinations

The surface of the inner bore of the CRDM penetrations was sufficiently smooth, such that the quality of the UT and ET examinations was not affected. An exception to this, was the surface condition of the weld repair area for nozzle 75. The licensee had identified PWSCC and performed an embedded flaw repair at the inside surface of VHP nozzle 75 during a prior Unit 2 outage in 1994. The surface condition of the nozzle at this location precluded a meaningful UT examination of the embedded flaw below the repair weld. The licensee vendor compared ET results from the previous ET examination and concluded that the repair area had not changed in size.

4.3 Under Vessel PT Examinations

The licensee did not identify any surface conditions which precluded obtaining acceptable PT examinations for the nozzle and weld surfaces examined except at the nozzle 75 J-weld. On May 23, 2003, during this PT examination, the licensee identified a "broad area of pigmentation" on the J-weld of nozzle 75 that could have masked relevant indications and was caused by incomplete cleaning of the penetrant material prior to application of the developer. The licensee re-performed this examination on May 31, 2003, and achieved a successful Code PT examination.

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

Unknown. At the conclusion of the inspection, the licensee was not able to resolve small boron deposits at each head penetration based on the remote visual examination. Licensee personnel had access to each of the head penetrations (78 total) and head vent nozzle to perform the remote visual examination. However, based on draft visual examination records as of May 21, 2003, the licensee's examinations noted 17 nozzle locations which were considered indeterminate based on the identification of debris or boric acid deposits. For example, at the head vent nozzle penetration, the licensee identified an aspirin size deposit of boric acid which appeared to be wedged at the interface. This deposit did not appear to be consistent with the leaks from plants with confirmed nozzle cracking documented in EPRI Report TR 1006296, "Visual Examination For Leakage Of PWR Reactor Head Penetrations." However, the licensee could not attribute this deposit of boric acid to rundown from a leakage source above the head, so the licensee inspector considered the nozzle examination as indeterminate. At VHP nozzle 47, the licensee identified a boric acid deposit that filled in the interface area. Although this type of boric acid deposit was not characteristic of plants that have confirmed nozzle leakage, the licensee's examiner considered the nozzle indeterminate due to the potential masking effects of this deposit. For these and other indeterminate nozzle locations, the licensee was relying on the under head ET and UT examinations to confirm the absence of coolant leakage caused by PWSCC. At the conclusion of this inspection, the licensee had performed vacuum cleaning of the debris at the interface regions and was re-inspecting the indeterminate nozzle locations.

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

On May 15, 2003, the licensee vendor identified axial crack indications on the inside diameter surface of VHP nozzle 74 during the Unit 2 reactor head inspection. The licensee determined that the VHP nozzle 74 cracks were a maximum of 0.117 inches deep based on UT results and had a maximum length of 2.6 inches based on ET data. This area of surface cracks had been identified during the previous Unit 2 head examination and found to be acceptable for service. Further, the licensee concluded that the crack indications had not changed appreciably in size based upon comparison with previous inspection results.

The licensee stated that a vendor evaluated the crack indications in penetration No. 74 using a flaw growth formula derived from EPRI MRP-55, "Materials Reliability Program Crack Growth Rates For Evaluating Primary Water Stress Corrosion Cracking (PWSCC) Of Thick-Wall Alloy 600 Materials," Revision 1. The inspectors confirmed that the flaw growth rate specified in MRP-55 was consistent with that accepted by the NRC in the April 11, 2003, letter from R. Barrett (NRC) to A. Marion (Nuclear Energy Institute). Based upon this evaluation, the licensee determined that penetration 74 would not to be serviceable for a full cycle of plant operation. Specifically, the licensee determined that this cluster of cracks could grow to 75 percent through wall (the maximum allowable) in 1.05 effective full power years (EFPY). Because Cycle 14 was 1.33 EFPY, the licensee could not return the reactor head to service for a full cycle of operation with these cracks in place and initiated repairs to penetration 74.

The licensee also identified shallow crack indications in VHP nozzles 43, 59, and 64, which did not require repair based upon calculations of maximum expected flaw growth. For these nozzles, the ET indications identified were typically axial and located at or below the J-weld at the inside diameter surface except for penetration 64 cracking which was slightly above the J-weld.

The licensee recorded the following dimensions for these indications:

Penetration No.	ET Indication No.	L1 & L2	Angle 1 & Angle2	Disposition
43	1	5.06 & 5.62	156 & NA	Group of Multiple Axial Indications.
	2	4.98 & 5.74	165 & NA	
	3	5.180 & 5.9	174 & NA	
	4	4.98 & 5.66	180 & NA	
59	1	6.44 & 6.64	176.5 & 176.5	Single Axial Indication (SAI)
	2	4.52 & 4.88	155.5 & 155.5	SAI

Penetration No.	ET Indication No.	L1 & L2	Angle 1 & Angle2	Disposition
	3	4.32 & 4.88	166 & 166	SAI
	4	4.44 & 4.84	178 & 178	SAI
	5	4.52 & 4.96	2.5 & 2.5	SAI
64	1	6.32 & 6.6	162 & 162	SAI
	2	6.36 & 6.52	179 & 179	SAI
	3	5.72 & 5.88	171 & 171	SAI
	4	5.56 & 5.64	182 & 182	SAI
	5	4.56 & 4.72	160 & 160	SAI
	6	4.44 & 4.88	181 & 181	SAI
	7	4.48 & 4.92	346 & 346	SAI
	8	4.8 & 5	350 & 350	SAI
74	1	5.8 & 8.7	167 & 203	Cluster of Multiple Axial Indications

Note. The axial length (in inches) of the indications is L1-L2, and the circumferential extent is Angle 1-Angle 2 (in degrees).

The licensee implemented repairs to VHP nozzle 74 by excavating the cracks and associated base metal (nominal 0.625 inch wall thickness) using an electric discharge machining tool. The licensee also elected to perform the same repair to VHP nozzle 43 which had a larger cluster of flaws, even though the licensee vendor had indicated that this flaw would remain within an acceptable size for a full cycle of operation. The licensee performed metal removal on VHP nozzles 43 and 74 in accordance with Procedure MRS-SSP-1484-AMP, "Reactor Vessel Head Penetration Repair Scenarios For D.C. Cook Unit 2." The licensee removed 0.127 inches and 0.129 inches of metal from the inside surface of nozzles 43 and 74, respectively.

The licensee provided WCAP-14563, "Determination Of Maximum Excavation Depth On Reactor Head Penetrations For D.C. Cook Units 1 & 2," as the basis for the maximum allowable amount of metal removed for the nozzle repairs. In this document, the licensee vendor performed stress and fatigue analysis at the vessel head penetration for inside surface excavations up to 0.315 inch depth. The inspectors identified that the licensee had not subtracted appropriate measurement uncertainties (0.015 inches) and metal removed during honing (0.012 inches) from the maximum allowable amount of metal (0.315 inches) which could have been removed under Procedure MRS-SSP-1484-AMP. Because the actual amount of metal removed including measurement uncertainty and honing was within the bounds of the stress analysis, there was no impact on the integrity of the repaired VHP nozzles. The inspectors also confirmed that the licensee had applied acceptance criteria consistent with the installation Code identified in the licensee’s repair plan, Section III of the 1989 Edition of the ASME Code, for the PT examination of the repaired areas of VHP nozzles 43 and 74.

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)?

For examinations of penetration nozzles which were observed by the inspectors, the licensee was able to obtain coverage consistent with licensee commitments to NRC Order EA-03-009, except for a small area at the bottom end of each nozzle. The licensee could not examine a short segment at the bottom of the CRDM nozzles due to a threaded configuration on the outside of the penetration nozzles which served to connect to guide funnels at some locations. This area of limited NDE coverage was approximately 0.75 inches in length at the end of the penetration nozzle. The licensee had submitted by letter dated March 26, 2003, a request for relaxation to Order EA-03-009 requirements, to address this limitation in the extent of NDE. This licensee relaxation request was under review at the conclusion of this inspection. The inspectors noted that each of the 78 head penetration nozzles contained this threaded region at the end of the nozzle. For penetrations 1-9, the licensee could only perform the ET scan on the outside surface of the penetration nozzle to within an estimated 3-4 millimeters above the threaded area. Additionally, a chamfer edge of 0.23 inch vertical height on the inside surface at the bottom of each of the nozzles precluded UT or ET examination coverage below this point.

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 licensee’s to calculate the susceptibility category of each reactor head to PWSCC-related degradation. The susceptibility category in total effective degradation years (EDY) establishes the basis for the licensee to perform appropriate head inspections during each refueling outage. The licensee documented calculation of the Unit 2 RPV head EDY in DIT B-02726-00 using a formula consistent with Order EA-03-009 and determined that as of April 25, 2003, the Unit 2 RPV head had 14.56 EDY. This value placed the Unit 2 RPV head in the high susceptibility category. NRC Order EA-03-009 also required the licensee use best estimate values in determining the susceptibility category for the vessel head. The inspectors were able to confirm, based on verbal discussions with cognizant licensee and vendor personnel, that plant specific information had been used in the determination of vessel head temperatures in the susceptibility ranking calculation for the Unit 2 RPV head.

In DIT B-02726-00, the licensee referenced the source document for the Unit 2 vessel head operating temperature as MRP-48, “PWR Materials Reliability Program Response to NRC Bulletin 2001-01,” dated August 2001. However, MRP-48 did not contain any reference to confirm the source of the head temperatures identified for Unit 2. The licensee staff stated that they believed that the head temperatures were derived by a vendor using plant specific information and a vendor proprietary THRIVE computer program. The licensee provided vendor document WIN 284-6397, “Upper Head Temperatures for Westinghouse Plants Based on Plant Operating Data Survey,” dated November 4, 1992. This document was consistent with the MRP-48 values used for Unit 2 head temperatures; 595.5 degrees Fahrenheit for the first 3 operating cycles and 600.7 degrees Fahrenheit for the next five operating cycles. However, this vendor document did not identify if plant specific information was used to determine the vessel head temperature for each cycle. Based on verbal confirmation from the licensee vendor, the inspectors concluded that applicable plant specific information had been used in determination of the vessel head temperatures. Specifically, the vendor had used values of RCS cold leg temperature and thermal power level documented in the 1992 vendor internal memorandum, to derive a representative bulk fluid head temperature.

In review of the EDY calculation, the inspectors identified a minor error in the EFPY value used in this calculation. The inspectors determined that the EFPY value should have been 11.50 years instead of 11.52 years for cycles 4 through 13 based on the input values documented in DIT S-00705-03. This minor calculation error was in the conservative direction and did not affect the EDY output or classification of the Unit 2 head in the high susceptibility category. In addition to the EDY, an acceptable vessel susceptibility evaluation must consider past experience with nozzle cracking. The inspectors identified that the calculation did not contain or reference the fact that Unit 2 had known penetration cracking which would place it in the high susceptibility category irrespective of the calculated EDY results.

10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires in part, that activities affecting quality shall be prescribed by documented instructions appropriate to the circumstances. Contrary to this requirement, the licensee failed to have instructions in DIT B-02726-00 regarding the source of the vessel head temperature (or the plant specific input values used to derive the parameter) as input to the EDY calculation, had a minor math error, and had not referenced or documented PWSCC cracking which had been previously identified in Unit 2 nozzles 74 and 75, which was a violation of 10 CFR 50, Appendix B, Criterion V. However, because the calculated value resulted in the high susceptibility category and the licensee had implemented inspections consistent with NRC Order EA-03-009 for this category, the inspectors considered this violation to be of only minor significance. The licensee documented this minor violation in their corrective action program as CR 03148059.

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?.

Yes. The licensee's vendor performed a flaw growth evaluation for flaws in nozzles 59 and 64 as documented in letter AEP-03-48, "Sensitivity Study Information For Unit 2 Relaxation Request," from R. Rice (Westinghouse) to C. Bakken (licensee) dated June 2, 2003. The licensee performed an owners acceptance review of this letter and determined that the flaws in these VHP nozzles would remain within service limits acceptable to the NRC for a minimum of 1.79 years. The inspectors reviewed this evaluation and portions of vendor source calculation LTR-PAFM-03, "Supporting Calculation Information For D. C. Cook Unit 2 Flaw Growth Sensitivity Study," and confirmed that the licensee applied a flaw growth rate and calculation methodology consistent with that accepted by the NRC in a letter dated April 11, 2003, from R. Barret (NRC) to A. Marion (Nuclear Energy Institute). However, the inspectors identified that the licensee had used flaw dimensions (without allowance for NDE sizing errors) that were not consistent with that measured by ET and documented in the examination reports for these nozzles. The licensee flaw evaluation had used flaw depths of 0.05 inches and 0.1 inches and a bounding flaw length of 0.6 inches. However, the inspectors identified that existing ET examination reports for penetration 59 had recorded flaws up to 1.2 inches in length. The licensee re-analyzed the recorded ET data for penetrations 59 and 64 and confirmed that the crack indiction sizes used in the flaw evaluation bounded the actual crack sizes in nozzles 59 and 64.

10 CFR 50, Appendix B, Criterion III, "Design Control," requires in part, that measures shall be provided for verifying or checking the adequacy of the design. Contrary to this requirement, the licensee failed to conduct adequate checking of design inputs (flaw sizes) used in the "Sensitivity Study Information For Unit 2 Relaxation Request," from R. Rice (Westinghouse) to C. Bakken (licensee) dated June 2, 2003, since the flaw sizes used were not consistent and confirmed by documented ET examination records. The failure to conduct adequate reviews in the owner review and acceptance of "Sensitivity Study Information For Unit 2 Relaxation Request," was an example of a violation of 10 CFR 50, Appendix B, Criterion III. However, because the licensee's re-evaluation of ET data confirmed that bounding flaw sizes had been used in this flaw evaluation, there was no impact on component operability. Therefore, the inspectors considered this violation to be of only minor significance. The licensee documented this issue in their corrective action system as CR 03155017.

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 including 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 Procedure 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-001, "Visual VT-2 Examination: RCS System Leakage Test." These procedures provided for detection and disposition of boric acid on components. In general, boric acid deposits were divided 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-001 provided further guidance for boric acid deposits on insulation. This procedure stated, "IF, evidence of leakage is observed, THEN remove the insulation to determine the source of leakage."

The inspectors interviewed licensee staff who were involved in the most recent containment area inspections to detect leakage including the area above the Unit 2 vessel head. The inspectors noted that licensee staff understood the procedure requirements and appeared to be adequately trained to identify boric acid leakage.

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

    Yes. The inspectors reviewed licensee corrective actions for dry boric acid deposits which were identified during system leakage tests and documented in their corrective action system. In January 26, 2003, at the packing area of valve 2-RC-121 (CR 03026011) and on May 9, 2000, for the number 4 CETNA seal leak (CR P-00-06663), the licensee identified boric acid deposits. The leakage at these components was limited and the licensee did not identify any boric acid deposits which contacted the vessel head or insulation. For these indications of leakage, the licensee cleaned up the boric acid deposits and corrected the source of the leakage. In CR 03026011, the licensee incorrectly stated that valve 2-RC-121 did not have a history of packing leakage. The inspectors identified that on February 24, 2002, during 12-QHP-5070.NDE.001, "Visual VT-2 Examination: RCS System Leakage Test," the licensee had documented a leak at the No. 4 CETNA seal (with dry boric acid residue) and on 2-RC-121 packing (active wet leak). For each of these areas the licensee had documented the leakage as being corrected. However, for the number 4 CETNA seal, the licensee had referenced ESAT 02055022, which did not identify this seal area as leaking. To confirm that the licensee had taken appropriate actions, the inspectors performed a walkdown of the 2-RC-121 and number 4 CETNA seal area and confirmed the absence of boric acid deposits in these areas.

c. <u>Findings</u>

No findings of significance were identified.

.2 <u>(Closed) URI 50-316/02-09-07</u>: "Review of NOED-02-3-058 Regarding D. C. Cook, Unit 2, Compliance With TS 3.8.1.1." By letter dated November 6, 2002, the licensee requested that the NRC exercise enforcement discretion regarding compliance with the actions of TS 3.8.1.1.b for operability of the Unit 2 CD EDG. The inspectors opened URI

50-316/02-09-07 to track documentation of the root cause for the Notice of Enforcement Discretion (NOED) request, review the NOED approval basis, and verify licensee activities associated with NOED implementation. As discussed in Sections 1R12 and 4OA3.2 of this report, the inspectors reviewed the performance history of the Unit 2 CD EDG governor to determine if the licensee had prior opportunities to identify and correct the load swings prior to requesting an NOED. The inspectors concluded that the licensee's actions to address the condition prior to November 6, 2002, were inadequate and constituted a violation of NRC requirements. The inspectors concluded that the licensee provided a reasonable basis for the NOED and appropriately implemented compensatory measures. This URI is closed.

.3 (Closed) URI 50-316/02-02-03: "Failure to Follow Radiation Protection Requirements."

On January 28, 2002, a contractor failed to follow the instructions of an RP technician and failed to immediately exit the work area in the Unit 2 Containment Building when the employee's electronic dosimetry alarmed. The NRC Office of Investigations reviewed the matter and concluded that the individual deliberately failed to obey the instructions of an RP technician to stop work and evacuate the work area and subsequently failed to immediately leave the work area after the employee's electronic dosimetry alarmed, contrary to RP procedures.

Since the incident was determined to be a deliberate violation of NRC requirements, the violation was not subject to the NRC's significance determination process, as described in NRC IMC 0609, "Significance Determination Process." The violation was categorized in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, at Severity Level IV. On May 16, 2003, a Notice of Violation was issued to the licensee (Accession Number ML031400885). The involved individual was determined to be in violation of the regulations in 10 CFR 50.5 that prohibit deliberate misconduct; however, no enforcement action was taken against the individual. A closure letter was issued to the individual on May 17, 2003.

4OA6 Meetings

.1 Interim Exit Meetings

The results of an Annual Licensed Operator Requalification Testing inspector review were presented to Mr. W. Davidson by telephone on May 9, 2003. The licensee acknowledged the findings presented.

The results of the Occupational Radiation Safety - Access Controls for Radiologically Significant Areas and ALARA Planning/Controls Inspection were presented to Mr. A. C. Bakken and other members of licensee management at the conclusion of the inspection on April 25, 2003. The licensee acknowledged the findings presented.

The results of Temporary Instruction 2515/150 and inservice inspection (IP 7111108) were presented to Mr. C. Bakken on May 23, 2003 and June 4, 2003, respectively.

.2 Resident Inspector Exit Meeting

The inspectors presented the inspection results to Mr. J. Pollock and other members of licensee management at the conclusion of the inspection on June 25, 2003. 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 discussed in this report.

.3 Annual Assessment Meeting

On April 10, 2003, the NRC presented the results of its annual assessment of D. C. Cook Plant performance to Mr. A. C. Bakken and other members of licensee management during a public meeting held at the Park Inn in Stevensville, Michigan. The results of the annual assessment were previously documented in a letter to the licensee dated March 4, 2003. The slides presented by the NRC are available in ADAMS (accession number ML030920499).

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

A.. Bakken, Senior Vice President
P. Cowan, System Engineering Manager
W. Davidson, Operations Requalification Training Supervisor
M. Finissi, Plant Manager
J. Gebbie, Assistant Director Plant Engineering
J. Giessner, Director, Design Engineering and Regulatory Affairs
T. Noonan, Performance Assurance Director
J. Pollock, Site Vice President
S. Simpson, Assistant Operations Director
D. Wood, Radiation Protection/Environmental Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-316/03-06-01	NCV	Failure to Correct 2CD EDG Load Oscillations (Section 1R12)
50-316/03-06-02	URI	Unplanned Scrams with Loss of Normal Heat Removal Performance Indicator Questions (Section 4OA1.1)
50-316/03-06-03	NCV	Failure to Correct Reactor Control Instrumentation Power Supply Failures (Section 4OA3.1)
50-316/03-06-04	VIO	Failure to Follow Radiation Protection Requirements (Section 4OA5.3)

Closed

50-316/03-06-01	NCV	Failure to Correct 2CD EDG Load Oscillations (Section 1R12)
50-316/03-06-03	NCV	Failure to Correct Reactor Control Instrumentation Power Supply Failures (Section 4OA3.1)
50-316/2003-002-00	LER	Unit 2 Trip Due to Power Supply Failure (Section 4OA3.1)
50-316/2002-007-00	LER	TS 3.8.1.1 Allowed Outage Time Exceeded (Section 4OA3.2)
50-316/2003-001-00	LER	Unit 2 TS 3.8.1.1 Required Shutdown (Section 4OA3.3)
50-315/1999-023-01	LER	Retraction of LER 50-315/1999-023-00 (Section 4OA3.5)
50-316/02-09-07	URI	Review of NOED 02-3-058 (Section 4OA5.2)
50-316/02-02-03	URI	Failure to Follow Radiation Protection Requirements (Section 4OA5.3)

Discussed

50-316/02-09-02	NCV	Failure to Take Corrective Actions to Address Reactor Control Instrumentation Power Supply Failures (Section 4OA3.1)
50-316/2002-005-00	LER	Unit 2 Trip Due to 24-Volt DC Power Supply Failure (Section 4OA3.1)
50-316/02-09-01	NCV	Failure to Take Corrective Actions to Address Reactor Control Instrumentation Power Supply Failures (Section 4OA3.1)

LIST OF ACRONYMS USED

ADAMS	Agency-wide Documents and Management System
ALARA	As-Low-As-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
B	Barrier Integrity
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CVCS	Chemical Volume Control System
CY	Calender Year
DC	Direct Current
DIT	Design Information Transmittal
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
EFPY	Effective Full Power Years
EGB	Governor Hydraulic Actuator
EGM	Electronic Governing Module
EHP	Electrical Maintenance Head Procedure
EP	Emergency Preparedness
EPRI	Electrical Power Research Institute
eSAT	Electronic Single Action Tracking
ESF	Engineered Safety Feature
ESW	Essential Service Water
ET	Eddy Current
FAQ	Frequently Asked Question
ICM	Interim Compensatory Measures
IE	Initiating Events
IHP	Instrument Maintenance Head Procedure
IMC	Inspection Manual Chapter
IST	Inservice Testing
KW	Kilowatts
LER	Licensee Event Report
LERF	Large Early Release Frequency
LCO	Limiting Condition For Operation
MHP	Maintenance Head Procedure
MS	Mitigating System
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NOED	Notice of Enforcement Discretion
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OA	Other Activities

OHP	Operations Head Procedure
OPR	Operability Recommendation
OWA	Operator Work-Arounds
PARS	Publically Available Records
PI	Performance Indicator
PMI	Plant Manager's Instruction
PMP	Plant Manager's Procedure
PORV	Power Operated Relief Valve
PT	Dye Penetrant
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RP	Radiation Protection
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SAI	Single Axial Indication
SDP	Significance Determination Process
SG	Steam Generator
SSC	Structures, Systems, and Components
STP	Surveillance Test Procedure
TEDE	Total Effective Dose Equivalent
TI	Temporary Instruction
TOFT	Time-Of-Flight-Tip-Diffraction
TRU	Transuranic Nuclide
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic
U2C14	14^{th} Unit 2 Refueling Outage
VHP	Vessel Head Penetration
WSI	Water System Indication

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. 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, unless specifically stated in the inspection report.

1R01 Adverse Weather Protection

PMI 5055	Winterization/Summerization	Revision 1
PMP 5055-001-001	Winterization/Summerization	Revision 0
PMP 2080-SWM-001	Severe Weather Guidelines	Revision 0
12-OHP 4022.001.010	Severe Weather	Revision 1
12-IHP-5040-EMP-004	Plant Winterization and De-Winterization	Revision 3
Significant Operating Experience Report 02-1	Severe Weather	December 3, 2002
Job Order R0230414	Perform Plant De-Winterization	May 1, 2003
CR 02170009	Housekeeping in Switchyard	June 19, 2002
CR 03133041	Materials Staged Directly Adjacent to the Unit 1 Normal and Reserve Feed Transformers.	May 13, 2003
CR 03133054	Issues Identified During Resident Tour of 765 kV and 345 kV Switchyards.	May 13, 2003

1R04 Equipment Alignment

01-OHP-4021-017-002	Placing in Service the Residual Heat Removal System	Revision 16
02-OHP-4030-205-002V	Lineup Sheet 2: Boration System Valve Position Verification and Testing	Revision 0b
12-OHP-4021-018-002	Placing in Service and Operating the Spent Fuel Pit Cooling and Cleanup System	Revision 11a
OP-1-5143-59	Flow Diagram: Emergency Core Cooling RHR Unit 1	Revision 59
OP-2-5129-39	Flow Diagram: CVCS - Reactor Letdown and Charging Unit 2	Revision 39

OP-2-5129A-32	Flow Diagram: CVCS - Reactor Letdown and Charging Unit 2 Sheet 1	Revision 32
OP-2-5128-22	Flow Diagram: Reactor Coolant Unit 2 Sheet 1 of 2	Revision 22
OP-12-5131-42	Flow Diagram: CVCS - Boron Make-Up Unit 1 and Unit 2	Revision 42
OP-12-5136-21	Flow Diagram: Spent Fuel Pit Cooling & Clean-Up Unit 1 and Unit 2	Revision 21

1R05 Fire Protection

	D. C. Cook Nuclear Plant Updated Final Safety Analysis Report, Section 9.8.1, "Fire Protection System"	Revision 18
	D. C. Cook Nuclear Plant Fire Hazards Analysis, Units 1 and 2	Revision 10
	D. C. Cook Nuclear Plant Units 1 and 2 Probabilistic Risk Assessment, Fire Analysis Notebook	February 1995
	D. C. Cook Nuclear Plant Administrative Technical Requirements Manual, Sections 1-FP-7 and 2-FP-7, "Fire Rated Assemblies"	Revision 31
PMP-2270-CCM-001	Control of Combustible Materials	Revision 1
PMP-2270-WBG-001	Welding, Burning and Grinding Activities	Revision 0b
PMP-5020-RTM-001	Restraint of Transient Material	Revision 1
PMI-2270	Fire Protection	Revision 26a
12-PPP-2270-066-001	Portable Fire Extinguisher Inspections	Revision 0b
12-PPP-4030-066-021	Inspection of Fire Dampers Protecting Safety-Related Areas	Revision 1c
CR 03153003	NRC Identified that Emergency Lighting Battery Pack 1-BATLIT-448 for Unit 1 South SI Pump Room Has a Failed Battery Charge Meter.	June 2, 2003
CR 03153008	NRC Identified Rag Stuffed Into the Grating of the Unit 1 North Safety Injection Pump Room Block Wall.	June 2, 2003

1R07 Heat Sink Performance

12-MHP-5030-016-001	Component Cooling Water Heat Exchanger Inspection, Cleaning and Tube Plugging	Revision 5
Generic Letter 89-13	Service Water System Problems Affecting Safety-Related Equipment	July 18, 1989
Generic Letter 89-13, Supplement 1	Service Water System Problems Affecting Safety-Related Equipment	April 4, 1990
Letter from Indiana Michigan Power to NRC AEP:NRC:1104	Generic Letter 89-13 Service Water System Problems Response	January 25, 1990
Letter from Indiana Michigan Power to NRC AEP:NRC:1104A	Generic Letter 89-13; Service Water System Problem Response	January 30, 1991
Job Order R0227595-03	2-HE-15E Perform Heat Exchanger Cleaning/Inspection	May 30, 2003
Job Order R0230207-02	1-HE-15W Open, Inspect, Clean, Close Heat Exchanger	May 4, 2003
Job Order R0230606-03	1-HE-15E Open, Inspect, Clean, Close Heat Exchanger	May 16, 2003
Job Order R0227597-04	2-HE-15W Perform Heat Exchanger Cleaning/Inspection	May 21, 2003
CR 03130001	Calculation MD-12-ESW-102-N, Revision 0, CCW Heat Exchanger Channel Flange Evaluation Assumed a Smaller Corrosion Allowance for the Unit 1/2 Heat Exchangers.	May 10, 2003
CR 03130009	Generic Letter 89-13 Inspection Found More Tubes Plugged in Heat Exchanger 1-HE-15W Than Allowed.	May 10, 2003
CR 03138019	Results of Eddy Current Testing on the Unit 1 East CCW Heat Exchanger.	May 18, 2003
CR 03139096	Pipe Between 2-WMO-724 and 2-ESW-144 Is Approximately 1/3 Full of Fine Sand Grit.	May 19, 2003
CR 03140074	Generic Letter 89-13 Inspections Determined that 32 Tubes Were Obstructed in the 2-QT-131-AB Cooler.	May 20, 2003

1R11 Licensed Operator Requalification

	Licensed Operator Requalification Training Annual Simulator Evaluation Scenarios for June 24, 2003	

1R12 Maintenance Effectiveness

PMP-5035-MRP-001	Maintenance Rule Program Administration	Revision 4
12-MHP-5021-056-007	Turbine Driven Auxiliary Feed Pump Trip and Throttle Valve Linkage Adjustment	Revision 4
PMI-5035	Maintenance Rule Program	Revision 10
Part 21 Report 10 CFR 21-0086	10 CFR 21 Reporting of Defects and Non-Compliance - Engine Systems, Inc.	Revision 0
LER 316-2002-007-00	Technical Specification 3.8.1.1 Allowed Outage Time Exceeded	December 13, 2002
LER 316-2003-001-00	Unit 2 Shutdown in Accordance with Technical Specification 3.8.1.1, A.C. Sources, Action b	March 20, 2003
NTS-2003-003-REP	Unit 2 CD EDG Load Oscillation Technical Evaluation MPR-2506, Revision 1	April 10, 2003
Vendor Drawing X-590900AZ	Arrangement of Fuel Pump Control Shaft 14 x 18 SW-14-12 (Front Bank) Supercharged Diesel Engine	November 8, 1966
VTD-WORT-0014 DWG NO X-590900AZ	Arrangement of Governor Control Linkage	January 13, 1970
	Daily Shift Manager's Logs	January 24, 2003 through January 27, 2003
CR P-99-20129	Tripped Unit 2CD EDG Due to Load Swings from 3200 kW to 1000 kW.	August 2, 1999
CR 02039004	During the Post Maintenance Test Run of the CD EDG, It Had to Be Stopped After 1 Minute Due to Speed Cycling.	February 8, 2002
CR 02306005	CD EDG Exhibited 150 kW Oscillations at Full Load During Surveillance Testing.	November 2, 2002

CR 02307003	1-PP-26N Oil Reservoir Sight Glass Found to Have Wrong and Missing Parts.	November 11, 2002
CR 03025002	At Full Load (3500 kW), DG2CD Experienced 150 kW Load Swings.	January 25, 2003
CR 03026001	Unit 2 Required Plant Shutdown Due to Unit 2 CD EDG Inoperability About to Exceed 72 Hours.	January 26, 2003
CR 03026022	The Configuration of the EDG Output Linkages are Not in Accordance with Worthington Drawing 590930CE.	January 26, 2003
CR 03026041	PMT Torque Testing for EDG Fuel Rack Does Not Test As Left Condition for Linkage that Connects to the Governor.	January 26, 2003
CR 03026044	There Appears to Be a Washer at the 2CD Diesel Fuel Rack Lever Which Is Not in Compliance with Worthington Corporation Drawing 590930CE.	January 26, 2003
CR 03027059	During Investigation of the EGM Control Module Found that on Some EGM Modules the Potentiometers R1 and R4 Have Been Reversed.	January 27, 2003
CR 03028028	The 2CD EDG Experienced a Surge in Load During Post Maintenance Testing.	January 28, 2003
CR 03041036	Governor Sight Glass Provides Erroneous Indication While Operating.	February 10, 2003
CR 03154060	While Performing Procedure 12-MHP-5021-056-007, Steps Not Acceptable.	June 3, 2003

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

PMP-2291-OLR-001	On-Line Risk Management	Revision 3
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
	Shift Manager’s Logs	April 1, 2003 through June 30, 2003

PMP-2291-OLR-001 Data Sheet 1	On-Line Risk Management Work Schedule Review and Approval Form Cycle 45, Week 4	March 30, 2003 through April 5, 2003
PMP-2291-OLR-001 Data Sheet 1	On-Line Risk Management Work Schedule Review and Approval Form Cycle 45, Week 5	April 6, 2003 through April 12, 2003
PMP-2291-OLR-001 Data Sheet 1	On-Line Risk Management Work Schedule Review and Approval Form Cycle 45, Week 8	April 27, 2003 through May 3, 2003
12-OHP-5030-057-001	Screen House Vulnerability Determination	Revision 0
02-OHP-4022-001-006	Rapid Power Reduction Response	Revision 3 Draft
12-OHP-4022-057-001	Screen House Forebay Degraded Condition	Revision 1
02-OHP-4030-208-053A	ECCS Valve Operability Test - Train A	Revision 0a
02-OHP-4030-214-034	Local Valve Position Verification Test	Revision 1a

1R15 Operability Evaluations

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 4
PMP-7030-ORP-001	Operability Determinations	Revision 9
CR 02346017	There Have Been Repeat Instances of Inconsistencies in Regards to Application of Cascading Technical Specifications.	December 11, 2002
CR 02350015	Unit 2 Hydrogen Recombiner Maintenance Was Scheduled During the 1E ESW Pump Replacement.	December 16, 2002
CR 03041019	Emergency Response Procedures States that the Flow for the Turbine Drive Auxiliary Feedwater Pump Must Be Kept Below 470,000 lbm/hr to Prevent Pump Runout. Simulator Operations During Pump Runout at Indicated Flow of Approximately 410,000 lbm/hr.	January 14, 2003

CR 03022022	Auxiliary Feedwater Flow Retention Setpoints May Not Appropriately Account for the Emergency Leak-off Flow.	January 22, 2003
CR 03039011	The Closure Time for Unit 2 Main Turbine Stop Valve Number 3 Was Abnormally Slow After the February 5 Turbine Trip.	February 8, 2003
CR 03056011	Evaluate Vendor Notification 39512 for Applicability to Cook Nuclear Plant.	February 25, 2003
CR 03080043	Unit 1 Automatic Makeup to the Stator Water System Doesn't Work.	March 21, 2003
CR 03114044	Unit 1 and 2 AB and CD EDGs Operable but Degraded Due to Degraded ESW.	April 24, 2003
CR 03115014	Unit 2 AB EDG Air Aftercooler Temperature Control Air Operated Valves 2-WRV-726 and 2-WRV-728.	April 25, 2003

<u>1R16</u> <u>Operator Workarounds</u>

02-OHP-4023-E-0	Reactor Trip or Safety Injection, Steps 1-4	Revision 19
02-OHP-4023-E.0	Reactor Trip or Safety Injection, Steps 1-5	Revision 12
02-OHP-4023-E.0	Reactor Trip or Safety Injection, Steps 1-5	Revision 7
02-OHP-4023-E.0	Reactor Trip or Safety Injection, Steps 1-5	Revision 6
02-OHP-4023-ES-0.1	Reactor Trip Response, Step 1	Revision 16
02-OHP-4023-ES-0.1	Reactor Trip Response, Steps 1-3	Revision 16
02-OHP-4023-ES-0.1	Reactor Trip Response, Steps 1-3	Revision 7
02-OHP-4023-ES-0.1	Reactor Trip Response, Steps 1-3	Revision 6
	Internal Memo from W. G. Smith, Jr. to M. P. Alexich Regarding Unit 2 Control Rod H-8 Problem	March 17, 1983
Westinghouse AEP-79-634	Letter from F. Noon, Westinghouse to D. V. Shaller, Plant Manager, D. C. Cook Nuclear Plant Regarding D. C. Cook 2 Driveline Qualification	November 26, 1979

Westinghouse Report PE-RVP-2884	Video Inspection of the H-8 Drive Line Components, Review 7 Sets of AMP and AEP Rod Drop Testing Traces, and the AMP Start-up CRDM [Control Rod Dive Mechanism] Stepping Test Traces	November 20 through November 23, 1979
	Internal Memo From R. W. Hennen to R. S. Keith Regarding Location of RCCA 113 in Unit 2 Cycle 3 Core	April 28, 1981
	Internal Memo From V. VanderBurg Regarding Unit 2, H-8 RPI Performance	January 29, 1980
	Internal Memo From W. G. Smith, Jr. to B. H. Bennett Regarding CR 02-01-83-132	July 6, 1984
	Internal Memo From W. L. Zimmermann to J. M. Cleveland Regarding CR 02-01-83-132	May 29, 1984
EVAL-MD-02-RCS-019-S	Evaluation of Reactor Coolant System Cooldown Following Reactor Trip	Revision 0
Operator Workaround 01-02	Feedwater Preheat Valves Cause Cooldown During a Reactor Trip	October 24, 2001
PMP-4010-TRP-001	Unit 2 Reactor Trip Review Report, Data Sheet 9	May 12, 2002
PMP-4010-TRP-001	Unit 2 Reactor Trip Review Report, Data Sheet 9	July 22, 2002
PMP-4010-TRP-001	Unit 2 Reactor Trip Review Report, Data Sheet 9	February 5, 2003
	Shift Manager’s Logs	October 7, 2001
	Shift Manager’s Logs	May 12, 2002
	Shift Manager’s Logs	July 22, 2002
	Shift Manager’s Logs	February 5, 2003
CR P-99-03766	Unit 2 Control Rod H-8 Doesn’t Indicate Full Insertion After Reactor Trip	February 26, 1999
CR 02-01-83-132	Following Reactor Trip, Rod H-8 CB "D" Failed to Indicate Rod Bottom Light or Indication That Rod Was Tripped.	January 27, 1983
CR 02203007	Excessive RCS Cooldown After Automatic Unit 2 Reactor Trip.	July 22, 2002

CR 02305075	The NRC Senior Resident Inspector Questioned the D. C. Cook Plant Design Which Has Frequently Required Closure of the Main Steam Isolation Valves to Terminate an Excessive RCS Cooldown.	November 1, 2002
CR 03037028	Excessive Unit 2 RCS Cooldown After Trip from 100 Percent Power.	February 5, 2003
CR 03140045	1-HV-AES-2 Backdraft Damper Failed to Seat Properly After Stopping the Fan.	May 20, 2003
CR 03140058	Switchgear CRID Area Intake Damper Reported to Be Oscillating. Actuator Positioner Adjustment Required.	May 20, 2003

<u>1R17</u> <u>Permanent Plant Modifications</u>

12-QHP-5050-NDE-005	Visual Weld and Brazing Examination	Revision 1
12-QHP-5050-NDE-002	Magnetic Particle Examination	Revision 2
01-MOD-35447-R0	Repair/Replace the CCW Heat Exchanger (1-HE-15E and W) Channel Head Divider Plate	Revision 0
2-LDCP-5452	Rewire Unit 2 Control Group and WSI Cabinet 24 Volt Power Supplies	Revision 0
2-TM-03-11-R0	Temporary Modification: Jumper Terminals to Bypass a Bistable for Pressure Interlock for Pressurizer PORVs and Trip VCT Low Level Logic to Support Unit 2 Control Group and WSI Cabinet 24 Volt Power Supplies	February 7, 2003
2-MOD-35590	Modification: Control Group/WSI and RPS Loss of Power Supply Redundancy Alarm	April 21, 2003
MD-12-ESW-101-N	CCW Heat Exchanger Partition Plate Modification Evaluation	Revision 0
Job Order 03124006-05	1-HE-15W, Replace Channel Head Divider Plate	May 10, 2003
CR 03126016	The Channel Cover (Dollar Plate) Pass Partition Groove on the Unit 1 West CCW Heat Exchanger (1-HE-15W) is Deteriorated.	May 6, 2003

CR 03128008	Final Weld Examination Rejected Visually.	May 8, 2003

1R19 Post Maintenance Testing

PMP-2291-PMT-001	Work Management Post Maintenance Testing Matrices	Revision 4
12-MHP-4030-032-046	Emergency Diesel Generator System 18-Month Inspection	Revision 4
02-OHP-4030-STP-052W	West Centrifugal Charging Pump Operability Test, Attachment 1	Revision 11
DIT-S-01145-00	Design Information Transmittal for Emergency Diesel Generator Testing	November 5, 2002
Job Order R0036964-04	Inspect Tank for Degradation per TIP Program	June 4, 2003
Job Order R0056279-02	Perform MOV Preventive Maintenance on 1-CMO-416	April 2, 2003
Job Order R0075141-01	1-CMO-414, Perform Preventive Maintenance	April 2, 2003
Job Order 02058038-07	Perform Operability Test for the West Centrifugal Charging Pump	May 31, 2003
Job Order 02058038-11	2-PP-50W, PMT for Instruments and Alarms	May 31, 2003
Job Order 0315066-02	2-CS-300 External Leak Check (PMT)	June 4, 2003
Job Order R0210337-01	1-CMO-420-ACT, Perform MOV Preventive Maintenance	April 2, 2003
Job Order R0221086-10	2-OME-150-CD, Perform 18 Month Diesel Surveillance	June 4, 2003
Job Order R0221086-11	2-OME-150-CD, Perform 18 Month Diesel Surveillance	June 4, 2003
Job Order R0226281-01	Perform Auxiliary Feedwater Flow Balance Test	June 4, 2003
Job Order R0234152-04	2-HE-47-CDS Clean/Inspect/Test After Cooler	June 4, 2003
Job Order 01252005-01	2-OME-150-CD, Repair Oil Leak on #1FB 4 Bolt Cover	May 29, 2003

Job Order 03140044-05	2-LDCP-5564 / PMT 2-DGCD-VRCKT After Replacement	June 10, 2003
Job Order 03135016-03	2-CMM-30030, 2-QT-131-CD Replace Tube Bundle	June 4, 2003
Job Order 03135016-08	2-CMM-30030, 2-QT-131-CD Replace Tube Bundle	June 3, 2003
12-IHP-5030-EMP-001	Limitorque Valve Operator Preventive Maintenance	Revision 5
02-EHP-4030-203-208	Unit 2 ECCS [Emergency Core Cooling System] Flow Balance - Boron Injection System	Revision 1
CR 02039004	During PMT Run of the 2CD EDG, It Had to Be Stopped After 1 Minute Due to Speed Cycling.	February 8, 2002
CR 02073024	The Diesel Generator PMT Described in PMP-2291-PMT-001 Contains Tests Not Performed at Cook, Is Excessive, and Would Require an Operating Unit to Shutdown to Mode 5.	March 14, 2002
CR 02080039 (1)	PMT Specified in Job Order 02039004 Following Replacement of the 2CD EDG Governor Hydraulic Actuator Did Not Contain All the Specified PMT Requirements of Attachment 1 of PMP-2291-PMT-001.	March 21, 2002
CR 02283062 (1)	NRC Inspector Questioned Adequacy of the PMT for the EDG Governor Replacement.	October 10, 2002
CR 03092074	During MOV PMT the Motor Run Current for 1-CMO-413 and 1-CMO-414 Was Above the Nameplate Value.	April 2, 2003

1R20 Refueling and Outage Activities

01-OHP-4021-001-001	Plant Heatup From Cold Shutdown to Hot Standby	Revision 31
01-OHP-4021-001-004	Plant Cooldown From Hot Standby to Cold Shutdown	Revision 39
01 OHP 4021-017-002	Placing In Service the Residual Heat Removal System	Revision 16

01-OHP-4030-114-030	Daily and Shiftly Surveillance Checks	Revision 2
01-OHP-4021-001-002	Reactor Startup	Revision29
02-OHP-4021-001-001	Plant Heatup From Cold Shutdown to Hot Standby	Revision 28
02-OHP-4021-001-004	Plant Cooldown From Hot Standby to Cold Shutdown	Revision 28
02 OHP 4021-017-002	Placing In Service the Residual Heat Removal System	Revision 13a
02-OHP-4030-214-030	Daily and Shiftly Surveillance Checks	Revision 1
12-OHP-4050-FHP-001	Refueling Procedure Guidelines	Revision 4
12-OHP-4050-FHP-005	Core Unload/Reload and Incore Shuffle	Revision 3a
02-OHP-4030-227-041	Refueling Integrity	Revision 0
02-OHP-4021-001-002	Reactor Startup	Revision24
12-EHP-4030-002-356	Low Power Physics Tests with Dynamic Rod Worth Measurement	Revision 0c
PMP 4100-SDR-001	Plant Shutdown Safety and Risk Management	Revision 5a
NRC Bulletin 2003-01	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors	June 9, 2003
	Shift Manager’s Logs	April 25, 2003 through June 19, 2003
	U2C14 Refueling Outage Schedule Shutdown Risk Review	May 9, 2003
	Unit 2 Mode Constraint List	June 11, 2003 06:57 a.m.
	U1F03B Forced Outage Schedule Shutdown Risk Review	May 9, 2003
CR 03050017	The Method of Isolating the Boron Injection Tank for Low Temperature Over-Pressure in Mode 4 Does Not Allow Restoration of Emergency Core Cooling System Flow Within 10 Minutes.	February 19, 2003

CR 03134052	Discrepancy Exists Between Procedures PMP-4030-001-002 Ventilation Requirements and 1(2)-OHP-4030-227-041 Refueling Integrity.	May 14, 2003
CR 03159006	Both CCPs in Unit 2 Were Racked In For 21 Minutes and Operated in Parallel for 7 Minutes. This is not Allowed by ECP 12N1-24.	June 8, 2003
CR 03161082	Apparent Configuration Deficiencies in the Unit 2 Containment Sump.	June 10, 2003
CR 03163038	NRC Identified a Paint Brush Head in the Ice Condenser Following the Final Cleanliness Inspection.	June 12, 2003

1R22 Surveillance Testing

02-OHP-4030-232-217A	DG2CD Load Sequencing and ESF Testing	Revision 5
02-OHP-4030-STP-017T	Turbine Driven Auxiliary Feedwater System Test	Revision 15a
02-OHP-4021-056-002	Auxiliary Feedwater Pump Operation	Revision 13a
OP-12-5137A-24	Flow Diagram: Waste Disposal System Vents and Drains Unit No. 1 and 2, Sheet 2 or 2	Revision 24
OP-1-5128-21	Flow Diagram: Reactor Coolant Unit No. 1, Sheet 1 of 2	Revision 21
OP-2-5128-22	Flow Diagram: Reactor Coolant Unit No. 2, Sheet 1 of 2	Revision 22
OP-1-5128A-45	Flow Diagram: Reactor Coolant Unit No. 1, Sheet 2 of 2	Revision 45
OP-2-5128A-51	Flow Diagram: Reactor Coolant Unit No. 2, Sheet 2 of 2	Revision 51
OP-1-5129-45	Flow Diagram: CVCS - Reactor Letdown and Charging Unit No. 1, Sheet 1 of 2	Revision 45
OP-2-5129-39	Flow Diagram: CVCS - Reactor Letdown and Charging Unit No. 2, Sheet 1 of 2	Revision 39
OP-1-5129A-28	Flow Diagram: CVCS - Reactor Letdown and Charging Unit No. 1, Sheet 2 of 2	Revision 28

OP-2-5129A-32	Flow Diagram: CVCS - Reactor Letdown and Charging Unit No. 2, Sheet 2 of 2	Revision 32
NRC Information Notice 94-46	Non-Conservative Reactor Coolant System Leakage Calculation	June 20, 1994
DIT-B-02702-00	Qualification of Safety Injection Accumulator Leakage into Reactor Coolant Drain Tank	April 26, 2003
12-EHP-4030-056-218	Automatic Operation of Auxiliary Feedwater Pumps	Revision 0
Job Order R0226340-01	Perform 12-EHP-4030-056-218	June 13, 2003
CR 02305080	2-MRV-233 Stroked Faster Than Its Inservice Testing Minimum Stroke Time.	November 1, 2002
CR 03065052	Review of CR03045053 Regarding Sticking Open of 12-ZRV-401 Has Determined a Possibility that the East Diesel Driven Fire Pump May Be Inoperable.	March 6, 2003
CR 03125006	Pressurizer Spray Valve 2-NRV-163 Is Stroking Too Slow as Observed in the Control Room.	May 5, 2003
CR 03160038	During the Performance of 12-EHP-4030-056-218, Automatic Operation of Auxiliary Feedwater Pumps, Steps Related to Recording the Time of the Measured Parameters and Stopping the Test Recorder Were Found to Not Be User Friendly.	June 9, 2003
CR 03161002	Trip of the West Centrifugal Charging Pump During 12-EHP-4030-056-218.	June 10, 2003
CR 03163026	Scheduled Replacement of 2-FFI-230 Has Passed its Drop Dead Date Without Being Completed.	June 12, 2003
CR 03168041	Inappropriate Actions Performed Prior to CR 03161036 Condition Evaluation.	June 17, 2003
CR 03169013	Technical Data Book 2-Figure 19.8, Revision 26, Was Updated Incorrectly	June 18, 2003

1R23 Temporary Modifications

12-EHP-5040-MOD-001	Temporary Modifications	Revision 10

PMP-2350-SES-001	10 CFR 50.59 Reviews	Revision 1
Welding Procedure Specification 1.2TS	Manual Gas Tungsten Arc and Shielded Metal Arc Welding	Revision 2
12-TM-01-14-R0	On-line Leak Sealing of Turbine Room Sump Overflow Pipe	Revision 0
1-TM-03-05-R0	Temporary Modification: Heater Drain Pump Trip on Unit 1 Turbine Trip	February 1, 2003
2-TM-03-22-R0	Temporary Modification: 2-QMO-225 Temporary Power Supply	April 10, 2003
2-TM-03-45-R0	Temporary Modification: Removal of CCW Flow to 2-CPN-2 Inner Cooling Coil	June 11, 2003
DIT-B-02743-00	Discussion of Analyzed Design Basis Configuration for the CPN-2 Penetration	June 8, 2003
02-OHP-4030-208-053A	ECCS Valve Operability Test - Train A	Revision 0a
02-OHP-4030-214-034	Local Valve Position Verification Test	Revision 1a
Job Order 01153021-01	Repair Leak on 30 Inch Line Downstream of 12-DR-130	May 12, 2003
Job Order 01153021-02	Post Maintenance Test Repaired Leak on 30 Inch Line Downstream of 12-DR-130	May 12, 2003
Job Order 01153021-05	Repair Welds on 6 Inch to 30 Inch Weld and Mitered Joint	May 12, 2003
Job Order 01153021-06	Complete Leak Repair on 30 Inch Line Downstream of 12-DR-130	May 12, 2003
Job Order 01161003	Repair Leak on 30 Inch Line 60 Feet Downstream of Valve 12-DR-130	May 3, 2003
CR 03121037	An Unidentified Support on the 30 Inch Turbine Room Sump Emergency Overflow Line Has Cracked Welds.	May 1, 2003
CR 03126036	While Performing an Inspection Inside the Existing 30 Inch Drain Piping that Comes from the Turbine Room Sump, Over 40 Degraded and Potential Repair Locations Were Found.	May 6, 2003

CR 03168039	NRC Identified That Job Order 01153021-05 Had Step 5.1 and 5.2 of the Job Order Task Description Not Applicable. Job Order 01153021-065 Weld Data Sheet for OW-1 and OW-4 Incorrectly Referenced Material Thickness as 30".	June 17, 2003

<u>2OS1</u> <u>Access Control to Radiologically Significant Areas</u>

RWP 03-3002	Forced Outage Containment Entry	Revision 0
RWP 03-3001	Forced Outage and Locked High Radiation Area Entry	Revision 0

<u>2OS2</u> <u>ALARA Planning and Controls</u>

12-THP-6010-RPP-006	Radiation Work Permit Processing	Revision 17
PMP-6010-ALA-001	ALARA Program - Review of Plant Work Activities	Revision 11
12-THP-6010-RPP-018	Controls for Radiological Risk Significant Work Activities	Revision 1
12-THP-6010-RPP-014	Total Effective Dose Equivalent Evaluation	Revision 3a
12-THP-6010-RPP-405	Analysis of Airborne Radioactivity	Revision 6
12-THP-6010-RPP-401	Performance of Radiation and Contamination Surveys	Revision 11
12-THP-6010-RPP-007	Exhibit A: TEDE Evaluation Conversion Factors - RP Calculation 96-07	Revision 0
12-THP-6010-RPP-007	Exhibit A: TEDE Evaluation Alpha Conversion Factors - RP Calculation 97-15	Revision 0
Radiation Work Procedure (RWP) 03-2106	U2C14 CRDM Head Inspections	Revision 0
RWP 03-2126	U2C14 Scaffold Erection/Removal in Auxiliary Building and Plant Restricted Areas	Revision 0
RWP 03-2142	U2C14 - Containment Building, Install, Modify and Remove Scaffolding	Revision 0

RWP 03-2151	U2C14 - Reactor Coolant Pump Seal Maintenance Activities	Revision 0
RWP 03-2190	U2C14 - Design Change Process No. 5194, Steam Generator Platform Installation	Revision 0
RWP 03-2191	U2C14 - Design Change Process No. 5326, Permanent Shielding	Revision 0
	U2C14 RWP and Dose Projection Listing	
	U2C14 Refueling Outage Schedule; Level 1 Logic Diagram and Level 2 Outage Windows	Revision C
	Listing of ALARA Review Committee and Subcommittee Members and Selected Meeting Minutes	February 2003
THG-024	RP Actions for Induced CRUD Burst	Revision 1b
	U2C14 Remote Monitoring Locations (CRUD Burst)	
	D. C. Cook Nuclear Power Plant Dose Reduction 5-Year Plan 2003	
	U1C18 Outage ALARA Report - Unit 1 Refueling Outage	May 2002
	U2C13 Outage ALARA Report; Unit 2 Refueling Outage	January 2002
12-THP-6010-RPP-121	Dose Monitoring for Declared Pregnant Woman	Revision 01
PMP-6010-RPP-100	Radiation Exposure Monitoring, Reporting, and Dose Control - Declaration Forms	January 2002 through March 2003
12-THP-6010-RPP-121	Dose Monitoring for Declared Pregnant Woman, Data Sheet No. 1	January 2002 through March 2003

4OA1 Performance Indicator (PI) Verification

NEI 99-02	Regulatory Assessment Performance Indicator Guideline	Revision 2
Special Plant Procedure 2060-SFI-101	PI Data Gathering	Revision 0
PMP 7110.PIP.001	Regulatory Oversight Program PI	Revision 1

12-THP-6020-CHM-101	Reactor Coolant System	Revision 14c
12-THP-6020-CHM-101	Data Sheet 4; Dose Equivalent Iodine Determination	December 2002 through April 9, 2003
12-THP-6020-INS.527	Gamma Spectrometry Using Genie 2000 and Procount	Revision 0
Letter from J. Pollock, American Electric Power, to the US NRC	D. C. Cook Unit 1 and 2 -- 4Q2002 -- PI Data Elements (QR and CR)	January 21,2003
Letter from J. Pollock, American Electric Power, to the US NRC	D. C. Cook Unit 1 and 2 -- 3Q2002 -- PI Data Elements (QR and CR)	October 21, 2002
Letter from J. Pollock, American Electric Power, to the US NRC	D. C. Cook Unit 1 and 2 -- 1Q2003 -- PI Data Elements (QR and CR)	April 21, 2003

<u>4OA2 Identification and Resolution of Problems</u>

CR 02133002	Unit 2 Trip from 100 Percent Power Due to Low Feedwater Flow Coincident with Low Steam Generator Level on Loop 1.	May 12, 2002
CR 02325058	Weekly Recurring Tasks to Walkdown Taylor Mod 30 Power Supplies - No Documented Performance of Walkdown Since September 30, 2002.	November 21, 2002
CR 03014036	Inadequate Action in CR 02133002-006.	January 14, 2003
CR 03038002	Incorrect Information Transmitted in LER 50-316/2002-005-00.	February 6, 2003

<u>4OA3 Event Followup</u>

LER 316-2003-002-00	Unit 2 Trip Due to Instrument Rack 24-Volt DC Power Supply Failure	April 7, 2003
LER 316-2002-005-00	Unit 2 Trip Due to Instrument Rack 24-Volt DC Power Supply Failure	July 10, 2002
NRC Information Notice 94-24	Inadequate Maintenance of Uninterruptible Power Supplies and Inverters	March 24, 1994
NRC Information Notice 95-10, Supplement 2	Potential for Loss of Automatic Engineered Safety Features Actuation	August 11, 1995

NRC Event Notification 39564	D.C. Cook Unit 2 Tripped From Full Power Due to an Instrument Rack Power Supply Failure	February 6, 2003
PMP 4010.TRP.001	Unit 2 Reactor Trip Review Report	February 6, 2003
	Unit 2 Control Room Logs	February 5, 2003 through February 6, 2003
CR 01236037	There Have Been a Significant Number of Electronic DC Power Supply Failures During the Past 24 Months.	August 24, 2001
CR 02047020	2-CG-2-19 Power Supply PS2 Power Available Lamp Is Off.	February 16, 2002
CR 02133001	Both 24-Volt DC Power Supplies in Control Group 1 for Rack 16 Failed.	May 12, 2002
CR 02133002	Unit 2 Trip From 100 Percent Due to Low Feedwater Flow Coincident With Low Steam Generator Level on Loop 1.	May 12, 2002
CR 03036056	Unit 2 Reactor Tripped on Low Steam Generator Level Coincident with Steam Flow/Feed Flow Mismatch Due to Control Group 3, Dual Power Supply Failure.	February 5, 2003
CR 03037028	Excessive Unit 2 RCS Cooldown After Trip from 100 Percent Power.	February 5, 2003
CR 03038002	Incorrect Information Transmitted in LER 316-2002-005-00.	February 7, 2003
CR 03040016	Excessive Voltage Drop on Control Group 4 24-Volt Power Supply Leads Indicates Undersized Wiring Between Power Supply Drawer and Cabinet.	February 9, 2003
CR 03043007	Power Supply Failures Have Contributed to Reactor Trips and Unit Unavailability.	February 12, 2003
CR 03083050	The Evaluation Performed to Support Both the Most Recent Control Group Power Supply Failures and the May 2002 Failure Did Not Sufficiently Address the Coincident Failure of These Power Supplies.	March 24, 2003
LER 50-316/2002-007-00	Technical Specification 3.8.1.1 Allowed Outage Time Exceeded	December 13, 2002

LER 50-316/2003-001-00	Unit 2 Shutdown in Accordance with Technical Specification 3.8.1.1, A.C. Sources, Action b	December 13, 2002
NRC Event Notification 39790	D. C. Cook Dual Unit Trip and Alert Declared Due to Influx of Fish and ESW System Challenges	April 24, 2003
	Shift Manager's Logs	April 24, 2003 through April 26, 2003
Letter from A. C. Bakken, American Electric Power, to the US NRC	Donald C. Cook Nuclear Plant Units 1 and 2 Response to April 24, 2003 Fish Intrusion Event	April 28, 2003
LER 50-315/1999-023-00	Inadequate Technical Specification Surveillance Testing of ESW Pump ESF Response Time	October 7, 1999
LER 50-315/1999-023-01	Retraction of LER 50-315/1999-023-00	October 3, 2000

4OA5 Other

LER 316-2002-007-00	Technical Specification 3.8.1.1 Allowed Outage Time Exceeded	December 13, 2002
Letter from Indiana Michigan Power to NRC AEP:NRC:2016-04	Donald C. Cook Nuclear Plant Unit 2, Request for Notice of Enforcement Discretion from TS 3.8.1.1 Limiting Condition for Operation for the CD Emergency Diesel Generator	November 6, 2002
Letter from NRC to Indiana Michigan Power	Notice of Enforcement Discretion for Indiana Michigan Power Company Regarding D. C. Cook, Unit 2 (NOED 02-3-058)	November 8, 2002
	Operations Night Orders	November 5, 2002
02-3977	Cook Plant Operations Review Committee Minutes	November 4, 2002
	Daily Shift Manager's Logs	November 2, 2002 through November 4, 2002
CR 02306005	CD EDG Exhibited 150 kW Oscillations at Full Load During Surveillance Testing	November 2, 2002
CR 02315096	Spare EGM Module Failed to Function After Installation	November 4, 2002

CR 02315097	Incorrect Setting of Temperature Control Valve Delayed Limiting Condition for Operation	November 4, 2002
CR 02315099	Spare Governor Oil Level Lost During Limiting Condition for Operation on 2-OME-150-CD	November 4, 2002
CR 02316069	Remove Cover and Inspect Internals of EGM Module to Determine if the Module Contains an Electrolytic Capacitor	November 5, 2002

1R08 Inservice Inspection Activities

Audit

Performance Assurance Department Audit Report dated November 8, 1999

Condition Reports

01241027; 1RC-102-L2 Has A Buildup Of Boric Acid Indicating A Packing Leak Or Bonnet Leak; dated August 29, 2001

02023050; Unit 2 Third Period Second Interval Exam Code Relief Requests Had Not Been Submitted As Required By 10 CFR50.55a; dated January 23, 2001

02141047; During U1C18 Steam Generator Eddy Current Inspections 4 Tubes Were Identified With Abnormal Eddy Current Signals; dated May 21, 2002

02035046; During The 2002 NRC ISI Inspection, The NRC Inspector Raised The Following Questions On The Possible Inaccurate Application Of Weld Acceptance Criteria; dated February 4, 2002

02035044; The NRC Inspector Has Raised The Following Questions During The 2002 ISI Inspection; dated February 4, 2002

02207026; Tracking eSat To Follow Review Of Abnormal Steam Generator Eddy Current Signals Noted During U1C18 Steam Generator Inspection; dated July 26, 2002

02174018; Unit 1 Steam Generator Contaminates Increased Following The Middle Hotwell Pump Start; dated June 23, 2002

Corrective Action Process Reports Issued As a Result of Inspection Activities

3135023; Historic Failure To Identify Source Of Leakage When Boric Acid And Corrosion Were Found On The Bottom Of Unit 2 Reactor Vessel During The Bottom Head Inspection; dated May 14, 2002

Code Replacement/Repair Activities

Job Order 0124102706; 1-RC-102-L2 Replace Valve EE-2002-0340; dated May 19, 2002

Job Order R005877514; 2-PP-50W Remove/Install Piping To Support Repairs; dated January 31, 2002

Nondestructive Examination Reports

Radiographic record for 6 inch diameter charging pipe-to-nozzle weld 2CS81OW-1R3; dated February 8, 2002

325500; Valve To Elbow Weld 2-SI-42-01S Dye Penetrant Examination Report; dated May 8, 2003

325500; Valve To Elbow Weld 2-SI-42-01S Ultrasonic Examination Report; dated May 8, 2003

325520; Pipe To Valve Weld 2-SI-42-03F Dye Penetrant Examination Report; dated May 9, 2003

325520; Pipe To Valve Weld 2-SI-42-03F Ultrasonic Examination Report; dated May 9, 2003

329100; Pipe To Elbow Weld 2-SI-72-11S Dye Penetrant Examination Report; dated May 8, 2003

329100; Pipe To Elbow Weld 2-SI-72-11S Ultrasonic Examination Report; dated May 8, 2003

001800; Reactor Vessel To Flange Weld 2-RPV-A; Ultrasonic Examination Report dated May 12, 2003

Procedures

54-ISI-130-38; Ultrasonic Examination Of Ferritic Vessel Welds Greater Than 2.0 Inches In Thickness; Revision 38

54-ISI-124-02; Ultrasonic Examination Of Ferritic Piping Welds And Vessel Welds Two Inches Or Less In Thickness; Revision 2

54-ISI-835-04; Procedure For The Ultrasonic Examination Of Ferritic Piping Welds; Revision 4

54-ISI-836-04;Procedure For The Ultrasonic Examination Of Austenitic Piping Welds; Revision 4

54-ISI-837-03;Procedure For The Ultrasonic Through-Wall Sizing In Pipe Welds; Revision 3

54-ISI-240-40; Visible Solvent Removable Liquid Penetrant Examination Procedure: Revision 40

54-ISI-270-39; Wed Or Dry Magnetic Particle Examination Procedure; Revision 39.

Miscellaneous Documents

Weld Procedure Specification 8.1TS; dated May 13, 2002

Procedure Qualification Record 136; dated February 10, 1976

Procedure Qualification Record 219; dated January 16, 1990

Procedure Qualification Record 256; dated August 7, 1989

Procedure Qualification Record 258; dated August 7, 1989

Weld Procedure Specification 1.2TS; dated March 10, 2000

Procedure Qualification Record 136; dated February 10, 1976

Procedure Qualification Record 234; dated March 29, 1989

Procedure Qualification Record 235; dated March 30, 1989

Procedure Qualification Record 255; dated August 8, 1989

TI 2515/150 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles

Corrective Action Documents

CR 03026011; 2-RC-121-Dry Boric Acid From An Old Packing Leak; dated January 26, 2003

CR 03138024; Craze Cracking Has Been Discovered On Penetrations 43, 59 And 64; dated May 18, 2003

CR 031370448; Cracks Found On The Inside Diameter Of Penetration 74 During The Unit 2 Reactor Head Inspection Have Been Evaluated As Not Serviceable For The Next Cycle; dated May 15, 2003

CR P-00-06663; CETNA Seal #4 Leaking RCS From Swagelock Fittings; dated May 9, 2000

eSAT-02055022; Numerous Components Have Accumulated Boric Acid; dated February 24, 2002

eSAT-03137028; Rust Staining Was Noted At Penetration Annular Area And Trailing Down The Head Surface; dated May 17, 2003

CR 03143045; Unit 2 RPV Penetration # 73 Has An Area Below The Weld That Cannot Be Inspected By TOFD UT Or ET; dated May 22, 2003

Corrective Action Process Reports Issued As a Result of Inspection Activities

CR 03148059; Three Documentation Issues Related To Determination Of The Susceptibility Category Of The Unit 2 Reactor Vessel Head Were Identified; dated May 28, 2003

eSAT-03143034; Specific Dimensions Related To Tooling And Probes For The Westinghouse Eddy Current Gap Scanner; dated May 22, 2003 eSAT-03143035; Formal Documentation Describing The Westinghouse Eddy Current Gap Scanner Detection Capabilities Was Not Available; dated May 22, 2003

eSAT-03143036; Formal Documentation Describing The Westinghouse Eddy Current Array Detection Capabilities Was Not Available; dated May 22, 2003

CR 3143038; Reference To The Plant Specific Head Temperature Is Not Documented In The MRP Guidance; dated May 22, 2003

Design Information Transmittals

DIT B-02726-00; Unit 1 & 2 Effective Degradation Years; dated May 14, 2003

DIT S-00700705-03; Unit 1And Unit 2 Burnup Data; dated April 29, 2003

Drawings

6D30089; RV Head Penetration CRDM Calibration Standard CRDM Calibration Standard Details; Revision 0

CBI 19; 173" Instrumentation Tube Final Machining Details; Revision 9

CBI 21; Instrumentation Tube Installation Details 173" PWR; Revision 10

CBI 23; Location Of Instrumentation Tubes In Bottom Head 173" PWR; Revision 2

CBI 38; 173" PWR Top Head Assembly; Revision 4

CBI 40; CRD Housing Installation Detail 173" PWR; Revision 12

CBI 41; 173" PWR Control Rod Drive Mechanism Housings Final Machining Details; Revision 13

CBI 52; 173" Location Of Control Rod Drive Mechanism Housings In Top Head ~ (Outside View); Revision 6

Miscellaneous Documents

MRP-48; PWR Materials Reliability Program Response To NRC Bulletin 2001-001; dated August 2001

Westinghouse WIN 284-6397; Upper Head Temperatures For Westinghouse Plants Based On Plant Operating Data Survey; dated November 4, 1992

Order EA-03-009; Issuance Of Order Establishing Interim Inspection Requirements For Pressure Vessel Heads At Pressurized Water Reactors; dated February 11, 2003

AEP Letter NRC 3054-03; Donald C. Cook Nuclear Plant Units 1And 2 Answer To Nuclear Regulatory Commission Order Establishing Interim Inspection Requirements For Reactor Pressure Vessel Heads At Pressurized Water Reactors; dated March 3, 2003

AEP Letter NRC 3054-04; Donald C. Cook Nuclear Plant Units 1 And 2 Request For Relaxation From Nuclear Regulatory Commission Order Establishing Interim Inspection Requirements For Reactor Pressure Vessel Heads At Pressurized Water Reactors; dated March 26, 2003

AEP Letter NRC 3054-06; Donald C. Cook Nuclear Plant Units 1And 2 Response To Request For Additional Information Regarding Relaxation Of Reactor Pressure Vessel Head Penetration Inspection Requirements In Nuclear Regulatory Commission Order; dated May 13, 2003

NRC Letter (package ML030980327); Flaw Evaluation Guidelines; Dated April 11, 2003.

Job Order R0073019; Perform Full Pressure Temperature Walkdown; dated June 17, 2000

Job Order R0204062; Perform Full Pressure Temperature Walkdown; dated February 24, 2002

Job Order 02294028; 2-OME-1 Repair Rx Vessel Head Penetration 74 & 43; dated May 31, 2003

Letter from P. Lara (EPRI) to R. Hall (AEP); dated May 23, 2003

WCAP-14563; Determination Of Maximum Excavation Depth On Reactor Head Penetrations For D.C. Cook Units 1 &2; Revision 0

PCI Project Instruction PI-900073-12; RVHP EDM Defect Removal Tool For Nozzle Inside Diameter Operation; Revision 1

Letter AEP-03-48; Sensitivity Study Information For Unit 2 Relaxation Request, from R. Rice (Westinghouse) to C. Bakken (AEP); dated June 2, 2003

AEP Letter; Best Estimate Hot Leg Temperature For Donald C. Cook Plant Unit 1 and Unit 2; dated July 1, 1997

AEP Letter; Best Estimate Hot Leg Temperature For Donald C. Cook, Unit 2; dated July 21, 1994

EPRI Letter from B. Rassler (EPRI) to R. Hall (AEP); dated June 4, 2003

Wesdyne International; Blade And Open Housing UT Essential Variables; dated September 2002

Wesdyne Report; Leak Path Detection; March 2003.

WDI-TJ-008-03;Sysem Setup Testing Of Blade Probe For Multiple Inspection Sensitivities; Revision 0 and Revision 1

WDI-TJ-002-02; Technical Justification For Eddy Current Of J-Groove Welds; Revision 0

EPRI Materials Reliability Project Report; Dated December 11, 2002.

WDI-TJ-007-03; Installation of High Pass Filter To Improve Blade Probe Inspections; Revision 0

WDI-TJ-013-02; MRP Inspection Demonstration Program; dated December 2, 2002

Nondestructive Examination Reports

Liquid Penetrant Examination Report; Rx Hd Vent Under Vessel J-Weld And ID Chamfer (Job Order 02294028-06); dated May 21, 2003

Liquid Penetrant Examination Report (Job Order 02294028-06); RX Head Penetration # 73 Threaded End And ½" Above; dated May 30, 2003

Liquid Penetrant Examination Report (Job Order 02294028-06); RX Head Penetration # 75 J-Weld And Penetration, dated May 24, 2003

Liquid Penetrant Examination Report (Job Order 02294028-06); RX Head Penetration # 75 J-Weld Re-examination area, dated May 31, 2003

DCC-002; Report of Non-Destructive Examination Liquid Penetrant, Penetration #74 ID, dated June 2, 2003

DCC-001; Report of Non-Destructive Examination Liquid Penetrant, Penetration #43 ID, dated June 2, 2003

Eddy Current Report Sheet; Penetration No. 74; dated May 15, 2003

Eddy Current Report Sheet; Penetration No. 43; dated May 18, 2003

Eddy Current Report Sheet; Penetration No. 59; dated May 18, 2003

Eddy Current Report Sheet; Penetration No. 64; dated May 18, 2003

Eddy Current Report Sheet; Penetration No. 59; dated June 4, 2003

Eddy Current Report Sheet; Penetration No. 64; Dated June 4, 2003

Eddy Current Report Sheet; Penetration No. 43; dated June 2, 2003

Eddy Current Report Sheet; Penetration No. 74; dated June 2, 2003

Eddy Current Report Sheet; Penetration No. 74; dated May 2, 2003

Ultrasonic Report Sheet; Penetration No. 74; dated May 15, 2003

Draft Visual Examination Records MRS-SSP-1483-AMP, Appendix D; dated May 14, 2003 through May 16, 200.

Procedures

02-0HP-4030-001-002; Containment Inspection Tours; Revision 14

PMP-5030-001-001; Boric Acid Corrosion of Ferritic Steel Components and Material, Revision 5

12-QHP-5070-NDE-001; Visual VT-2 Examination: RCS System Leakage Test; Revision 2a

12-QHP-5050-NDE-027; Visual Examination For Boric Acid And Condition Of Component Surfaces; Revsion 0

GQP 9.4; Remote Flourescent Post-Emulsifiable Dye Penetrant Exam and Acceptance; Revision 2, Change 0

MRS-SSP-1483-AMP; Rx Vessel Head Penetration Remote Visual Inspections For D. C. Cook Unit 2; Revision 1, Change 0

WDI-ET-002; IntraSpect Eddy Current Inspection Of J-Groove Welds in Vessel Head Penetrations; Revision 2, Field Change Notice 2

WDI-UT-010; IntraSpect Ultrasonic Procedure For Inspection Of Rx Vessel Head Penetrations/Time Of Flight Ultrasonic, Longitudinal Wave & Shear Wave; Revision 4, Field Change Notice 5

WDI-UT-011; IntraSpect NDE Procedure For Inspection Of Reactor Vessel Head Vent Tubes," Revision 2; Field Change Notice 2

WDI-UT-013; CRDM/ICI UT Analysis Guidelines; Revision 2, Field Change Notice 3

WDI-ET-004; IntraSpect Eddy Current Analysis Guidelines Inspection Of Reactor Vessel Head Penetratios; Revision 2, Change 1

WDI-ET-003; IntraSpect Eddy Current Imaging Procedure For Inspection Of Reactor Vessel Head Penetrations; Revision 4, Change1

WDI-ET-008; IntraSpect Eddy Current Imaging Procedure For Inspection Of Rx Vessel Head Penetrations With Gap Scanner; Revision 1, Field Change Notice 1 and Field Change Notice 2

WDI-STD-101; RVHI Vent Tube J-Weld Eddy Current Examination; Revision 0, Change 0

MRS-SSP-1484-AMP; Reactor Vessel Head Penetration Repair Scenarios For D.C. Cook Unit 2; Revision 0, Field Change Notice 1

LIST OF ACRONYMS USED

ADAMS	Agency-wide Documents and Management System
ALARA	As-Low-As-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CVCS	Chemical Volume Control System
CY	Calender Year
DC	Direct Current
DIT	Design Information Transmittal
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
EFPY	Effective Full Power Years
EGB	Governor Hydraulic Actuator
EGM	Electronic Governing Module
EHP	Electrical Maintenance Head Procedure
EP	Emergency Preparedness
EPRI	Electrical Power Research Institute
eSAT	Electronic Single Action Tracking
ESF	Engineered Safety Feature
ESW	Essential Service Water
ET	Eddy Current
FAQ	Frequently Asked Question
ICM	Interim Compensatory Measures
IHP	Instrument Maintenance Head Procedure
IMC	Inspection Manual Chapter
IST	Inservice Testing
KW	Kilowatts
LER	Licensee Event Report
LERF	Large Early Release Frequency
LCO	Limiting Condition For Operation
MHP	Maintenance Head Procedure
MS	Mitigating System
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NOED	Notice of Enforcement Discretion
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OA	Other Activities
OHP	Operations Head Procedure
OPR	Operability Recommendation

OWA	Operator Work-Arounds
PARS	Publically Available Records
PI	Performance Indicator
PMI	Plant Manager’s Instruction
PMP	Plant Manager’s Procedure
PORV	Power Operated Relief Valve
PT	Dye Penetrant
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RP	Radiation Protection
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SAI	Single Axial Indication
SDP	Significance Determination Process
SG	Steam Generator
SSC	Structures, Systems, and Components
STP	Surveillance Test Procedure
TEDE	Total Effective Dose Equivalent
TI	Temporary Instruction
TOFT	Time-Of-Flight-Tip-Diffraction
TRU	Transuranic Nuclide
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic
U2C14	14^{th} Unit 2 Refueling Outage
VHP	Vessel Head Penetration
WSI	Water System Indication