August 10, 2006

EA 03-009

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

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000315/2006004;
05000316/2006004 and 05000315/2006010; 05000316/2006010

Dear Mr. Nazar:

On June 30, 2006, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your D. C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection results, which were discussed on July 6, 2006, with Mr. M. Peifer 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, seven findings of very low safety significance (Green), were identified, five of which involved violations of NRC requirements. In addition, one Severity Level IV Non-Cited Violation of 10 CFR 50.73(a)(1) was identified. However, because of the very low safety significance and because the issues were entered into your corrective action program, the NRC is treating the violations as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector's Office at the D. C. Cook Nuclear Power Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (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 by Robert Lerch Acting for/

Christine A. Lipa, Chief
Reactor Projects Branch 4
Division of Reactor Projects

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

Enclosure: Inspection Report 05000315/2006004; 05000316/2006004 and 05000315/2006010; 05000316/2006010
w/Attachment: Supplemental Information

cc w/encl: M. Peifer, Site Vice President
L. Weber, Plant Manager
S. Simpson, Regulatory Affairs Manager
G. White, Michigan Public Service Commission
L. Brandon, Michigan Department of Environmental Quality - Waste and Hazardous Materials Division
Emergency Management Division
MI Department of State Police
State Liaison Officer, State of Michigan
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 Nos.:	05000315/2006004; 05000316/2006004 05000315/2006010; 05000316/2006010
Licensee:	Indiana Michigan Power Company
Facility:	D. C. Cook Nuclear Power Plant, Units 1 and 2
Location:	Bridgman, MI 49106
Dates:	April 1 through June 30, 2006
Inspectors:	B. Kemker, Senior Resident Inspector J. Lennartz, Resident Inspector A. Garmoe, Reactor Engineer J. Jandovitz, Reactor Inspector R. Jickling, Emergency Preparedness Analyst M. Jordan, NRC Contractor M. Phalen, Radiation Specialist F. Ramírez, Reactor Engineer N. Shah, Project Engineer
Approved by:	C. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000315/2006004, 05000316/2006004; IR 05000315/2006010, 05000316/2006010; 04/01/2006-06/30/2006; D. C. Cook Nuclear Power Plant, Units 1 and 2, Flood Protection, Personnel Performance During Non-Routine Evolutions and Events, Surveillance Testing.

The report covered a 13-week period of inspection by the resident inspectors and announced inspections by regional inspectors. One Severity Level IV Non-Cited Violation (NCV) and seven Green findings, five of which had an associated NCV, 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. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

C Green. The inspectors identified a finding of very low safety significance. The licensee failed to perform adequate preventive and corrective maintenance on Turbine Building sump overflow check valve 12-DR-129. As a result, the valve was found in a significantly degraded condition such that it would not function to mitigate the consequences of a design basis seiche event. No violation of regulatory requirements was identified. Immediate corrective actions to address this finding included replacing the check valve and implementing a preventive maintenance activity to ensure that it would function.

This finding was of more than minor significance because it was associated with the Protection Against External Factors attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations since inadequate preventive and corrective maintenance led to the significantly degraded condition of check valve12-DR-129. Although this issue affected the ability of the check valve to mitigate the consequences of a design basis seiche event, the Regional Senior Reactor Analyst determined that this finding was of very low safety significance during a Phase 3 SDP evaluation because considering the seiche initiating event frequency, the change in core damage frequency for this finding was calculated to be well below 1.0E-6. This finding affected the cross-cutting area of problem identification and resolution because the licensee failed to identify and correct the degraded valve condition. Corrective actions that were taken were not timely, were not commensurate with the significance of the issue, and early corrective actions were ineffective. (Section 1R06.b.2)

C Green. A finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" was self-revealed. With Unit 2 in Mode 4 (Hot Shutdown), using an inadequate procedure, plant operators performed procedural steps to vent the residual heat removal system piping while the system was still connected to the reactor coolant system (RCS). As a result, the charging pump suction safety valve 2-SV-56 unexpectedly lifted and discharged approximately 120 gallons of water to the pressurizer relief tank. Corrective actions included revising the procedures for placing emergency core cooling systems (ECCS) in standby readiness and an engineering evaluation was completed to ensure that the charging pump suction header piping did not exceed its design pressure.

This finding was of more than minor significance because it was related to the Procedure Adequacy attribute of the Initiating Events cornerstone, and adversely impacted the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown operations. Specifically, the finding resulted in an unintended loss of RCS inventory with the plant shut down in Mode 4. The finding was not greater than Green because adequate mitigation capabilities were maintained, and the finding did not represent a loss of control in that less than 2 feet of RCS inventory was lost from the pressurizer. The primary cause of this finding was related to the cross-cutting area of human performance because the procedure that was used was not complete. (Section 1R14.1)

Cornerstone: Mitigating Systems

C Green. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criteria III, "Design Control." The licensee failed to correctly translate the design basis into specifications for the essential service water (ESW) system by ensuring that ESW system components in the Lake Screen House would be protected to the 595' elevation as described in Section 10.6 of the Updated Final Safety Analysis Report, in the event of flooding due to a design basis seiche event. The licensee was evaluating corrective actions for this issue at the end of the inspection period. No immediate actions were necessary due to the present low lake level.

This finding was of more than minor significance because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences since the failure to maintain adequate design control for the affected ESW system components in the Lake Screen House could possibly have resulted in damage to safe shutdown plant equipment during a design basis seiche event. The finding was of very low safety significance because it was a design or qualification deficiency confirmed not to result in loss of operability. (Section 1R06.b.1)

- Green. The inspectors identified a finding of very low safety significance. The licensee did not adequately evaluate the functionality of Turbine Building sump overflow check valve 12-DR-129, while the valve was in a significantly degraded condition such that it would not function to mitigate the consequences of a design basis seiche event. No violation of regulatory requirements was identified. Immediate corrective actions to address this finding included a detailed calculation to determine the potential for flooding in the emergency diesel generator (EDG) rooms to support a past operability evaluation for the EDGs.

  This finding was of more than minor significance because if left uncorrected, the failure to properly evaluate the functionality of equipment important to safety could result in incorrectly concluding that the equipment was functional. The inspectors determined that this finding was related to the Protection Against External Factors attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Consistent with the Phase 3 SDP evaluation performed in Section 1R06.b.2, this finding was determined to be of very low safety significance. This finding affected the cross-cutting area of problem identification and resolution because the licensee did not apply appropriate rigor and detail to its evaluation of the non-functional check valve; and as a result, the potential impact on safe shutdown equipment was not evaluated and timely corrective actions were not taken. (Section 1R06.b.3)

- Green. The inspectors identified a finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criteria III. The licensee failed to establish appropriate Technical Specification (TS) surveillance acceptance criteria for full load rejection testing of the EDGs with its implementation of Improved Standard Technical Specifications. An emergency TS amendment was required to revise the acceptance criteria.

  This finding was of more than minor significance based on programmatic concerns identified with the issue that could lead to worse errors if not corrected. This finding was not suitable for an evaluation using the SDP, but has been reviewed by NRC management and was determined to be a of very low safety significance. The finding was determined not to be greater than Green because there was no actual adverse impact to plant equipment. This finding affected the cross-cutting area of human performance because the licensee did not apply appropriate rigor and detail to its evaluation of the new TS surveillance acceptance criteria; and as a result, the engines could not meet the criteria when tested. (Section 1R22.b.3)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance was self-revealed, when the lift rig device failed and a 37 ton vertical bulkhead block dropped approximately 15 feet inside Unit 2 containment with the plant in Mode 5 (Cold Shutdown). The plant procedure utilized did not require a load cell while lifting the vertical bulkhead blocks and therefore adequate detection of load binding was not provided. Consequently, load binding during the lift was not detected and the lift rig assembly was overloaded and failed.

  This finding was of more than minor significance because if left uncorrected, this issue could lead to a more significant safety concern in that a dropped heavy load could impact and adversely affect plant safety-related structures, systems or components. This finding was not suitable for an evaluation using the SDP, but has been reviewed by NRC management and was determined to be a finding of very low safety significance. This finding was not greater than Green because no adverse consequences to plant safety-related or risk significant structures systems or components resulted from the dropped load. The primary cause of this finding was related to the cross-cutting area of human performance because the procedure that was used was not complete. (Section 1R14.2)

- Green. The inspectors identified a finding of very low safety significance with an associated NCV of TS Surveillance Requirement 3.6.1.1. The licensee failed to perform an as-found local leak rate test (LLRT) for containment isolation valve 2-SI-189 (ECCS safety valves discharge to the primary relief tank containment isolation check valve) prior to performing maintenance that affected the valve's leak tightness as required by the plant's TSs. Immediate corrective actions to address this finding were to revise the planning and scheduling activities for testing this valve.

  This finding was of more than minor significance because it was associated with the Structure, System and Component (SSC) and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that the physical design barriers (e.g., containment) protect the public from radio-nuclide releases caused by accidents or events since the true as-found condition of 2-SI-189 for the previous operating cycle was unknown and could not be evaluated. This finding was of very low safety significance because Unit 2 was defueled at the time and containment integrity was not required. This finding affected the cross-cutting area of human performance because the licensee failed to properly sequence the valve's visual inspection activity after the as-found LLRT into its scheduling process. (Section 1R22.b.1)

- Severity Level IV. The inspectors identified an NCV of 10 CFR 50.73(a)(1) because the licensee failed to submit a required Licensee Event Report within 60 days after discovery of an event requiring a report. The event involved the licensee's failure to meet Containment Leakage Rate Testing Program requirements in accordance with TS Surveillance Requirement 3.6.1.1, a condition prohibited by the plant's TSs. No immediate corrective actions were taken to address this finding; however, the issue was entered into the licensee's corrective action program.

This finding was of more than minor significance because the NRC relies on licensees to identify and report conditions or events meeting the criteria specified in the TSs and the regulations to perform its regulatory function. Because the issue affected the NRC's ability to perform its regulatory function, it was evaluated with the traditional enforcement process. Consistent with the guidance in Section 7.10 and Supplement I, paragraph D.4 of the NRC Enforcement Policy, this issue was determined to be a Severity Level IV violation. This finding affected the cross-cutting area of problem identification and resolution because the licensee incorrectly evaluated the condition and concluded that the failure to perform an as-found LLRT for containment isolation valve 2-SI-189 was not a condition prohibited by the plant's TSs. (Section 1R22.b.2)

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

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

Unit 2 was shut down in Mode 5 (Cold Shutdown) at the beginning of the inspection period for the Cycle 16 refueling outage (U2C16). The licensee performed a reactor startup and synchronized the unit to the grid on May 6, 2006, upon completion of a 43-day refueling outage. Unit 2 operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Plant Systems Preparations for High Temperature and High Wind Conditions

a. Inspection Scope

The inspectors reviewed the licensee's procedures and preparations for high temperature and high wind conditions. The inspectors also reviewed severe weather and plant de-winterization procedures and performed general area walkdowns. During walkdowns of the plant conducted during the last week of May 2006, the inspectors observed housekeeping conditions and 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 the identification and resolution of equipment deficiencies associated with adverse weather mitigation. This activity represented one system inspection sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors completed three partial equipment alignment inspection samples by conducting walkdowns of the following risk significant systems:

- Spent Fuel Pool Cooling System, including makeup capabilities to the Spent Fuel Pool
- Unit 2 North Safety Injection System Train

- Unit 1 CD Emergency Diesel Generator (EDG)

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones. The inspectors reviewed operating procedures, system diagrams, Technical Specification (TS) requirements, and the impact of ongoing work activities on redundant trains of equipment. The inspectors verified that conditions did not exist 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. The spent fuel pool cooling system was selected as a risk significant system that was in service to remove decay heat in the pool immediately following a full core offload during the refueling outage.

In addition, the inspectors verified that equipment alignment problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected condition reports were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours

a. Inspection Scope

The inspectors completed eleven quarterly fire protection inspection samples by performing walkdowns in the following plant areas:

- Unit 1 Turbine Deck 633' Elevation (Fire Zone 129)
- Unit 2 Turbine Deck 633' Elevation (Fire Zone 130)
- Unit 1 Essential Service Water (ESW) Pipe Tunnel 570' 6" Elevation (Fire Zone 112)
- Unit 2 ESW Pipe Tunnel 570' 6" Elevation (Fire Zone 113)
- Unit 1 ESW Pipe Tunnel 587' Elevation (Fire Zone 114)
- Unit 2 ESW Pipe Tunnel 587' Elevation (Fire Zone 115)
- Unit 2 Reactor Head Enclosure (Fire Zone 104)
- Unit 2 Containment Regenerative Heat Exchanger Room 612' Elevation (Fire Zone 119)
- Unit 2 East Containment Accumulator Enclosure 612' Elevation (Fire Zone 121)
- Unit 2 Ice Condenser 640' Elevation (Fire Zone 133)
- Unit 2 Reactor Vessel Pit 612' Elevation (Fire Zone 135)

The inspectors verified that transient combustibles and ignition sources were appropriately controlled; and, assessed the material condition of fire suppression systems, manual fire fighting equipment, smoke detection systems, fire barriers and

emergency lighting units. The inspectors also discussed fire watch duties and practices with licensee personnel.

In addition, the inspectors verified that fire protection related problems were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected condition reports were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

.1 Potential External and Internal Flooding Impact on Safe Shutdown Equipment

a. Inspection Scope

The inspectors reviewed the licensee's resolution of inspector identified issues during previous flood protection inspections in the second quarter of 2005 and the first quarter of 2006, which were documented in Unresolved Item (URI) 05000315/316/2005004-01. This follow-up activity did not count as an inspection sample.

b. Findings

(1) Potential External and Internal Flooding Impact on Safe Shutdown Equipment in the Lake Screen House

Introduction

The inspectors identified a finding of very low safety significance (Green) and a Non-Cite Violation (NCV) of 10 CFR 50, Appendix B, Criteria III. The inspectors identified that the plant's design for flooding events may not mitigate the consequences of external flooding in the Lake Screen House. In the event of a seiche or high waves on Lake Michigan, water could collect in the Lake Screen House and possibly cause damage to safe shutdown plant equipment (i.e., the ESW system and support components).

Discussion

The inspectors reviewed the licensee's flooding analysis and its design features to prevent/mitigate the consequences of internal and external flooding events during the second quarter of 2005 and identified several discrepancies regarding the external flood protection elevation for the plant. The licensee's flooding analysis assumed that the station drainage system would not negatively impact the analysis. In the flooding analysis, the licensee described the roadway on the west side of the plant, along with the shoreline buildup, as a flood protection feature for protection from external flooding.

Two distinct flooding scenarios were postulated to occur, a seiche on Lake Michigan and a worst-case wave run-up. The plant's external flood protection elevation is 594.5' NGVD [National Geodetic Vertical Datum reference system] above mean sea level. The design basis seiche height is 11', which equates to a plant elevation of 594.5' NGVD. In reviewing the inspectors' questions, the licensee discovered that the Lake Screen House was not protected to the 595' elevation as described in Section 10.6 of the Updated Final Safety Analysis Report (UFSAR). The UFSAR included an additional 0.5' of freeboard above the 594.5' external flood protection elevation. Although the ESW pump motors were above the 595' elevation, there were 124 safety-related support components for the ESW pumps that were found during the licensee's review that were located below the 595' elevation.

The inspectors and the licensee reviewed this issue and determined that it was not an immediate operability concern for the ESW system due to the current level of Lake Michigan. The inspectors noted that the lake level has remained at or below 580' NGVD since January 2000, with the design basis maximum lake level being 583.5' NGVD. Therefore, in the event of a design basis seiche of 11', the resultant height of the wave would be less than the height of the road next to the lake (lowest point at 594' NGVD). Also, with the lake level at 580' NGVD, the resultant height of the wave would be just equal to the elevation of the Lake Screen House floor at 591'. The lowest equipment in the ESW pump rooms was about 1' above the floor, providing some margin to submersion. Safety-related components of concern were located about 3' to 4' above the floor, providing even greater margin.

The licensee completed a detailed past operability review of this condition going back to when the plant first began operation and concluded that there would have been no adverse impact on the ESW system in the event of a design basis seiche. Although some of the support components located below the 594.5' elevation would have been wetted, the ESW system would still have remained operable. The licensee's evaluation utilized the maximum Lake Michigan elevation for the plant's operating history, which was recorded in October 1986 at 583.1' NGVD and was 0.4' below the maximum design basis lake level. The licensee also did not consider the 0.5' freeboard component for the purpose of the past operability evaluation, which would have added extra margin to the wave height. The inspectors reviewed the past operability evaluation and concluded that the result was reasonable. The inspectors noted, however, that had the lake level been as high as the design basis lake level of 583.5' NGVD, several more ESW system support components would have been submerged and that could have affected the operability of the ESW system during a design basis seiche event. The licensee was further evaluating corrective actions at the conclusion of this inspection.

<u>Analysis</u>

The inspectors determined that the failure to maintain adequate design control for the affected ESW system components in the Lake Screen House was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the Significance Determination Process (SDP). The inspectors reviewed the examples of minor issues in Inspection Manual Chapter (IMC) 0612,

"Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance because this issue was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences since the failure to maintain adequate design control for the affected ESW system components in the Lake Screen House could possibly have resulted in damage to safe shutdown plant equipment during a design basis seiche event. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." 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 this finding was of very low safety significance (Green) because this finding was a design or qualification deficiency confirmed not to result in loss of operability.

Enforcement

10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the design basis is correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee failed to correctly translate the design basis into specifications for the ESW system by ensuring that ESW system components in the Lake Screen House would be protected to the 595' elevation as described in Section 10.6 of the UFSAR, in the event of flooding due to a design basis seiche event. Because of the very low safety significance, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000315/316/2006004-01). The licensee entered this violation into its corrective action program as CR 05308066.

(2) Inadequate Preventive/Corrective Maintenance on Turbine Building Sump Overflow Check Valve 12-DR-129

Introduction

The inspectors identified a finding of very low safety significance (Green). The licensee failed to perform adequate preventive and corrective maintenance on Turbine Building sump overflow check valve 12-DR-129. As a result, the valve was in a significantly degraded condition such that it would not function to mitigate the consequences of a design basis seiche event. No violation of regulatory requirements was identified.

Discussion

The inspectors reviewed the licensee's flooding analysis and its design features to prevent/mitigate the consequences of internal and external flooding events during the second quarter of 2005 and identified a potential breach in the plant's flood protection

barrier. The Turbine Building sump has an overflow box with a 30" overflow pipe that leads to the lake by way of the Lake Screen House. This line has a 30" flapper type check valve, 12-DR-129, located in the sump overflow box to prevent backflow from the lake. Failure of this non safety-related component, specifically during a design basis seiche event on Lake Michigan, could cause the Turbine Building sump to overflow and back up into the safe shutdown plant equipment rooms. All four of the Unit 1 and Unit 2 EDGs are located on the 587' elevation, with the lowest of the EDG room floor drains at the 584' elevation. The auxiliary feedwater (AFW) pumps for both Unit 1 and Unit 2 are located on the 591' elevation of the Turbine Building. All of these rooms are connected to the Turbine Building sump via floor drains and there are no check valves in the individual equipment room drain lines to prevent back-flow into the floor drain system. The bottom of the overflow pipe is at the 583.5' elevation at its highest point. The highest recorded lake level was 583.5' NGVD; however, the licensee's analysis assumed a worst case seiche of 11' or 594.5' NGVD.

The Turbine Building sump overflow check valve was not previously included in the licensee's check valve preventative maintenance program. It was coded as a "run-to-fail" component. The inspectors inquired into preventative maintenance history for this valve because this was the only barrier from the lake to safe shutdown equipment. Review of the valve's history identified that this valve has been subject to a harsh environment and had previously failed on at least two occasions. In November of 2002, the valve was found broken with a piece of the disc in the overflow box pit. In February 2004, the valve was found further degraded with a broken hinge pin, preventing the valve from operating. The hinge pin was replaced in 2004; however, the licensee was unable to complete repairs to the valve disc due to excessive corrosion. The licensee replaced the check valve in August 2005 in response to concerns the inspectors raised with the valve's condition. The valve had been in a degraded state for almost 3 years before it was replaced.

The inspectors found that the licensee had missed previous opportunities to implement an effective preventive maintenance activity for check valve 12-DR-129. The licensee wrote CR 04321007 in November 2004 to create a preventive maintenance activity for the check valve. The licensee wrote this condition report because the valve had been found in a degraded condition during a sump inspection and no preventive maintenance had been performed on the valve. The inspectors previously identified the lack of an effective preventive maintenance activity for check valve 12-DR-129 in August 2003 and the licensee wrote CR 03234074 to create a preventive maintenance activity for the valve. The inspectors identified the issue then by reviewing a condition report from 1999 (CR 99-29255), which identified that a failure of the non safety-related check valve during a design basis seiche event could cause the Turbine Building sump to overfill and back up through the floor drains to the EDG rooms. The licensee wrote CR 99-29255 to include the valve in its preventive maintenance program, but failed to do so.

As a result of the loss of this flood protection feature for protection from external flooding, high water level in the Turbine Building sump could flow into the AFW pump and the EDG equipment rooms. The inspectors assumed that water could flow into the equipment rooms by way of leakage past non-watertight doors and the plant's

unchecked floor drain system. Any expected water in these rooms could potentially increase to the point of causing multiple trains of safe shutdown equipment to be unavailable to safely shutdown the plant. While there were four high capacity Turbine Building sump pumps (2000 gallons-per-minute (gpm) each), these pumps were not safety-related and a material history review revealed that these pumps were not all functional at the same time.

Analysis

The inspectors determined that the inadequate preventive and corrective maintenance on Turbine Building sump overflow check valve 12-DR-129, which resulted in the valve being found in a significantly degraded condition such that it would not function to mitigate the consequences of a design basis seiche event, was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, Appendix E, and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, the inspectors determined that the finding was of more than minor significance because this issue was associated with the Protection Against External Factors attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations since inadequate preventive and corrective maintenance led to the significantly degraded condition of check valve 12-DR-129.

Phase 1 Assessment

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, and determined that this finding would require a Phase 3 SDP analysis because the finding increased the likelihood of an external flooding event.

Phase 3 Assessment

The Region III Senior Reactor Analyst (SRA) performed a Phase 3 SDP review for this finding. The inspectors determined that the scenario of concern was a seiche, which leads to flooding of the EDG rooms, potentially rendering the EDGs inoperable. The EDGs were considered to be the equipment of greatest concern because the EDG rooms were at a lower elevation than the AFW pump rooms. Because the EDGs are used to mitigate loss of offsite power (LOOP) events, the seiche would have to reach the switchyard to cause the LOOP. The design basis seiche height is 11', which equates to 594.5' NGVD. The east side of the plant is at about the 609' elevation, while the west side (lake side) is at about the 591' elevation. The switchyard is located outside the protected area on a hill, well above the 609' elevation. Therefore, the SRA performed a bounding analysis assuming that the seiche reaches the plant and causes a transient (reactor trip), but not a LOOP.

The SRA used lake surf occurrence fractions from the National Climatic Data Center. Lake surf data was obtained for those counties along Lake Michigan adjacent to Berrien County (where the D. C. Cook Nuclear Plant is located). These were Van Buren County (north) and Lake County (south). According to the National Climatic Data Center, there were a total of 4 lake surf events in 55 years in the three counties. None were classified as seiches. The total (water) area of Berrien and adjacent counties is 1618 square miles. Therefore, the initiating event frequency of a lake surf event striking the site was estimated to be 4.5E-5.

The SRA calculated a conditional core damage probability using the NRC's Standardized Plant Analysis Risk model for D. C. Cook assuming that the seiche results in a transient and common cause failure of all four EDGs to start. The calculated conditional core damage probability was 1.2E-7. As a result, considering the seiche initiating event frequency, the change in core damage frequency for this finding was calculated to be well below 1.0E-6 and this finding was characterized as having very low safety significance (Green).

Cross-cutting Aspects

The inspectors also concluded that this finding affected the cross-cutting area of problem identification and resolution. Specifically, the licensee failed to identify and correct the degraded valve condition. Corrective actions that were taken were not timely, were not commensurate with the significance of the issue, and early corrective actions were ineffective.

Enforcement

No violation of regulatory requirements was identified. This issue is considered to be a finding (FIN 05000315/316/2006004-02) and was entered in the licensee’s corrective action program as CR 00800186.

(3) Inadequate Functionality Evaluation for Degraded Check Valve Condition

Introduction

The inspectors identified a finding of very low safety significance (Green). The licensee did not adequately evaluate the functionality of Turbine Building sump overflow check valve 12-DR-129, while the valve was in a significantly degraded condition such that it would not function to mitigate the consequences of a design basis seiche event. No violation of regulatory requirements was identified.

Discussion

The inspectors reviewed an operability evaluation performed by the licensee for the degraded valve condition as found in August 2005 before it was replaced. In addition to having a piece missing from the disc, the valve was found with a slight gap between the disc and the valve body. Both of these conditions would affect the ability of the check

valve to function. The licensee concluded that plant staff would have about 50 minutes to take action in response to a seiche event before the Turbine Building sump would overfill. The effectiveness of operator actions in response to a design basis seiche was not evaluated by the licensee. The conclusion was based on several assumptions including the operation of one Turbine Building sump pump, the initial sump level being at the sump high level alarm setpoint, and the size of the flow area past the damaged valve disc (assumed to be a rectangular orifice of 65 square inches). The licensee determined based on an hydraulic evaluation that the result would be a net 695 gpm sump fill rate, with one 2000 gpm sump pump running to remove water.

The inspectors were concerned that the condition found and evaluated in August 2005 was not the worst condition found with check valve 12-DR-129. In February 2004, the check valve was found in what was described in the licensee's condition report (CR 04048044) as a "non-functional position," because the valve disc appeared to have fallen off due to a pin failure. Photographs show the valve disc detached, hanging, and rotated away from the open ended pipe. The condition report did not receive a condition evaluation; however, the Operations Department review concluded that the valve was not functional due to the valve disc being detached. The Operations Department review dismissed the potential impact on safe shutdown equipment using "engineering judgement," stating that water backing up into the floor drains on the Turbine Building 591' elevation and flooding the EDG rooms was unlikely to ever happen. This was based on several assumptions, including: (1) a seiche would be of short duration (only several minutes), (2) the Turbine Building sump has a sufficiently large capacity (94,000 gallons) and was normally maintained less than half full, (3) the lake level at the time was at the 569' elevation, and (4) an isolation valve (12-DR-130) was available to isolate the check valve if needed. This conclusion appeared to have been copied from an earlier condition report (CR 03234074) evaluation performed in August 2003.

The inspectors challenged several of the assumptions from the Operations Department review of CR 04048044 and requested that the licensee further evaluate the condition, considering the past functionality of check valve 12-DR-129 for an appropriate time period before the hinge pin was replaced in February 2004. The inspectors questioned the basis for concluding that a seiche would be of short duration since no information supporting this assumption was provided. The inspectors also questioned whether 569' was an appropriate lake level to use, noting that the licensee had used 580.2' NGVD in its August 2005 operability evaluation. The inspectors reviewed recorded Lake Michigan level data provided by the U.S. Army Corps of Engineers on its website and noted that the lake level was never lower than 578' NGVD from November 2002 through August 2005. The inspectors also questioned whether it was appropriate to credit operator action to manually isolate the check valve. The inspectors noted that no credit was taken in the licensee's analyses for operator action to close12-DR-130 in the event of a seiche. Crediting operator action to close this isolation valve would be questionable because: (1) closing 12-DR-130 was not included as an action to take in the licensee's response procedure for a seiche (12-OHP-4022-001-009, "Seiche," Revision 1), (2) operators were not trained to take this action in response to a seiche and would not likely recognize the need to do so until water had already filled the sump and backed-up

into the safe shutdown equipment rooms, and (3) closing 12-DR-130 was not a prescribed contingency action for operators to take in response to a seiche due to the degraded check valve condition.

In response to the inspectors' questions, the licensee wrote CR 06065008 to document the need for a more thorough evaluation of the condition and performed a detailed calculation to determine the potential for flooding in the EDG rooms to support a past operability evaluation for the EDGs. The EDGs were considered to be the equipment of greatest concern because the EDG rooms were at a lower elevation than the AFW pump rooms. The inspectors reviewed calculation MD-12-SD-001-S, "Impact of Seiche on EDGs with Turbine Room Sump Flap Valve Failed," Revision 0. In short, the licensee concluded that no water would have entered the EDG rooms during a design basis seiche event with 12-DR-129 assumed to be totally non-functional. This assumed that at least 3 of the 4 Turbine Building sump pumps were functional and that the maximum lake level was 578.27' NGVD. As a result, the condition that was found in February 2004 would not have had an adverse impact on the operability of the EDGs. The inspectors noted, however, that had the lake level been as high as the design basis lake level of 583.5' NGVD or had only 2 of the 4 sump pumps been functional, water would have entered the EDG rooms and could have possibly affected the operability of the EDGs.

Analysis

The inspectors determined that the failure to adequately evaluate the functionality of Turbine Building sump overflow check valve 12-DR-129 to mitigate the consequences of a design basis seiche event was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, Appendix E and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, the inspectors determined that the finding was of more than minor significance because if left uncorrected, the failure to properly evaluate the operability of equipment important to safety could result in incorrectly concluding that the equipment was operable. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A. The inspectors determined that this finding was related to the Protection Against External Factors attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and would require a Phase 3 analysis because the finding screened as potentially risk significant in the event of flooding. Consistent with the Phase 3 SDP evaluation performed in Section 1R06.b.2, this finding was determined to be of very low safety significance (Green).

Cross-cutting Aspects

The inspectors also concluded that this finding affected the cross-cutting area of problem identification and resolution. Specifically, the licensee failed to adequately evaluate the functionality of check valve 12-DR-129 while the valve was in a significantly

degraded condition. The licensee did not apply appropriate rigor and detail to its evaluation of the non-functional check valve; and as a result, the potential impact on safe shutdown equipment was not evaluated and timely corrective actions were not taken.

Enforcement

No violation of regulatory requirements was identified. This issue is considered to be a finding (FIN 05000315/316/2006004-03). The licensee entered this finding into its corrective action program as CR 06065008.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors completed two annual baseline inspection samples regarding heat sink performance for two heat exchangers directly cooled by the ESW system. The inspectors reviewed maintenance activities for the Unit 2 west component cooling water heat exchanger, 2-HE-15W, and the Unit 2 east containment spray heat exchanger, 2-HE-18E.

The inspectors assessed the as-found and as-left condition of the heat exchangers by direct observation and document reviews to verify that no deficiencies existed, that would adversely impact the heat exchangers' ability to transfer heat to the ESW system as designed. The inspectors observed portions of inspection and cleaning activities, and reviewed documentation to verify that engineering personnel completed the visual inspections in accordance with plant procedure 12-EHP-8913-002, "Heat Exchanger Inspection." The inspectors also verified that the acceptance criteria specified for the visual inspections were satisfactorily met.

The inspectors reviewed condition reports related to heat exchanger problems and verified that identified problems were entered into the corrective action program with the appropriate significance characterization, and that planned and completed corrective actions were appropriate.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping Systems ISI

a. Inspection Scope

From March 27, 2006, through April 20, 2006, the inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor

coolant system (RCS) boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements:

- Dye penetrant examination of the residual heat removal (RHR) heat exchanger, nozzle to shell weld, E-RHRHEX-IN;
- Ultrasonic examination (UT) of safety injection system pipe to elbow weld, 2-SI-57-17; and
- UT of the 1.5T band on the weld overlay repair on pressurizer nozzles A and B.

The inspectors reviewed examinations completed during the previous outage with relevant/recordable conditions/indications that were accepted for continued service to verify that the licensee's acceptance was in accordance with the Section XI of the ASME Code. Specifically, the inspectors reviewed:

- a visual examination, with relevant indications identified on feedwater pipe support 2-GFW-L-825, for which significant corrosion existed due to an aggressive environment;
- a visual examination, with relevant indications identified on chemical and volume control system (CVCS) pipe support 2-ACS-R-913, for which a gap was noted between the nut and the base plate; and
- a visual examination, with relevant indications identified on RCS pipe support 2-GRC-R-574, for which the rod was found bent.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems, which were completed since the beginning of the previous refueling outage, to determine if the welding acceptance and pre-service examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following work activities:

- repair of ISI Class 2 charging pump, 2-PP-50W, discharge piping in the CVCS, welds OW1 through OW2;
- replacement/welding of ISI Class 2 Valve 2-ILA-121-V1 in the emergency core cooling system (ECCS), welds OW1 through OW4; and
- replacement/welding of ISI Class 2 check valve 2-PW-275 in the primary water system, welds OW1 through OW2.

The inspectors performed a review of ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff, and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

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

The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.2 Pressurized Water Reactor Vessel Head Penetration ISI

a. Inspection Scope

As of the end of operating cycle 15, the D. C. Cook Unit 2 vessel head was at 14.40 effective degradation years, which is in the high susceptibility ranking category as described in NRC Order EA-03-009. To meet the inspection requirements of Order EA-03-009, the licensee completed automated UT examinations and eddy current examinations for each of the 79 vessel head penetration nozzles and head vent line penetration nozzles. The licensee also completed 100 percent visual inspection of all the reactor vessel head penetrations and 100 percent bare metal visual inspection.

For each nondestructive examination performed by the licensee, the inspectors verified the following activities were performed in accordance with the NRC Order through direct observation or through record review. No defects were noted during the examination.

- The inspectors conducted a record review of the visual examination (videotape and data sheets) and the licensee's criteria for confirming visual examination quality and to ensure minimum examination coverage.

- The inspectors reviewed a sample of the non-visual examinations performed. The inspectors observed and performed a record review of a minimum of 10 percent of the control rod drive mechanism penetrations. The inspectors reviewed the non-destructive examination procedures and confirmed that the calibration requirements (essential variables) were consistent with those used in vendor mock up demonstrations.

There were no welded repairs completed on the upper head penetrations since the beginning of the previous refueling outage. There were no examinations completed during the previous outage with relevant/recordable indications that were accepted for continued service.

The reviews discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From March 26, 2006, through March 29, 2006, the inspectors reviewed the Unit 2 BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary."

The inspectors conducted a direct observation of BACC visual examination activities to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. Specifically:

- On March 26, 2006, following shutdown, the resident inspectors reviewed a sample of BACC visual examination activities through direct observation. This walkdown was completed with Unit 2 in Mode 4 (Hot Shutdown) and included the lower Containment Building inner volume and annulus. The inspectors verified that the visual inspections emphasized locations where boric acid leaks can cause degradation of safety significant components.

- The inspectors also reviewed the visual examination procedures and examination records for the BACC examination and verified that degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed the following boric acid leak corrective actions to confirm that they were consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI. The inspectors also reviewed the engineering evaluations performed for these same corrective action documents. The evaluations were verified, as applicable, to ensure that ASME Code wall thickness requirements were maintained:

- CR 04328019, component 2-OME-4, "Pressurizer Manway Leak";

C CR 05139017, component 2-PW-282W, "Primary Water to West RHR Pump suction shutoff valve"; and

C CR 05070003, component 2-QCR-300, "RC Letdown Train 'B' Containment Isolation Valve."

The reviews discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube ISI

a. Inspection Scope

The inspectors did not perform a review of this procedure section (reduction in one inspection sample), because the licensee did not perform steam generator inspections this outage due to recent replacement of the steam generators. This was not counted as an inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors completed one quarterly inspection sample of licensed operator requalification training by observing a crew of licensed operators during simulator training on June 27 and 28, 2006. The inspectors assessed the operators' response to the simulated events that included a response to degraded forebay conditions, a decrease in feedwater temperature, and a loss of control room instrumentation distribution loads. The inspectors also observed the post-training critique to assess the licensee evaluators' and the operating crew's ability to identify their own performance deficiencies.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors completed two quarterly maintenance effectiveness inspection samples by evaluating the licensee's handling of selected degraded performance issues involving the following risk-significant structures, systems, and components (SSCs):

- Unit 1 and Unit 2 ESW Pumps
- Unit 1 and Unit 2 Automatic Gas Analyzers

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

- 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 reclassification, and
- appropriateness of performance criteria for SSCs/functions classified (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified (a)(1).

In addition, the inspectors verified that problems associated with the effectiveness of plant maintenance were entered into the licensee's corrective action program with the appropriate characterization and significance. Selected condition reports were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors completed four inspection samples regarding maintenance risk assessments and emergent work evaluations for the following maintenance activities:

- Emergent Maintenance Activity to Repair Unit 1 CVCS Cation Demineralizer Bypass Valve
- Elevated Unit 1 Risk Due to Dual Unit 2 ESW Pump Outage During Refueling Outage
- Emergent Maintenance Activity for Unit 1 Main Turbine Control Valve Spurious Cycling
- Unit 1 Transformer #4 Outage and Transformer 101CD Bolted Disconnect Repair

These activities were selected based on their potential risk significance relative to the reactor safety cornerstones. As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work in the plant's daily schedule, verified that plant risk assessments were completed as required by 10 CFR 50.65(a)(4)

prior to commencing maintenance activities, 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 assumptions. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify that risk analysis assumptions were valid, that redundant safety-related plant equipment necessary to minimize risk was available for use, and that applicable requirements were met.

In addition, the inspectors verified that maintenance risk related problems were entered into the licensee's corrective action program with the appropriate significance characterization. Selected condition reports were reviewed to verify that corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

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

The inspectors completed four baseline inspection samples regarding personnel performance during non-routine plant evolutions as described below.

.1 Inadvertent Loss of RCS Inventory While Placing Emergency Core Cooling Systems in Standby Readiness

a. Inspection Scope

The inspectors reviewed the circumstances contributing to the unexpected lifting of the Unit 2 charging pump suction header safety valve on April 29, 2006, while plant operators were aligning the RHR system for standby readiness. The inspectors reviewed plant procedures, plant computer data, Control Room logs and discussed the evolution with operations personnel. This issue is also discussed in Section 4OA3.1 of this report.

b. Findings

Introduction

A finding of very low safety significance (Green) with an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" was self-revealed. Plant operators, using an inadequate procedure, performed procedural steps to vent the RHR system piping while the system was still connected to the RCS. As a result, the charging pump suction safety valve (2-SV-56) unexpectedly lifted and discharged approximately 120 gallons of water to the pressurizer relief tank.

Description

On April 29, 2006, Unit 2 was in Mode 4 with the RCS at 337 pounds per square inch gauge (psig), 280 degrees Fahrenheit and pressurizer level at approximately 37 percent. The RHR system was in service with the pump's suction aligned to the RCS. Time to boil in the RCS was approximately 3 hours if RHR system cooling was lost.

Plant operators were performing procedure 2-OHP-4021-008-002, "Placing Emergency Core Cooling System in Standby Readiness," as part of a scheduled activity to return the plant to operation near the end of the scheduled refueling outage. Procedure 2-OHP-4021-008-002 was being performed in conjunction with procedure 2-OHP-4021-017-003, "Removing Residual Heat Removal Loop From Service," to isolate the RHR system from the RCS.

The operators opened valve 2-IMO-340 (east RHR heat exchanger to charging pumps suction valve) per step 4.6 of 2-OHP-4021-008-002 to fill and vent the cross-tie piping between the charging pump suction header and the RHR system. However, the RHR system was still aligned to the RCS and the charging system suction piping was pressurized to 337 psig after 2-IMO-340 was opened. Consequently, 2-SV-56 lifted at the design setpoint of 220 psig and water was discharged to the pressurizer relief tank. The operators recognized the problem and closed 2-IMO-340 in about 2.5 minutes to isolate the charging system from the RHR system and safety valve 2-SV-56 then closed to stop the discharge of water.

Approximately 120 gallons of RCS inventory was discharged to the pressurizer relief tank. However, the RHR system was not adversely impacted and remained in service during this evolution. The licensee determined that the safety valve being open for 2.5 minutes resulted in a flow rate of approximately 48 gpm, which was greater than the 25 gpm identified RCS leak rate limit for declaring an Unusual Event. As discussed in Section 4OA3.1 of this report, the licensee initially classified this as an Unusual Event and later retracted the event notification. This issue was entered into the licensee's corrective action program as CR 06119027.

Licensee personnel evaluated this issue and concluded that the apparent cause was procedure 2-OHP-4021-008-002 did not provide sufficient direction to ensure that the RCS was isolated from the RHR system prior to performing steps that manipulated valves in systems that connect with the RHR system. The inspectors reviewed the procedure and the evaluation and concluded that the identified apparent cause was reasonable. Corrective actions included revising procedure OHP-4021-008-002 for both Unit 2 and Unit 1, and completing an engineering evaluation to ensure that the charging pump suction header piping did not experience a detrimental over-pressure condition.

Analysis

The inspectors determined that performing procedural steps to vent RHR system piping while the system was still connected to the RCS was a performance deficiency that warranted a significance evaluation. The inspectors assessed this finding using the

SDP. The inspectors determined that the finding was of more than minor significance in accordance with IMC 0612, Appendix B. The finding was associated with the Procedure Quality attribute of the Initiating Events cornerstone, and adversely impacted the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown operations. Specifically, the finding resulted in an unintended loss of RCS inventory while shutdown in Mode 4.

Using IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," Checklist 4, "Pressurized Water Reactor Refueling Operation: RCS level > 23 feet OR Pressurized Water Reactor Shutdown Operation with Time to Boil > 2 hours and Inventory in the Pressurizer," and Table 1, "Losses of Control," the inspectors determined that the finding did not require a quantitative assessment because adequate mitigation capability was maintained in that all of the items on Checklist 4 were being met. Also, the finding did not represent a loss of control because the 120 gallons of RCS water discharged to the pressurized relief tank was less than 2 feet of inventory lost from the pressurizer, and there was no loss of thermal margin. Therefore, the finding was determined to be of very low safety significance (Green).

Cross Cutting Aspects

This finding was related to the cross-cutting area of human performance because the procedure utilized to complete the task was not complete. Specifically, the procedure did not contain adequate direction to ensure that the RCS was isolated from the RHR system prior to performing steps that manipulated valves in the charging system that cross-connect with the RHR system.

Enforcement

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," required, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Contrary to the above, procedure 2-OHP-4021-008-002, "Placing Emergency Core Cooling System in Standby Readiness," Revision 16, was not appropriate to the circumstances, in that it did not provide adequate direction to ensure that the RCS was isolated from the RHR system prior to performing steps that manipulated valves in systems that cross-connect with the RHR system. Consequently, on April 29, 2006, with Unit 2 in Mode 4, operators opened valve 2-IMO-340 (east RHR heat exchanger to charging pumps suction valve) per Step 4.6 of 2-OHP-4021-008-002 while the RHR system was still aligned to the RCS. As a result, charging system suction piping was pressurized to RCS pressure of 337 psig and the suction piping safety valve (2-SV-56) lifted at the design setpoint of 220 psig, discharging 120 gallons of water to the pressurizer relief tank. Because the finding was determined to be of very low safety significance and this issue was entered into the licensee's corrective action program (CR 06119027), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000316/2006004-04).

.2 Heavy Load Dropped While Removing Vertical Bulkhead Blocks in Unit 2 Containment

a. Inspection Scope

The inspectors reviewed the events and circumstances surrounding the lift rig that failed on March 27, 2006, while removing a 37 ton vertical bulkhead block with the plant in Mode 5 (Cold Shutdown). The inspectors reviewed plant procedures and discussed the evolution with licensee personnel to verify that the appropriate plant procedures were adhered to.

b. Findings

Introduction

A finding of very low safety significance (Green) was self-revealed. The licensee failed to have adequate measures in place to detect and correct binding while lifting a heavy load with the Unit 2 containment polar crane. As a result, the lift rig device failed due to binding and a 37 ton load dropped inside the Unit 2 containment. No violation of regulatory requirements was associated with this finding.

Description

On March 27, 2006, with the plant in Mode 5, refueling outage preparation activities were in progress that included removing three vertical bulkhead blocks that formed a barrier between the reactor vessel and refueling cavity during plant operations. Each vertical bulkhead block was approximately 20 feet wide, 11 feet high, 21 inches deep and weighed approximately 37 tons. The ends of the vertical bulkhead blocks were positioned in retaining channels that span from the bottom to the top of the reactor cavity to provide support for holding the blocks in place. The vertical bulkheads, along with four horizontal missile shields that rest on top of them and over the reactor vessel, function to route steam to lower containment and up through the ice condenser baskets in the event of a design basis accident.

The vertical bulkhead blocks and horizontal missile shields had to be removed to conduct refueling activities. The 250 ton Containment Building polar crane was used to remove the blocks. The sequence was to remove one horizontal missile shield to provide access to and then remove the three vertical bulkhead blocks. Three horizontal missile shields remain in place over the reactor vessel while the vertical bulkhead blocks were removed. While removing the third vertical bulkhead block, the lift rig device failed when the block was approximately 15 feet off the reactor cavity floor. Consequently, the vertical bulkhead block fell back to the reactor cavity floor while remaining in the retaining channels, which allowed the block to fall to its original position. Licensee management issued a stop work order for all heavy lifts as an interim measure. Also, Rapid Event Response and Failure Investigation Process teams were immediately assembled to review this issue and determine the extent of damage to plant equipment and the refueling cavity.

Licensee personnel toured the Unit 2 Containment Building and inspected the refueling cavity liner and the reactor cavity area to identify any resultant damage to plant SSCs. The inspections and walkdowns did not identify any adverse affects on structural components in lower containment or the reactor cavity. No rips or tears were found in the reactor cavity stainless steel liner. Vendor assisted inspections of the polar crane identified that the cable had jumped one of its sheaves and, based on vendor recommendations, the entire cable was replaced. The vertical bulkhead block had no structural damage but did exhibit concrete spalling and depressions on each lower corner, which were repaired prior to plant restart. Also, prior to returning the plant to Mode 4, licensee personnel verified that the vertical bulkhead's design function to form a barrier between the reactor vessel and reactor cavity was maintained.

This issue was entered into the licensee's corrective action program as Category 1 CR 06086010, which required a root cause evaluation. Licensee personnel concluded the root cause for this issue was that the lift method for removing the vertical bulkhead did not allow for adequate detection and correction of load binding to prevent overloading the lift rig assembly. Corrective actions included revising procedures 12 OHP-4050-FHP-014, "Removal and Storage of the Reactor Missile Shields, Cavity Covers and Seismic Restraints," and 12-OHP-4050-FHP-041, "Reactor Missile Shield Cavity Cover and Seismic Restraint Installation," to require using a load cell while removing and installing the vertical bulkhead blocks.

Analysis

The inspectors determined that failing to have adequate measures in place to detect and correct binding while lifting a heavy load was a licensee performance deficiency that warranted a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors determined that the finding was of more than minor significance in accordance with IMC 0612, Appendix B. Specifically, if left uncorrected, this issue could lead to a more significant safety concern in that a dropped heavy load could impact and adversely affect plant safety-related SSCs. This finding is not suitable for an SDP evaluation but has been reviewed by NRC management and was determined to be of very low safety significance (Green). This finding was not greater than Green because no adverse consequences to plant safety-related or risk significant SSCs resulted from the dropped load.

Cross Cutting Aspects

This finding was related to the cross-cutting area of human performance because the procedure utilized to complete the task was not complete. Specifically, the procedure did not require a load cell while lifting the vertical bulkhead blocks and therefore did not provide adequate detection of load binding, which could be corrected to prevent overloading the lift rig assembly.

Enforcement

No violation of regulatory requirements was identified. This issue is considered to be a finding (FIN 0500316/2006004-05). The licensee entered this issue into its corrective action program as Category 1 CR 06086010, which required a root cause evaluation.

.3 Operator Response to Inadvertent Safety Injection on Unit 2 While In Mode 5

a. Inspection Scope

The inspectors reviewed the Control Room operators' response to an inadvertent safety injection signal that was received on April 27, 2006, with Unit 2 in Mode 5. The inspectors reviewed plant procedures and Control Room logs, and discussed the issue with Operations personnel to verify that the operators' response was in accordance with plant procedures. The events and circumstances that caused the inadvertent safety injection signal will be assessed during a forthcoming review of Licensee Event Report (LER) 05000316/2006-003-00, "Inadvertent Emergency Core Cooling System Actuation During Testing," that was generated for this issue.

b. Findings

No findings of significance were identified.

.4 Inadvertent Closure of Component Cooling Water Outlet Valve From Letdown Heat Exchanger

a. Inspection Scope

On April 25, 2006, while performing testing in the Unit 2 Control Room in accordance with 2-OHP-4030-232-217A, "DG2CD Load Sequencing & Engineered Safety Features Testing," the component cooling water outlet valve from the letdown heat exchanger (2-CRV-470) unexpectedly closed. This resulted in an increase in letdown temperature and isolation of the RCS filter. A minor level increase was noted in the pressurizer due to the letdown isolation. The inspectors responded to the Control Room to observe operator recovery actions, and reviewed Control Room logs and plant procedures to verify that the operators' response was in accordance with procedural requirements.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors completed five baseline inspection samples associated with operability evaluations by reviewing the following condition reports:

- CR 06093032, "Significant Increase in Vibrations Detected on 1-PP-7W," Regarding Unit 1 West ESW Pump"
- CR 04048044, "During Inspection of 12-DR-129, the Valve Was Found Out of Position. The Disc Appeared to Have Fallen Off Due to Pin Separation/Failure"
- CR 06097046," Modes 1-4 Aggregate Operability Determination Evaluation for Unit 2"
- CR 06100045, "Valve 2-SI-189 Was Unable to Be Pressurized While Attempting As-found Local Leak Rate Testing During U2C16 Refueling Outage"
- CR 06073017, "Unit 2 Lower Outer Airlock Door Was Found Not Fully Closed"

The inspectors verified that the conditions did not render the associated equipment inoperable or result in an unrecognized increase in plant risk. When applicable, the inspectors verified that the licensee appropriately applied TS limitations and appropriately returned the affected equipment to an operable status.

In addition, the inspectors verified that problems related to the operability of safety-related plant equipment were entered into the licensee's corrective action program with the appropriate characterization and significance.

b. Findings

A finding associated with the inspectors' review of CR 04048044 is documented in Section 1R06.b.3 of this report. Findings related to CR 06100045 and CR 06073017 are documented in Sections 1R22.b.1 and 4OA3.3, respectively. No other findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors completed eight baseline inspection samples pertaining to post maintenance testing by assessing testing activities that were conducted on the following plant equipment:

- Unit 2 AB EDG Governor Digital Reference Unit Replacement
- Unit 2 AB EDG Voltage Regulator Replacement
- Unit 2 AB EDG Starting Air Jet Assist Control Valve 2-XRV-220 Replacement
- Unit 2 East Centrifugal Charging Pump Replacement
- Unit 2 East ESW Pump Replacement
- Unit 2 West Centrifugal Charging Pump Seal Replacements
- Unit 2 CD EDG Starting Air to Turbocharger Pressure Reducing Valve 2-XRV-228 Repair
- Unit 2 CD EDG 2R Cylinder Jacket Water Leak Repair

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 the 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.

b. Findings

A finding related to the Unit 2 east centrifugal pump replacement is discussed in NRC IR 05000315/316-2006009. No other findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Unit 2 Refueling Outage (U2C16)

a. Inspection Scope

The inspectors evaluated the licensee's conduct of Unit 2 refueling outage activities to assess the licensee's control of plant configuration and management of shutdown risk. This represented one inspection sample. 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:

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

The inspectors observed portions of the plant cooldown, including the transition to shutdown cooling to verify that the licensee controlled the plant cooldown in accordance with the TS. The inspectors observed operators drain the RCS to mid-loop conditions to accommodate vacuum fill of the RCS near the end of the refueling outage to verify that means of adding inventory to the RCS were available, sufficient indications of RCS water level were operable, and perturbations to the RCS were avoided. The inspectors also observed portions of the restart activities to verify that TS requirements and administrative procedure requirements were met prior to changing operational modes or plant configurations. Major restart inspection activities performed included:

- verification that RCS boundary leakage requirements were met prior to entry into Mode 4 and subsequent operational mode changes;

- verification that containment integrity was established prior to entry into Mode 4;
- inspection of the Containment Building, including the ice condenser, to assess material condition and search for loose debris, which if present could be transported to the containment recirculation sumps and cause restriction of flow to the ECCS pump suctions during loss-of-coolant accident conditions;
- verification that the material condition of the Containment Building and ECCS recirculation sumps met the requirements of the 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 reviewed the issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for refueling outage issues documented in selected condition reports.

b. Findings

Findings related to two non-routine evolutions conducted during the Unit 2 refueling outage are discussed in Section 1R14 of this report. No other findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors completed eleven inspection samples regarding surveillance testing by reviewing the following activities. This constituted two local leak rate test (LLRT) samples, three Inservice Testing (IST) samples, and six routine samples.

- 2-EHP-4030-234-203, "Unit 2 LLRT" (two LLRT samples)
- 12-EHOP-4030-002-316, "Subcritical Physics Tests with Subcritical Rod Worth Measurement" (routine sample)
- 2-OHP-4030-232-217A, "DG2CD Load Sequencing and ESF [Engineered Safety Features] Testing" (routine sample)
- 2-OHP-4030-232-217B, "DG2AB Load Sequencing and ESF [Engineered Safety Features] Testing" (routine sample)
- 2-OHP-4030-208-008R, "ECCS Check Valve Test," Attachment 1, "Residual Heat Removal Suction and Discharge Check Valve Test" (IST sample)
- 2-OHP-4030-208-008R, "ECCS Check Valve Test," Attachment 8, "Accumulator Check Valve Test" (IST sample)

- 2-EHP-4030-203-208, "ECCS Flow Balance - Boron Injection System" (routine sample)
- 2-EHP-4030-234-202, "Integrated Leak Rate Test" (routine sample)
- 2-OHP-4030-210-022V, "ESW Flow Verification" (routine sample)
- 2-OHP-4030-256-017T, "Turbine Driven Auxiliary Feedwater System Test" (IST sample)

b. Findings

(1) Failure to Perform As-found Local Leak Rate Testing for a Containment Isolation Valve

Introduction

The inspectors identified a finding of very low safety significance (Green) and an NCV of TS Surveillance Requirement (SR) 3.6.1.1. The licensee failed to perform an as-found LLRT for containment isolation valve 2-SI-189 (ECCS safety valves discharge to the primary relief tank containment isolation check valve) prior to performing maintenance that affected the valve's leak tightness as required by the plant's TSs.

Discussion

On April 10, 2006, operators were unable to pressurize containment isolation check valve 2-SI-189 while performing LLRT during the Unit 2 refueling outage. This was supposed to have been an as-found LLRT for the valve, however, the valve had been disassembled earlier in the day for a visual inspection and then reassembled. A subsequent investigation by the licensee identified that the valve seat contact was unacceptable by feeler gage measurement and that the bonnet pins were protruding slightly. These conditions were corrected and an as-left LLRT was satisfactorily completed for 2-SI-189 on April 11th.

The licensee completed an evaluation of the initial valve test failure and concluded that the visual inspection performed prior to the LLRT was the most likely time that the valve became inoperable. This conclusion was reached because no maintenance had been performed on 2-SI-189 until it was disassembled on April 10th and the valve had been successfully tested for leakage during the previous refueling outage. There was no evidence to indicate that the condition existed before the visual inspection. The inspectors reviewed the licensee's condition evaluation and determined that it reached a reasonable conclusion. The licensee attributed the failure to perform an as-found LLRT for the valve to a scheduling sequence error and concluded that containment integrity was not affected by the initial valve test failure. The licensee evaluated the scheduling sequence error in CR 06101012 and implemented corrective actions to revise the planning and scheduling activities for testing this valve.

The inspectors were concerned that the true as-found condition of 2-SI-189 was unknown and could not be evaluated. The purpose of performing as-found testing was to prove that the integrity of the containment penetration was sufficient to prevent a release of radioactivity following an accident in excess of established limits during the

previous operating cycle. Although the licensee promptly recognized the failure to complete an as-found LLRT for 2-SI-189, the inspectors identified that the licensee did not recognize and evaluate this as a failure to comply with TS SR 3.6.1.1.

Analysis

The inspectors determined that the failure to perform an as-found LLRT for containment isolation valve 2-SI-189 was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, Appendix E and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, Appendix B, the inspectors determined that this finding was of more than minor significance because it was associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that the physical design barriers (e.g., containment) protect the public from radio-nuclide releases caused by accidents or events since the true as-found condition of valve 2-SI-189 was unknown and could not be evaluated. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," and determined that this was a Type "B" finding. Type "B" findings have no impact on the determination of Core Damage Frequency and therefore they are not processed through the Core Damage Frequency based SDP. These findings, however, are potentially important to Large Early Release Frequency determinations. The inspectors determined during initial screening of the finding using Section 6.2, "Approach for Assessing Type 'B' Findings," that the issue was of very low safety significance (Green) because Unit 2 was defueled at the time and containment integrity was not required.

Cross-cutting Aspects

The inspectors also concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee failed to properly sequence the valve's visual inspection activity after the as-found LLRT into its scheduling process.

Enforcement

Technical Specification SR 3.6.1.1 required, in part, that the licensee perform required visual examinations and leakage rate testing in accordance with the Containment Leakage Rate Testing Program. Technical Specification 5.5.14 required, in part, the licensee to establish a program for leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995. In Regulatory Guide 1.163, the NRC approved Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-based Option of 10 CFR Part 50, Appendix J," as an acceptable method for complying with the provisions of Option B in 10 CFR Part 50, Appendix J. The licensee implemented

its Containment Leakage Rate Testing Program using Engineering Head Instruction (EHI) 5300, "D. C. Cook Nuclear Plant Containment Leakage Rate Testing Program (Appendix J)," Revision 3. EHI 5300, Step 4.4.5.a required, in part, that as-found LLRTs of containment components shall be performed prior to maintenance, repairs, or inspections that could reduce containment leakage integrity. This is consistent with NEI 94-01, Section 10.2.1.3, "Repairs of Adjustments," which stated, in part, that an as-found Type B test shall be performed prior to any maintenance, repair, modification, or adjustment activity if the activity could affect the penetration's leak tightness. Contrary to the above, on April 10, 2006, the licensee disassembled containment isolation valve 2-SI-189 for an internal visual inspection without having performed an as-found LLRT. Because of the very low safety significance, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000316/2006004-06). The licensee entered this violation into its corrective action program as CR 06151087.

(2) Failure to Submit a Required Licensee Event Report

Introduction

The inspectors identified a Severity Level IV NCV of 10 CFR 50.73(a)(1). The licensee failed to submit a required LER within 60 days after discovery of an event requiring a report. The event involved the licensee's failure to meet Containment Leakage Rate Testing Program requirements in accordance with TS SR 3.6.1.1, a condition prohibited by the plant's TS.

Discussion

As discussed in Section 1R22.b.1 above, the inspectors identified that the licensee failed to perform an as-found LLRT for containment isolation valve 2-SI-189 prior to performing maintenance that affected the valve's leak tightness as required by the plant's TS. In response to the inspectors identifying this issue, the licensee wrote condition report CR 06151087 to evaluate the TS non-compliance and to review it with respect to the regulatory reporting requirements. The licensee incorrectly concluded that the failure to perform an as-found LLRT for containment isolation valve 2-SI-189 was not a condition prohibited by TS SR 3.6.1.1, and therefore failed to submit the required LER.

The inspectors discussed with the licensee the basis for the conclusion that as-found testing was not required. The licensee based its conclusion on its interpretation of excerpts from two documents that had not been reviewed and endorsed by the NRC staff and were not part of the current licensing basis for the plant. The first document was a collection of questions and answers drafted by the NEI following an Appendix J, Option B workshop it held in December 1995. The second document was ANSI/ANS-56.8-2002, "Containment System Leakage Testing Requirements."

Analysis

The inspectors determined that the failure to report this issue as a condition prohibited by the plant's TS in accordance with 10 CFR 50.73(a)(2)(i)(B) was a licensee performance deficiency warranting a significance evaluation. The inspectors determined that this finding was of more than minor significance because the NRC relies on licensees to identify and report conditions or events meeting the criteria specified in the TS and the regulations in order to perform its regulatory function. The inspectors identified to the licensee prior to the 60-day reporting deadline that this issue was a condition prohibited by the plant's TS and that it was therefore reportable. Because this issue affected the NRC's ability to perform its regulatory function, it was evaluated with the traditional enforcement process. Consistent with the guidance in Section 7.10 and Supplement I, paragraph D.4, of the NRC Enforcement Policy, this finding was determined to be a Severity Level IV NCV.

Cross-cutting Aspects

The inspectors also concluded that this finding affected the cross-cutting area of problem identification and resolution. Specifically, the licensee incorrectly evaluated the condition and concluded that the failure to perform an as-found LLRT for containment isolation valve 2-SI-189 was not a condition prohibited by TS SR 3.6.1.1, based on its interpretation of documents that were not part of the licensing basis for the plant.

Enforcement

10 CFR 50.73(a)(1) required, in part, that the licensee submit an LER for any event of the type described in this paragraph within 60 days after the discovery of the event. 10 CFR 50.73(a)(2)(i)(B) required, in part, that the licensee report any operation or condition prohibited by the plant's TS. Contrary to the above, the licensee failed to submit a required LER within 60 days after discovery of an event on April 10, 2006. The event involved the licensee's failure to meet Containment Leakage Rate Testing Program requirements in accordance with TS SR 3.6.1.1, a condition prohibited by the plant's TS. This is a Severity Level IV violation consistent with Section 7.10 and Supplement I, paragraph D.4, of the NRC Enforcement Policy and is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000316/2006004-07). The licensee entered this violation into its corrective action program as CR 06151087.

(3) Failure to Establish Appropriate TS Surveillance Acceptance Criteria for the EDGs

Introduction

The inspectors identified a finding of very low safety significance (Green) when the licensee failed to establish appropriate TS surveillance acceptance criteria for full load rejection testing of the EDGs with its implementation of Improved Standard Technical Specifications (ITS). This was a self-revealed NCV of 10 CFR 50, Appendix B, Criteria III, "Design Control."

Discussion

While testing the Unit 2 AB EDG on March 26, 2006, the licensee was unable to meet the TS SR 3.8.1.11 maximum voltage limit of 5000 volts during and following a load rejection. This was a new and more restrictive limit incorporated into the TS with the licensee's implementation of ITS in September 2005. The conversion to ITS included more restrictive criteria for the full load rejection test, including the 5000 volts maximum voltage limit and a 0.86 maximum power factor limit when the EDG is synchronized with offsite power. The basis for the 5000 volts limit was EDG damage protection. The 0.86 power factor was representative of the actual inductive loading an EDG would see under design basis accident conditions. Since the more restrictive criteria was not in the licensee's previous TS, testing had not been performed under the conditions (power factor *and* voltage) prescribed in the ITS. It should be noted that the licensee established what those conditions should be for ITS, but failed to establish an appropriate basis for the values chosen.

The licensee replaced the voltage regulator, contacted a diesel generator expert and ran the test two more times. The testing was performed with the EDG synchronized to offsite power and the grid voltage was thought to be higher than normal, but within acceptable limits. The testing results were close to the 5000 volts limit, but was just over it when the licensee applied the 55 volts measurement uncertainty correction to the voltage. The licensee made several adjustment attempts, but was not able to improve on the result. The engine passed all other testing conducted and was running acceptably.

The licensee finally concluded that a change to the TS acceptance criteria was needed and submitted an emergency TS amendment request to restore the EDG to an operable status. The NRC staff reviewed and approved the request as Amendment 276 to Facility Operating License Number DPR-74 for Unit 2 in a letter dated April 13, 2006. The change revised the maximum voltage limit to 5350 volts.

The inspectors concluded that the licensee did not properly validate the ITS values for TS SR 3.8.1.11 prior to ITS implementation. No formal calculation or evaluation was performed by the licensee to support the basis for the 5000 volts and 0.86 power factor. The licensee's apparent cause evaluation of this issue determined that the validation of the ITS values simply consisted of reviewing the previous full load rejection test results and seeing that the peak voltage did not approach the 5000 volt maximum value that was bracketed in the NUREG 1431 Standard Westinghouse ITS. The addition of the voltage restriction and the power factor requirement was not clearly identified as a change requiring verification/validation. The licensee summarized this as a "flawed technical review" in its apparent cause evaluation. Based on this hindsight, the inspectors concluded that the need for the emergency TS amendment was preventable had the licensee done a more rigorous validation of the TS SR values prior to ITS implementation.

The inspectors were concerned that the lack of rigor in determining appropriate TS SR acceptance criteria that was revealed during this testing may exist for other TS SR

acceptance criteria that were changed or introduced during ITS implementation. The 5000 volts limit in this case was overly restrictive, such that it could not be met while testing the EDG with a power factor that was less than or equal to 0.86. The EDG was otherwise fully capable of fulfilling its design function and was operable. The same may not be true for other TS SR acceptance criteria that were changed or introduced during ITS implementation if the new criteria were less restrictive. In that case, unacceptable SSC performance could be masked by otherwise acceptable surveillance test results. To date, no other unacceptable TS surveillance acceptance criteria have been identified.

Analysis

The inspectors determined that the failure to properly validate TS surveillance acceptance criteria prior to ITS implementation was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the SDP. The inspectors reviewed the examples of minor issues in IMC 0612, Appendix E and determined that there were two examples related to this issue. Examples 3j and 3k describe design control issues that would be considered to be of more than minor significance based on programmatic concerns identified with the issue that could lead to worse errors if not corrected. This finding was not suitable for an SDP evaluation, but has been reviewed by NRC management and was determined to be a finding of very low safety significance (Green). The finding was determined not to be greater than Green because there was no actual adverse impact to plant equipment.

Cross-cutting Aspects

The inspectors also concluded that this finding affected the cross-cutting area of human performance. Specifically, the licensee failed to adequately validate the ITS values for TS SR 3.8.1.11 prior to ITS implementation. The licensee did not apply appropriate rigor and detail to its evaluation of the new TS SR acceptance criteria; and as a result, the engine could not meet the criteria when tested.

Enforcement

10 CFR 50, Appendix B, Criterion III, "Design Control," required, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in Section 50.2 and as specified in the license application are correctly translated into specifications, drawings, procedures, and instructions. 10 CFR 50.36©) required, in part, that the TS will include surveillance requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met. Contrary to the above, the licensee failed to correctly translate the design basis into TS SR 3.8.1.1 with the change implemented by Amendment 269 on June 1, 2005. Specifically, the licensee failed to establish a valid basis for the acceptance criteria that included a 5000 volts maximum voltage limit and a 0.86 maximum power factor limit when the EDG is synchronized with off-site power. Because of the very low safety significance, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy

(NCV 05000316/2006004-08). The licensee entered this violation into its corrective action program as CR 06085045.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors completed one inspection sample by reviewing the following temporary modification that was utilized on plant equipment:

- 2-TM-06-13-RO, "Tap Changes for the Unit 2 Auxiliary Transformers 2-TR2AB and 2-TR2CD During the 2006 Unit 2 Refueling Outage (U2C16)"

The inspectors interviewed engineering, operations and maintenance department personnel, and reviewed the design documents and applicable 10 CFR 50.59 evaluation to verify that TS and the UFSAR requirements were satisfied. The inspectors reviewed documentation and conducted plant walkdowns to verify that the modification was implemented as designed and that the modification did not adversely impact system operability or availability.

The inspectors also reviewed a sample of condition reports pertaining to temporary modifications to verify that problems were entered into the corrective action program with the appropriate significance characterization and that corrective actions were appropriate.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

The inspectors reviewed and discussed with licensee Emergency Preparedness (EP) staff records on the operation, maintenance, and testing of the ANS in the D. C. Cook plant's Emergency Planning Zone to determine whether the ANS equipment was adequately maintained and tested during 2004, 2005, and 2006 in accordance with emergency plan commitments and procedures. The inspectors also reviewed a sample of preventative and non-scheduled maintenance records to determine whether ANS equipment malfunctions were given timely attention and whether the corrective action program was adequately used to track these malfunctions. The inspectors reviewed records of scheduled ANS tests conducted from November 2004 through April 2006.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed procedures containing details on the primary and alternate methods of initiating an ERO activation to augment the on-shift ERO. The inspectors also discussed the processes and reviewed the procedures for maintaining the plant's ERO roster and the ERO telephone directory. The inspectors reviewed records of unannounced, off-hours augmentation tests, which were conducted August 2004 through November 2005 and involved ERO members assigned to the emergency response facilities, to assess the adequacy of the tests and resulting corrective actions.

The inspectors also reviewed records of an additional unannounced, off-hours augmentation drill conducted on August 24, 2004, which involved ERO members actually reporting to their assigned response facilities, to verify the Emergency Plan's minimum staffing commitments.

The inspectors also reviewed the ERO Phone Directory to verify that adequate numbers of personnel were assigned to each key and support position. The inspectors reviewed training records of a random sample of 26 ERO members, who were assigned to key and support positions, to verify that they were currently trained for their assigned positions.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed portions of Quality Assurance staff's 2005 and 2006 audits that addressed aspects of the licensee's EP program to verify that these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also assessed the adequacy of the Quality Assurance staff's assessments of the adequacy of the licensee's interfaces with State and County emergency management agencies and local support organizations. The inspectors also reviewed records of a sample of EP drills conducted during 2004 and 2005, as well as the May 2005 biennial exercise, to verify that the licensee adequately critiqued these drills and the exercise and to determine if corrective actions on identified concerns were either adequately completed or in

progress. Samples of corrective action program records and completed corrective actions were reviewed to determine whether EP program concerns and issues were adequately addressed.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed the licensee's access controls and survey data for the following work areas located within radiation, high radiation, and locked high radiation areas in the plant to determine if radiological controls, postings, and barricades were acceptable:

- Unit 1 and 2 Auxiliary Building (selected areas);
- Unit 2 Upper and Lower Containment; and
- Unit 2 Reactor Vessel Head Temporary Storage/Staging Area.

The inspectors reviewed the radiation work permits (RWPs) that governed access to these areas, and that defined the radiological conditions to ensure the work control instructions, and control barriers that had been specified were adequate. The inspectors walked down selected areas in the Unit 2 Containment Building, and in the Unit 1 and 2 Auxiliary Building, to verify that licensee surveys, and postings were complete and accurate, and to assess the adequacy of physical barriers for high and locked high radiation areas.

These reviews represented one required inspection sample.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective outage exposure history, Unit 2 outage exposure trends, and ongoing outage activities in order to assess current performance, and exposure challenges. This included determining the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment.

The inspectors reviewed the Unit 2 refueling outage (U2C16) work, and the associated work activity exposure, and time/labor estimates for the following work activities which were likely to result in the highest personnel collective exposures or were otherwise radiologically significant work activities:

- Under Reactor Vessel Inspections;
- Refuel Cavity Decontamination Activities;
- Insulation Activities in the Containment Building;
- Scaffold Erection/Removal in the Containment Building;
- Reactor Coolant Pump Seal Activities; and
- In-Service Tests and Inspections in Containment.

The inspectors also reviewed radiological data from the last Unit 1 (U1C20) Refuel Outage (April 2005), and reviewed site specific trends in collective exposures, based on plant historical exposure, and source term data. The inspectors reviewed procedures associated with maintaining occupational exposures ALARA, and assessed those processes used to estimate and track work activity exposures.

These reviews represented four required inspection samples.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors obtained the licensee's list of Unit 2 outage work activities ranked by estimated exposure that were in progress during the outage and reviewed the following ten radiologically significant work activities:

- U2C16 Remove and Replace Reactor Head, Upper Internals, and Reactor Head O-Rings (RWP 062102);
- U2C16 Refuel Restoration Work (RWP 062105);

- U2C16 Control Rod Drive Mechanism Head Inspections (RWP 062106);
- U2C16 Untrained Workers and Their Escorts (RWP 062108);
- U2C16 Containment Install, Modify and Remove Scaffold (RWP 062142);
- U2C16 Perform In-Service Inspection Activities in Containment (RWP 06 2143);
- U2C16 U2 Containment Valve Maintenance and Repair Work (RWP 062145);
- U2C16 Reactor Coolant Drain Tank Locked High Radiation Area Activities (RWP 062176);
- U2C16 Under Reactor Vessel Inspections (RWP 062187); and
- U2C16 Pressurizer Weld Overlay (RWP062190).

For the activities listed above, as well as dose significant work completed during the last Unit 1 refuel outage (U1C20), the inspectors reviewed the ALARA Plans and associated total effective dose equivalent ALARA evaluations, exposure estimates, exposure mitigation information, and post outage (U1C20) reports, in order to verify that the licensee had developed radiological engineering controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The inspectors compared the exposure results achieved through the first 21 days of the Unit 2 Refueling Outage, including the dose rate reductions, and person-rem expended with the dose projected in the licensee's ALARA planning for these 10 work activities. Reasons for inconsistencies between intended (projected) and actual work activity doses were evaluated to determine if the activities were planned reasonably well and to ensure the licensee identified any work interface/planning deficiencies.

The interfaces between operations, radiation protection, maintenance, and scheduling groups were reviewed to varying degrees to identify potential interface problems that significantly affected outage dose. The extension of ALARA requirements into work procedures and/or RWP documents was also evaluated to verify that the licensee's radiological job planning was integrated into the work process.

The inspectors evaluated if work activity planning included consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components/piping and system flushing, and sequencing of scaffold, and shielding installation/removal along with logic-ties in the work scheduling process in order to maximize dose reduction. The licensee's work in progress reports were reviewed for selected outage jobs that accrued collective exposures of 50 and 80 percent of that projected to verify that the licensee could identify problems and address them as work progressed. Post outage reports for U1C20 and current Unit 2 outage RWP jobs that accrued greater than one rem and exceed 125 percent of the projected dose, were also reviewed to ensure that work was adequately evaluated and suspended if warranted, and that identified problems were entered into the licensee's corrective action program consistent with the licensee's procedure.

These reviews represented three required and five optional inspection samples.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's assumptions and basis for its collective outage exposure estimate, and evaluated the methodology and practices for projecting work activity specific exposures. This included evaluating both dose rate and time/labor estimates for adequacy, compared to historical station specific or industry data.

The inspectors reviewed the licensee's process for adjusting outage exposure estimates, when unexpected changes in scope, emergent work, or other unanticipated problems were encountered, which significantly impacted worker exposures. This included, determining that adjustments to estimated exposure (intended dose) were based on sound radiation protection, and ALARA principles, and not adjusted to account for failures to plan or control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning.

The licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. RWPs were reviewed to determine if they covered too many work activities to allow work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates. Additionally, the inspectors attended a station ALARA Committee meeting to assess the degree of oversight in outage dose management.

These reviews represented two required and one optional inspection samples.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed (directly or remotely) portions of the following three work activities that were being performed in high or locked high radiation areas that potentially represented significant radiological risk to workers:

- Reactor Head/Upper Internals Lift and Set Activities;
- Refuel Floor Support Activities;

- Radiography;
- Regenerative Heat Exchanger Activities; and
- Reactor Coolant Pump Motor Replacement.

The licensee's use of ALARA controls for these work activities was evaluated using the following:

The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews.

Job sites were observed to determine if workers were cognizant of work area radiological conditions, and utilized low dose waiting areas, and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays.

These reviews represented one required and one optional inspection sample.

b. Findings

No findings of significance were identified.

.5 Source Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to understand historical trends and current status of plant source terms. The inspectors discussed the plant's source term with health physics staff to determine if the licensee had developed a good understanding of the input mechanisms and the methodologies and practices necessary to achieve reductions in source term. The inspectors discussed exposure reduction initiatives taken for U2C16 such as system flushing and use of shielding. Results of the licensee's controlled CRUD burst initiative was reviewed for the outage to assess the adequacy of the cool-down and RCS cleanup process relative to predictions and historical data.

The inspectors reviewed the licensee's Source Term Reduction 5 Year Plan and discussed its status with health physics staff. The inspectors determined if specific sources had been identified by the licensee for exposure reduction initiatives and if priorities were established or being considered for the implementation of these actions.

These reviews represented one required and one optional inspection sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

Radiation worker and radiation protection technician performance was observed during work activities being performed in radiation areas, and locked high radiation areas, including work in the upper and lower Unit 2 Containment Building and radiography in the Auxiliary Building. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and the tools to be used for the job, by utilizing low dose waiting areas, and by demonstrating knowledge of the radiological conditions, and adhering to the ALARA requirements for the work activity. Job oversight, job support, and the communications provided by the radiation protection staff were also evaluated by the inspectors.

This review represented one required inspection sample.

b. Findings

No findings of significance were identified.

.7 Declared Pregnant Worker Program

a. Inspection Scope

The inspectors reviewed the licensee's procedure and process for monitoring the radiological exposure of declared pregnant workers to determine if the controls complied with the requirements of 10 CFR 20.1208.

This review represented one required sample.

b. Findings

No findings of significance were identified.

.8 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessment, audit, and field observation reports related to the ALARA program since the last inspection, to assess the licensee's ability to identify and correct problems.

The inspectors assessed the adequacy of the licensee's problem identification processes and verified that identified problems were entered into the corrective action program for resolution. This included post-outage ALARA critiques/lessons learned for exposure performance from the licensee's previous refueling outage in April 2005.

Corrective action reports generated since the end of the licensee's Unit 1 outage (U1C20) in April 2005, and those generated during U2C16 that related to the ALARA program were selectively reviewed, and staff members were interviewed to verify that follow-up activities were being conducted in a timely manner commensurate with their importance to safety and risk using the following criteria:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes; and
- Identification and implementation of effective corrective actions.

The licensee's corrective action program was also reviewed to determine if repetitive deficiencies in problem identification and resolution were being addressed.

These reviews represented two required and two optional inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

Cornerstone: Emergency Preparedness

.1 Emergency Preparedness Strategic Areas

a. Inspection Scope

The inspectors reviewed the licensee's records associated with the three EP performance indicators (PIs) listed below. The inspectors verified that the licensee accurately reported these indicators in accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC. Specifically, the inspectors reviewed licensee records associated with PI data reported to NRC for the period July 2005 through March 2006. Reviewed records included: procedural guidance on assessing opportunities for the three PI; assessments of PI opportunities during pre-designated Control Room Simulator training sessions, the 2005 biennial exercise, and several integrated emergency response facility drills; revisions of the roster of personnel assigned to key ERO positions; and results of ANS operability tests. The following PIs were reviewed:

- ANS;
- ERO Drill Participation; and
- Drill and Exercise Performance.

These activities completed three inspection samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Some minor issues were entered into the licensee's corrective action system as a result of inspectors' observations but are not discussed in this report.

b. Findings

No findings of significance were identified.

.2 Annual Sample Review (In-depth Review of Operator Workarounds)

a. Inspection Scope

The inspectors completed one annual baseline inspection sample regarding the cumulative effect of operator workarounds. The inspectors reviewed existing operator workarounds, identified Control Room deficiencies, and known degraded conditions that required compensatory actions by the operators to assess the cumulative effect on:

- 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.

The inspectors verified that potential workarounds were appropriately characterized in accordance with plant procedure PMP-4010-OWA-001, "Oversight and Control of Operator Workarounds."

In addition, the inspectors reviewed selected condition reports for identified problems associated with operator workarounds. The inspectors verified that the issues were entered into the corrective action program with the appropriate significance characterization and that corrective actions were appropriate and implemented as

scheduled. The inspectors reviewed the licensee's trending and assessment, CNP137 "Total Operator Burden," dated May 2006, which included operator workarounds, Control Room deficiencies, lit annunciators, and temporary modifications. The inspectors verified all existing burdens were included in the licensee's assessment and actions were in place to resolve known issues.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors completed one inspection sample regarding the semi-annual review of trends. The purpose of this review was to identify trends not previously identified or adequately addressed by the licensee that might indicate the existence of safety significant issues. The inspectors reviewed repetitive or closely related issues documented in the licensee's corrective action program, and in other processes and programs utilized by the licensee to track the status of plant issues. This review included but was not limited to condition reports, system health reports, self-assessment reports, and maintenance rule program reports. The review also included the licensee's Excellence Plan dated June 16, 2006.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

.1 Event Notification

a. Inspection Scope

The inspectors assessed the events and circumstances surrounding the licensee's declaration of a Notice of Unusual Event affecting Unit 2 on April 29, 2006 due to identified leakage from the RCS greater than 25 gpm.

On April 29, 2006, the licensee notified the NRC that for about 2.5 minutes the criteria for declaring an Unusual Event had been met. This was due to a charging pump suction header relief valve unexpectedly lifting while operators were aligning the Unit 2 RHR system for standby readiness. Additional details of this event are discussed in Section 1R14.1 of this report. Licensee personnel determined that the safety valve being open for 2.5 minutes resulted in a flow rate of approximately 48 gpm, which was greater than the 25 gpm identified RCS leak rate criteria for an Unusual Event. However, licensee personnel were only able to determine that the condition for declaring

the event was met after the leakage was stopped because of the short duration. Therefore, the Unusual Event was reported after the fact.

On April 30th, licensee personnel retracted the event notification because subsequent reviews of the event concluded that the criteria for an Unusual Event was not met, in that no RCS identified leakage occurred. Instead, the event was actually a diversion of 120 gallons of CVCS inventory, which was the result of system alignments by operators. Operators immediately recognized and terminated the event, and plant systems and components responded as designed.

The inspectors reviewed the event notification and subsequent retraction, and concluded that the basis for the retraction was reasonable.

b. Findings

A finding related to this event is discussed in Section 1R14.1 of this report. No other findings of significance were identified.

.2 (Closed) LER 05000316/2006-002-00, "Multiple Main Steam Safety Valve Test Failures"

During surveillance testing of the Unit 2 main steam safety valves (MSSVs) on May 13 and 14, 2006, the licensee identified that 5 of 20 MSSVs failed to meet the TS acceptance criteria for the lift setpoint. As a result of each MSSV test failure, the licensee entered the appropriate TS Limiting Condition for Operation and restored each valve to an operable condition within the TS allowed outage time. The valve lift test failures were due to metallic bonding between the Inconel X-750 valve disk and nozzle, resulting in an increase in each of the valve's lift setpoint.

The licensee performed an evaluation of the impact on the MSSV surveillance testing results on the transient and accident analysis described in the UFSAR and concluded that the out of tolerance conditions were bounded by the 110 percent secondary system design pressure assumed in the analysis. The inspectors reviewed the licensee's condition evaluation. The licensee entered this event into its corrective action program as CRs 06083002, 06083003, 06084029, 06084030, and 06084031. The licensee reported this as a condition prohibited by the plant's TS in accordance with 10 CFR 50.73(a)(2)(i)(B) and as a common cause of inoperability in accordance with 10 CFR 50.73(a)(2)(vii). This event did not constitute a violation of NRC requirements. This LER is closed.

.3 (Closed) LER 05000316/2006-001-00, "Failure to Comply with TS 3.6.2, Containment Airlocks."

On March 14, 2006, the Unit 2 lower containment outer airlock door was found by maintenance personnel to be not fully closed during the performance of a leak rate test. Both the inner and outer door closed indicator lights were lit. When the outer door's locking device was removed to verify the door closed, the maintenance personnel found that the outer door handwheel was not turned to the fully closed position. After fully

closing the handwheel, maintenance personnel satisfactorily tested the outer door. The handwheel had been turned enough to turn on the "door closed" light, but not far enough to seat the equalizing air valve. During this time, the inner door was fully operable so containment integrity was maintained.

The licensee determined that the last person to access the Unit 2 lower containment air lock did so on March 13th at about 1115. This was verified by the security key card reader report. The outer door hand wheel was locked and the key was controlled by the Operations Department. Because the outer airlock door was inoperable for greater than 1 hour and the inner door was not verified closed, TS 3.6.2, Condition A.1, was not met. The licensee reported this as a condition prohibited by the plant's TS in accordance with 10 CFR 50.73(a)(2)(i)(B).

The inspectors concluded that this violation of TS 3.6.2, Condition A.1, constitutes a violation of minor significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This LER is closed.

4OA5 Other Activities

.1 (Closed) URI 05000315/2005004-04, "Failure to Obtain NRC Approval for a Non-Code Compliant Weld Metal Overlay"

a. Inspection Scope

The inspectors reviewed actions taken by the licensee following the NRC's discovery that the licensee performed a weld overlay repair on a pressurizer safe end-to-pipe weld employing methodologies which deviated from those in the approved ASME Code Case –504-2 without obtaining NRC approval. The inspector also reviewed the NRC's Safety Evaluation Report issued in response to the subsequent relief request submitted by the licensee.

b. Findings

Introduction

The inspector identified a violation of 10 CFR 50.55a(g)(4) of minor significance for failure of the licensee to comply with an ASME Code Case –504-2 as approved for use in Regulatory Guide 1.147, as an alternative to the ASME Code Section XI repair requirements.

Description

On May 3, 2005, the inspector identified, through a conversation with the licensee and a review of documentation, that the licensee had performed a weld overlay on the pressurizer safe end-to-pipe weld (1-RC-9-01F). The overlay was performed using a methodology which deviated from that delineated in approved Code Case –504-2 without obtaining NRC approval.

During the period April 12 through April 18, 2005, the licensee completed a structural weld overlay on the pressurizer nozzle-to-safe end weld (1-PRZ-23). The overlay was performed as an alternative to ASME Code Section XI to effect the repair of a code rejectable flaw discovered in that weld during a UT exam performed as a licensee commitment in response to NRC Bulletin 2004-01. The licensee sought and was granted relief for an alternative application of, and exceptions to, Code Case –504-2, which was approved for generic use in Regulatory Guide 1.147, Revision 13. Specifically, an alternate application for nickel-based alloys and carbon steel was approved, as well as exceptions to paragraphs (b), (e), and (h) of –504-2. The docketed alternative to the repair requirements of ASME Code Section XI specifically identified the component affected (i.e., weld 1-PRZ-23) and described the extent of coverage of the overlay on the component affected.

The licensee elected to extend the length of the overlay repair of 1-PRZ-23 to encompass the adjacent stainless steel weld (1-RC-9-01F), which connected an austenitic stainless steel safe-end to a stainless steel elbow. Weld 1-RC-9-01F was of a different configuration, material, diameter, and wall thickness than 1-PRZ-23. The overlaying of the stainless steel weld was not specifically called out in the docketed relief requests previously identified, and additional relief was not requested for weld 1-RC-9-01F. As such, exceptions to methodologies required by Code Case –504-2, (i.e., paragraphs (b), which requires the use of low carbon (0.035 percent maximum) austenitic stainless steel for the reinforcement weld material and (e), which requires as-deposited delta ferrite measurements of at least 7.5 Ferrite Number for the weld reinforcement), were performed by the licensee, but were not specifically reviewed or approved by NRC staff for this application.

In response to NRC inquiries, the licensee docketed in its position paper, "Position Paper on Need for NRC ASME Code Relief" (AEP:NRC:5055-07) its rationale that the approved relief request for 1-PRZ-23 addressed any relief request requirements for the overlay deposited over weld 1-RC-9-01F. However, the licensee did subsequently submit relief request (ISIR-17) specifically for weld 1-RC-9-01F for NRC approval. NRR stated in the Safety Evaluation of relief request ISIR-17 that, while weld 1-RC-9-01-F was included within the structural overlay performed on weld 1-PZR-23, it was not included within the scope of Relief Request ISIR-15 (for weld 1-PZR-23).

Analysis

The inspector determined that the failure to obtain regulatory approval for the non-Code weld overlay repair of weld 1-RC-9-01F, a violation of 10 CFR 50.55a(g)(4)ii, was a performance deficiency warranting a significance evaluation in accordance with Appendix B, "Issue Dispositioning Screening," of IMC 0612, "Power Reactor Inspection Reports." In particular, the inspector compared this finding to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612 to determine whether the finding was minor and concluded that none of the examples listed in Appendix E accurately represented this example. As a result, the inspector compared this finding to the questions contained in Section 3, "Minor Questions," of Appendix B of

IMC 0612. The inspector determined that none of the questions could be answered in the affirmative. Specifically, the licensee subsequently submitted and was granted relief for the structural weld overlay of IRC-9-01F. As such, the inspector determined that the finding was of minor significance.

Enforcement

10 CFR Part 50.55a(g)(4)ii requires compliance with Section XI of the ASME Code or the ASME Code Cases identified in Regulatory Guide 1.147. ASME Code Section XI, IWA-4110(a), states that this Article provides rules and requirements for repair of pressure retaining components and their supports including appurtenances, subassemblies, parts of a component, and core support structures, by welding, brazing, or metal removal. Regulatory Guide 1.147 identified Code Case –504-2 as an NRC approved Code Case. Paragraph (b) of Code Case –504-2 requires that the reinforcement weld material shall be low carbon (0.035 percent maximum) austenitic stainless steel. Paragraph (e) of Code Case –504-2 requires as-deposited delta ferrite measurements of at least 7.5 Ferrite Number for the weld reinforcement. Contrary to these requirements, between April 12, 2005, and April 18, 2005, the licensee performed a structural weld overlay on pressurizer safe-end-to-pipe elbow stainless steel weld (1-RC-9-01) in accordance with PCI Project No. 900290, which did not use reinforcement weld material that was low carbon (0.035 percent maximum) austenitic stainless steel or ensure delta ferrite measurements of at least 7.5 Ferrite Number for the weld reinforcement and returned the component to service on April 22, 2005. Because the licensee subsequently submitted and was granted relief (TAC NO. MC8807 dated February 10, 2006) for the structural weld overlay of 1-RC-9-01F, the inspector concluded that this failure to comply with 10 CFR 50.55a(g)(4)ii constitutes a violation of minor significance and is not subject to enforcement action in accordance with Section IV of the NRC's enforcement policy. This URI is closed.

.2 (Closed) URI 05000315/316/2005004-01, "Potential External and Internal Flooding Impact on Safe Shutdown Equipment"

The inspectors completed a review of the issues associated with this open item. Three Green findings, one of which had an associated NCV, were documented in Section 1R06 of this inspection report. This URI is closed.

4OA6 Meetings

.1 Resident Inspectors' Exit Meeting

The inspectors presented the inspection results to Mr. M. Peifer and other members of licensee management at the conclusion of the inspection on July 6, 2006. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Proprietary information was examined during this inspection, but is not specifically discussed in this report.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Occupational Radiation Safety ALARA Program inspection during the licensee's Unit 2 refueling outage with Mr. R. Lingle and other members of licensee management on April 14, 2006.

- Inservice Inspection and URI 05000315/2005004-04 with Mr. C. Lane and other members of licensee management on April 20, 2006. The inspector returned proprietary information reviewed during the inspection and none of the potential report input discussed during the exit meeting was considered proprietary.

- Emergency Preparedness inspection with Mr. M. Peifer and other members of licensee management on June 30, 2006.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Brown, Radiation Protection Manager
D. Burgoyne, Regulatory Affairs Specialist
L. Bush, Site Senior License Holder
P. Carteaux, Emergency Preparedness Manager
R. Crane, Regulatory Affairs Specialist
H. Etheridge, Regulatory Affairs Specialist
D. Fadel, Acting Design Engineering Director
J. Gebbie, Acting Plant Engineering Director
C. Graffenius, Emergency Preparedness Coordinator
R. Hall, ISI Program Owner
J. Jensen, Support Services Vice President
P. Kohn, Engineering Programs Supervisor
C. Lane, Acting Engineering Programs Manager
S. Lies, System Engineering Manager
R. Lingle, Operations Manager
B. Mammoser, Mechanical Design Engineering Supervisor
R. Meister, Regulatory Affairs Specialist
K. Muller, BACC Program Coordinator
K. Newell, Engineering Supervisor
S. Partin, Work Control Manager
M. Peifer, Site Vice President
A. Robertson, Outage Manager
G. Sanders, Engineering Programs
M. Scarpello, Regulatory Affairs Supervisor
P. Schoepf, Engineering Design & Modifications Manager
D. Schroeder, Emergency Preparedness Coordinator
S. Simpson, Regulatory Affairs Manager
W. Wah, System Engineering
D. Walton, ALARA Supervisor
L. Weber, Plant Manager
V. Woods, Performance Assurance Manager

NRC

P. Tam, Project Manager, Plant Licensing Branch, NRR
J. Pulsipher, Containment and Ventilation Systems Branch, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000315/2006004-01 05000316/2006004-01	NCV	Potential External and Internal Flooding Impact on Safe Shutdown Equipment in the Lake Screen House (Section 1R06.b.1.)
05000315/2006004-02 05000316/2006004-02	FIN	Inadequate Preventive/Corrective Maintenance on Turbine Building Sump Overflow Check Valve 12-DR-129 (Section 1R06.b.2.)
05000315/2006004-03 05000316/2006004-03	FIN	Inadequate Functionality Evaluation for Degraded Check Valve Condition (Section 1R06.b.3)
05000316/2006004-04	NCV	Inadvertent Loss of Reactor Coolant System Inventory While Placing Emergency Core Cooling Systems in Standby Readiness (Section 1R14.1)
05000316/2006004-05	FIN	Heavy Load Dropped While Removing Vertical Bulkhead Blocks in Unit 2 Containment (Section 1R14.2)
05000316/2006004-06	NCV	Failure to Perform As-found Local Leak Rate Testing for a Containment Isolation Valve (Section 1R22.b.1)
05000316/2006004-07	NCV	Failure to Submit a Required Licensee Event Report (Section 1R22.b.2)
05000316/2006004-08	NCV	Failure to Establish Appropriate Technical Specification Surveillance Acceptance Criteria for the Emergency Diesel Generators (Section 1R22.b.3)

Closed

05000315/2006004-01 05000316/2006004-01	NCV	Potential External and Internal Flooding Impact on Safe Shutdown Equipment in the Lake Screen House (Section 1R06.b.1.)
05000315/2006004-02 05000316/2006004-02	FIN	Inadequate Preventive/Corrective Maintenance on Turbine Building Sump Overflow Check Valve 12-DR-129 (Section 1R06.b.2.)
05000315/2006004-03 05000316/2006004-03	FIN	Inadequate Functionality Evaluation for Degraded Check Valve Condition (Section 1R06.b.3)

05000316/2006004-04	NCV	Inadvertent Loss of Reactor Coolant System Inventory While Placing Emergency Core Cooling Systems in Standby Readiness (Section 1R14.1)
05000316/2006004-05	FIN	Heavy Load Dropped While Removing Vertical Bulkhead Blocks in Unit 2 Containment (Section 1R14.2)
05000316/2006004-06	NCV	Failure to Perform As-found Local Leak Rate Testing for a Containment Isolation Valve (Section 1R22.b.1)
05000316/2006004-07	NCV	Failure to Submit a Required Licensee Event Report (Section 1R22.b.2)
05000316/2006004-08	NCV	Failure to Establish Appropriate TS Surveillance Acceptance Criteria for the Emergency Diesel Generators (Section 1R22.b.3)
05000316/2006-002-00	LER	Multiple Main Steam Safety Valve Test Failures (Section 4OA3.2)
05000316/2006-001-00	LER	Failure to Comply with TS 3.6.2, Containment Airlocks (Section 4OA3.3)
05000315/2005004-04	URI	Failure to Obtain NRC Approval for a Non-Code Compliant Weld Metal Overlay (Section 4OA5.1)
05000315/2005004-01 05000316/2005004-01	URI	Potential External and Internal Flooding Impact on Safe Shutdown Equipment (Section 4OA5.2)

<u>Discussed</u>

05000316/2006009-02	NCV	Failure to Perform 10 CFR 50.59 Evaluation for Modification to the Unit 2 East Centrifugal Charging Pump (Section 1R19)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

PMP-5055-SWM-001; Severe Weather Guidelines; Revision 1
12-OHP-4022-001-010; Severe Weather; Revision 4
PMP-2291-SCH-002; Work Control Seasonal Readiness Process; Revision 2
PMI-5055; Winterization/Summerization; Revision 1
PMP-5055-001-001; Winterization/Summerization; Revision 2
12-IHP-5040-EMP-004; Plant Winterization and De-Winterization; Revision 6
CR 05250020; Action Tracking CR for Tracking Summer Readiness Actions for 2006
CR 05277047; 2005 Summer Readiness Critique

1R04 Equipment Alignment

D. C. Cook Units 1 and 2 TSs and Bases
D. C. Cook Updated Final Safety Analysis Report; Revision 20
12-OHP-4022-018-001; Loss of Spent Fuel Pit Cooling; Revision 8
OP-2-5142-49; Flow Diagram, Emergency Core Cooling (SIS); Revision 49
2-OHP-4021-008-002; Placing Emergency Core Cooling System in Standby Readiness; Revision 16
CR 03202018; Dry Boric Acid in the Packing Gland Area for 2-IMO-270. May Be a Body to Bonnet Leak
01-OHP-4030-132-217A; ESF Time Response - Safety Injection; Revision 7
01-OHP-4030-132-217B; ESF Time Response - Safety Injection; Revision 6
01-OHP-4030-132-217A; DG1CD Load Sequencing & ESF Testing; Revision 5
01-OHP-4030-132-217A, Attachment 25; Testing 1-QMO-225 for Safety Injection; Revision 5
01-OHP-4030-132-217B, Attachment 26; Testing 1-QMO-201 and 1-QMO-452 for Safety Injection; Revision 7
01-OHP-4030-132-217A, Attachment 26; Testing 1-QMO-200 and 1-QMO-451 for Safety Injection; Revision 6
01-OHP-4030-132-217B, Attachment 25; Testing 1-QMO-226 for Safety Injection; Revision 6
Unit 1 ESF Time Response Train A Safety Injection Tables; April 2005
Unit 1 ESF Time Response Train B Safety Injection Tables; March 2005
CR 06100064; 12-PP-31N Inboard Pump Bearing Has an Oil Leak; April 10, 2006
1-OHP-4021-032-008CD; Operating DG1CD Subsystems; Revision 9
Unit 1 Technical Data Book Figure 19.9; Diesel Generator Pot Settings; Revision 27
OP-1-5151C-50; Flow Diagram, Emergency Diesel Generator CD Unit 1; Revision 50
OP-1-5151D-65; Flow Diagram, Emergency Diesel Generator CD Unit 1; Revision 65

1R05 Fire Protection

D. C. Cook Fire Hazards Analysis, Units 1 and 2; Revision 12
D. C. Cook Fire Pre-Plan, Units 1 and 2; Revision 2
12-PPP-2270-066-001; Portable Fire Extinguisher Inspections; Revision 2

1R06 Flood Protection

D. C. Cook Updated Final Safety Analysis Report; Revision 20
OP-12-5125-49; Flow Diagram Station Drainage - Turbine Room, Unit 1 & 2; Revision 49
12-OHP-4022-001-009; Seiche; Revisions 1 and 2
Job Order 04048044-01; 12-DR-129 - Investigate and Repair Flap Valve; February 19, 2004
Job Order R0257482; Perform Annual Inspection of Turbine Building Sump Pit; July 7, 2005
Calculation MD-12-SD-001-S; Impact of Seiche on EDGs with Turbine Room Sump Flap Valve Failed; Revision 0
Calculation MD-12-SCRN-001-N; Screen House Internal Flood Levels; Revision 0
CR 03234074; CR 99-29555 Is Back-Log CAT.X CR that Should Potentially Be Considered a Condition Adverse to Quality
CR 04048044; During Inspection of 12-DR-129, the Valve Was Found Out of Position
CR 04321007; The Preventive Maintenance Program for the Turbine Sump Structure Needs to Be Revised to Include the 12-DR 129 Flapper Valve
CR 05158029; Determine If a Functional Test Needs to Be Created for 12-DR-129
CR 05179011; NRC Identified that CR 04321007 Was Closed Without the Action Taken That Was Documented as Taken, Which Was Create a PM Task for 12-DR-129
CR 05181220; NRC Resident Identified Incorrect Information in Condition Report 03234074 Operability Determination
CR 05210173; There Are Apparent Discrepancies Regarding the Flood Protection Elevation for the Plan
CR 05210173; Discrepancies Regarding the Flood Protection Elevation for the Plan
CR 05228056; During Job Order 02309012 Activity 2, the As-Found Visual Inspection of 12-DR-129 Identified a Slight Gap Between the Flapper Valve and the Valve Set
CR 05308066; Contrary to Section 10.6 of the UFSAR the Screen House Is Not Flood Protected to Elevation 595.0
CR 06065008; Engineering Gave the Operations Department Incorrect Information for the Operations Reviewer Comments for the Operability Call Documented in CR 04048044
CR 00800186; Cross-cutting Issue Regarding Timeliness of Repair to 12-DR-129

1R07 Heat Sink Performance (71111.07)

12-MHP-5030-016-001; Component Cooling Water Heat Exchanger Inspection, Cleaning and Tube Plugging; Revision 6
12-EHP-8913-001-002; Heat Exchanger Inspection; Revision 1
CR 05287070; Engineering to Provide Plugging Criteria for Auxiliary Feedwater Pump Room Coolers; October 14, 2005
CR 06110043; Inspection Found Tube Plugging in Excess of Limits
Work Order RO0266038; Component Cooling Water Heat Exchanger 2-HE-15W Inspection; March 30, 2006

Work Order RO0266452; Containment Spray Heat Exchanger 2-HE-18E Inspection; March 31, 2006

1R08 Inservice Inspection Activities (71111.08)

CALC-SD-050406-001; Revision 0; Cook Nuclear Plant Unit 2 - Calculation of Effective Degradation Years of Operation for Unit 2, April 6, 2005
CR 06096048; Boric Acid Residues of Unknown Origin Found Adjacent to Reactor Vessel Closure Head Penetration No. 42; April 6, 2006
CR 06095054; AREVA Contractor Violated Procedure Requirements; April 5, 2006
CR 06102054, 2-AFW-C-4034; Loose Nut on Double Bolt Pipe Clamp; April 12, 2006
CR 06104045, 2-OME-4; An Indication Was Identified in the Nozzle Base Material of 2-prz-24 During the Weld Overlay Examination; April 14, 2006
Liquid Penetrant Examination Data Report PT-06-002; E-RHRHEX-IN; March 24, 2006
Ultrasonic Examination Data Report UT-06-021, 2-SI-57-17; April 13, 2006
Ultrasonic Examination Data Report UT-06-022, 2-SI-57-17; April 13, 2006
Visual Examination Data Report VT-06-043, 2-AFW-C-4032; April 12, 2006

Documents Related to Code Pressure Boundary Welding

Job Order 03162051; Replace Welded Check Valve 2-PW-275; October 1, 2004
Radiographic Inspection Reports and Film; Welds OW-1 and OW-2; October 23, 2004
Flow Diagram OP-2-5128A; Reactor Coolant Unit 2; Revision 54
Job Order 04276008, 2-ILA-121-V1; Investigate and Repair Boron Leak; October 15, 2004
Liquid Penetrant Exam Report; Welds OW-1 and OW-4; October 26, 2004
Liquid Penetrant Exam Report; Welds OW-2 and OW-3; October 26, 2004
Equivalency Evaluation EE-2004-0402-SS-1; Revision 0, 2-ILA-121-V1; October 27, 2004
Job Order 04276040; Replace Equipment Caused By Pressure Surge 2-PP-50W; October 12, 2004
Radiographic Inspection Reports and Film; Welds OW-1, OW-2 and OW-2 R1; October 15, 2004
Liquid Penetrant Exam Reports; Welds OW-1, OW-2 and OW-2 R1; October 15, 2004
Weld Procedure Specification; 8.ITS Revision 2, Manual Gas Tungsten Arc and Shielded Metal Arc Welding; May 13, 2002.
PQR-136; ASME Code IX Procedure Qualification Record; Revision 1; February 10, 1976
PQR-219; ASME Code IX Procedure Qualification Record; Revision 1; January 16, 1990
PQR-256; ASME Code IX Procedure Qualification Record; Revision 1; August 7, 1989
PQR-258; ASME Code IX Procedure Qualification Record; Revision 1; August 7, 1989

Documents Associated with Boric Acid Corrosion Program

PMP-5030-001-001; Revision 10; Boric Acid Corrosion of Ferritic Steel Components and Materials; November 3, 2005
Completed Surveillance for U2 C15 NOP/NOT, 02-OHP-4030-001-002; Revision 16; November 8, 2004
Completed Surveillance for U2 FO4C NOP/NOT, 02-OHP-4030-001-002; Revision 16; November 28, 2004

Boric Acid Program Health Report, 4th Quarter 2005
CR 04328019; Unit 2 Pressurizer Manway was Found Leaking; November 23, 2004
CR 05139017; Blank Flange for 2-PW-282W Has Dry Boric Acid Leak; May 19, 2005
CR 05070003; 2-QCR-300 Has Several Ounces of Dry, Discolored Boric Acid Built Up on Valve Body; March 11, 2005
CR 06023019; Boric Acid Inactive Leakage Identified on Flange Upstream of 2-RH-106W; January 23, 2006
CR 06047004; Dry Inactive Boric Acid Buildup on Pipe Flange; February 16, 2006

Documents Associated with Nondestructive Testing Procedures

54-ISI-836; Ultrasonic Examination of Austenitic Piping Welds; Revision 9
54-ISI-601-01; Ultrasonic Examination of Nozzle Ferritic Base Materials Adjacent to Structural Weld Overlay; Revision 1
54-ISI-240; Visible Solvent Removable Liquid Penetrant Examination Procedures; Revision 40
WDI-ET-002; IntraSpect Eddy Current Inspection of Vessel Head Penetration J-Welds and Tube OD; Revision 7
WDI-UT-010; IntraSpect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal and Shear Wave; Revision 12
MRS-SSP-1483-AMP; Reactor Vessel Head Remote Visual Inspection for DC Cook Unit 2; Revision 3
12-QHP-5050-NDE-010; Radiographic Examination of Welds; Revision 2a

Documents Associated with Disposition of Relevant Indications

CR 04180026; 2-GCCW-R-137; Component Cooling Water Piping Not in Contact with Support as Designated; June 28, 2004
CR 04288060; 2-GRC-R-574; Support Has Bent Rod and Currently Is Not Bearing on the Support Member; October 13, 2004
CR 06016013; 2-ACS-R-913; One of Two Anchor Bolts Is Not Tight Against Base Plate; January 16, 2006

Corrective Action Documents As A Result of NRC Inspection

CR 06091026; AREVA Personnel Were Unfamiliar with the Requirements for Perform Liquid Penetrant Exam; March 31, 2006
CR 06090017; CR Evaluations for Section XI Support Deficiencies Did Not Address Section XI Requirements; March 31, 2006
CR 06090018; Pre-inspection Walkdown Initiated Corrective Action to Fix Degraded Condition Prior to Isi Exam Being Performed; March 31, 2006
CR 06097056; Evaluation for Boric Acid Corrosion Was Not Adequately Documented in the Pressurizer Manway Leak CR; March 28, 2006
CR 06092032; Construction Defects in ISI Supports; March 31, 2006
CR 06102032; Unnecessary Dose Accrued During Attempt to Perform Non-Destructive Examination; April 19, 2006
CR 06111038; Insulation Brackets Appear to Be in Contact with RV Head; April 21, 2006

Documents associated with URI

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CR 05117045; Unit 1 entered Mode 4 with an Unanalyzed Condition in Weld 1-RC-9-01F; April 21, 2005

1R11 Licensed Operator Requalification Program

Simulator Guide RQ-S-0520360101; Mitigate the Consequences of Loss of CRID; Revision 1
Simulator Guide RQ-S-0600260412; Respond to a Decrease in Feedwater Temperature Transient; Revision 0
Simulator Guide RQ-S-0570470412; Respond to Degraded Forebay Conditions; Revision 0

1R12 Maintenance Effectiveness

Maintenance Rule Scoping Document; Waste Disposal System Gaseous Waste; Revision 3
Maintenance Rule Evaluation Desktop Guide; Revision 1
Maintenance Rule a(1) Action Plan; Waste Disposal System - Gas; Revision 3
CR 06023001; Discovered Water in the Alternate Oxygen Monitor Flow Gage; January 23, 2006
CR 04278120; Changes Have Been Made to the Auto Gas Analyzer Without Design/Licensing Impact Evaluation; October 4, 2004
CR 05048025; Development of a Trouble Shooting Plan to Investigate and Correct the Auto Gas Analyzer Oxygen Monitor Conditions Described in CRs 04361004, 04361005, and 04361024; February 17, 2005
CR 05140069; A Declining Performance Trend for the Automatic Gas Analyzer Requires Focused, Interdisciplinary Action to Determine Apparent Cause and to Initiate Actions to Reduce the Rate of Occurrence; May 20, 2005
Maintenance Rule Scoping Document; Essential Service Water (ESW); Revision 8
System Health and Status Report for the Unit 1 Essential Service Water System; 1st Quarter 2006
System Health and Status Report for the Unit 2 Essential Service Water System; 1st Quarter 2006
CR 06096043; Unit 2 East Train of ESW Was Discovered to Be above the Established Maintenance Rule Unavailability Criteria and Needs to Be Presented to the Maintenance Rule Expert Panel for (a)(1) Consideration
Maintenance Rule (a)(1) Action Plan; Essential Service Water System; May 2006
CR 05221034; 2-ESW-141 Failed As-found Visual IST Check Valve Examination. Portions of Closure Spring and Teflon Washers Found Missing Which Presents an FME Issue
CR 05223074; Inspect and Replace as Necessary the U1 West ESW Strainer Basket Slide Gate Drive Nuts
CR 05223006; Delays in Return to Service

Two-year Unavailability Report for the Essential Service Water System; May 23, 2006
Maintenance Rule Reliability Failures (5/24/2004 to 5/24/2006) for Essential Service Water System; May 24, 2006

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

PMP-2291-OLR-001; On-Line Risk Management, Data Sheet 1; Work Schedule Review and Approval Form; Cycle 58, Week 12; April 2 through 8, 2006
PMP-2291-OLR-001; On-Line Risk Management, Data Sheet 1; Work Schedule Review and Approval Form; Cycle 58, Week 2; April 9 through 15, 2006
Infrequently Performed Test Evolution Briefing Guide for Switching and Repair of BC Disconnect Switch and Servicing Transformer 4; April 10, 2006
U2C16 Shutdown Risk Review Plant Operations Review Committee Presentation; March 6, 2006
PMP-4010-ODM-001; Operational Decision Making, Data Sheet 1; Operational Decision Making Checklist for Unit 1 Main Turbine Control Valves Have Moved Without Operator Demand; May 18, 2006
Shift Manager's Logs, May 17, 2006
CR 06139004; Main Turbine Control Valves Opened Causing a 12 Mw Increase in Power
CR 06137080; Observed the Main Turbine Control Valves Open About 3-5% from Previous Positions
1-OHP-SP-261; Isolation and Restoration of 1-CS-110, CVCS Cation Demineralizer Bypass Valve; Revision 0
CR 06141006; 1-CS-110 (CVCS Cation Demineralizer QC-101 Bypass Valve) Internals Failed While Opening Valve
OP-1-5130; Flow Diagram CVCS - Reactor Coolant Demineralization Unit 1

1R14 Personnel Performance During Non-Routine Plant Evolutions

CR 06086010; Lift Rig Assembly Failure
12-OHP-4050-FHP-014; Removal and Storage of the Reactor Missile Shields Cavity Covers and Seismic Restraints; Revision 8
12-OHP-4050-FHP-041; Reactor Missile Shield Cavity Cover and Seismic Restraint Installation; Revision 5
PMP-4050-CHL-001; Control of Heavy Loads; Revision 6
PMP-5020-MHP-001; Material Handling Program; Revision 5
CR 06119027; Charging Pump Suction Header Safety Valve 2-SV-56 Lifted
2-OHP-4021-008-002; Placing Emergency Core Cooling System In Standby Readiness; Revision 16
OP-2-5143-63; Flow Diagram Emergency Core Cooling (RHR); Revision 63
OP-2-5129A-36; Flow Diagram Reactor Letdown and Charging; Revision 36
OP-2-5129-48; Flow Diagram Reactor Letdown and Charging; Revision 48
02-OHP-4022-034-003; Recovery from Inadvertent Containment Isolation Phase A; Revision 7
Unit 2 Control Room Logs; April 25, 2006
CR 06115041; 2-CRV-470 Inadvertently Actuated During Train A LOOP/LOCA Testing
2-OHP-4030-232-217A; DG2CD Load Sequencing & ESF Testing
OP-1-98406-16; Component Cooling System Elementary Diagram; Revision 16

OP-1-98366-4; Solid State Reactor Prot. & Safeguard System Steam Generator Trips Trash #2 Elementary Diagram; Revision 4

1R15 Operability Evaluations

CR 06093032; Significant Increase in Vibrations Detected on 1-PP-7W
CR 06110053; During Performance of 1-OHP-4030-119-022W, West ESW Pump Performance Data, the 1H Bearing Vibration Exceeded the Action Level
CR 05325026; Potential Cable Degradation Question Regarding the Feed Cables from Auxiliary Transformer 1-TR1CD to 4 KV Breaker 1D5
Technical Data Book, Figure 1-15.2; Revision 80
1-OHP-4030-119-022W; West Essential Service Water System Test; April 4, 2006
CR 06097046; Modes 1-4 Aggregate Operability Determination Evaluation for Unit 2

1R19 Post Maintenance Testing

2-OHP-4030-2-3-052E; East Centrifugal Charging Pump Operability Test; Revision 0
Technical Data Book, Figure 2-15.1; Safety Related Pump Inservice Test Hydraulic Reference; Revisions 72 and 73
Technical Data Book, Figure 2-15.2; Safety Related Pump Inservice Test Vibration Reference; Revisions 63 and 64
CR 06107027; High Vibration on Unit 2 East Centrifugal Charging Pump (2-PP-50E), April 17, 2006
Job Order RO0250855-02; 2-XRV-220, Unit 2 AB Emergency Diesel Generator Starting Air Jet Assist Control Valve, Refurbish Actuator; April 5, 2006
Job Order 06045056; Replace Digital Reference Unit; April 1, 2006
Job Order RO25560505; Replace Voltage Regulator; April 1, 2006
Job Order RO282896-01; Unit 2 West Centrifugal Charging Pump; April 13, 2006
CR 06103032; Step Change on Vibrations on Pump and Motor Vibration Data Points for 2-PP-50W (West Centrifugal Charging Pump)
2-OHP-4030-203-052W; West Centrifugal Charging Pump Operability Test;
April 13, 2006
2-OHP-4030-219-022E; East Essential service Water System Test
ASME Code Oma-1988 Part 6; Inservice Testing of Pumps in Light-Water Reactor Power Plants
12-IHP-6030-032-004; Emergency Diesel Generator Woodward 2301A Analog Governor Tuning and Adjustment
2-OHP-4030-STP-027CD; CD Diesel Generator Operability Test (Train A)
2-OHP-4030-232-217A; DG2CD Load Sequencing & ESF Testing
2-OHP-4021-032-001CD; DG2CD Operation
CR 06103023; A Visible Crack Was Found in the Crown of the #2 Rear Bank (2RB) Piston of the 2CD EDG
CR 06108047; Unit 2 CD EDG Failed to Start on Receiving Start Signal From the Control Room
CR 06109009; 2-XRV-228 Pressure Reducing Valve Failed to Seat
CR 06109050; 2-OME-150CD 5F Cylinder Fuel Injector is Not Working. At 1750 kW 5F Cylinder Temp was at 116F

CR 06112038; When the Load Bank Breaker Was Closed, DG Frequency Lowered to Less Than 55 Hz and Did Not Recover. Local Speed Lowered to 320 RPM and Was Continuing to Lower.
CR 06114006; Performance Assurance Noted That an Informal Document Was Used to Provide Guidance for Flushing the Unit 2 CD EDG Fuel Oil System
CR06114045; Upon Loading the CD EDG to the Test Load Bank During LOOP/LOCA Testing, 2 Fuel Injectors Froze Up
Unit 2 Control Room Logs; April 18-26, 2006
Job Order 01080036-01; A Leak Was Identified on a Liner to Head Water Jumper on the Cylinder 2 Rear Bank of 2-OME-150-CD-EN

1R20 Refueling and Outage Activities

2-OHP-4021-001-004; Plant Cooldown from Hot Standby to Cold Shutdown; Revision 39
2-OHP-4021-001-001; Plant Heatup from Cold Shutdown to Hot Standby; Revision 39
2-OHP-4021-001-002; Reactor Start-Up; Revision 31
2-OHP-4021-001-006; Power Escalation; Revision 28
2-OHP-4021-002-013; Reactor Coolant System Vacuum Fill; Revision 7
PMP-4100-SDR-001; Plant Shutdown Safety and Risk Management; Revision 12
2-OHP-4021-002-005; RCS Draining; Revision 25
ORAM Desktop Guide; Revision 16
CR 06118034; 60-100 Drops per Minute Leak 2-SV-334-4, Non-essential Service Water from RCP #4 Motor Air Coolers 2-HE-69-4A and 2-HE-69-4B Outlet Safety Valve
CR 06113019; 2-QRV-20 Will Not Indicate Full Closed
CR 06116008; Dry Boric Acid Was Identified on 2-RH-142, West RHR to Upper Containment Spray Ring Header Containment Isolation Check Valve. The Dry Boric Acid is Also Rusty in Color
PMP-5030-001-001, Data Sheet 1; Boric Acid Inspection List; Revision 10; May 3, 2006
CR 06116003; Loose Mirror Insulation and Insulation Band on Non-essential Service Water Supply Line to HV-CUV-4
CR 06115043; While Performing Train A LOOP/LOCA Testing, 2-ECR-17,18,27,28 Failed to Open When Taking the Train B Containment Hydrogen Sample Bypass Switch, 2-101-BPB, to 'Bypass'
CR 06110047; Vacuum Fill Procedure Not Updated for ITS
CR 06101039; Manual Bypass Switch for CRID II Inverter Is Locked Up and Cannot Be Moved
CR 06100045; Valve 2-SI-189 Was Unable to be Pressurized While Attempting As-Found LLRT During U2C16 Refueling Outage
CR 06097043; 2-CRID-III Inverter Switch 1 Is Broke
CR 06117083; Performance Assurance Found and Removed Items and Debris From Containment During the U2C16 Containment Closeout Inspection
CR 06087013; Unit 2 Reactor Cavity Sealing Surface Has Several Indications That May Be Leakage Sources
CR 06087068; Reactor Vessel Annulus Gap Measurement Exceeds Maximum Difference Per 12-OHP-4050-FHP-018 Data Sheet 1
CR 05107013; While Draining to Mid Loop, Discovered the Vent Hoses at 1-RC-148 and RC-149 were Erroneously Connected to the Tee at the Top of the Pressurizer
OHI-6100, Attachment 5B; RCS/PAR Cooldown Record; Revision 10; March 24, 2006

1R22 Surveillance Testing

NRC Regulatory Guide 1.163; Performance-Based Containment Leak-Test Program; September 1995
Nuclear Energy Institute 94-01; Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J; Revision 0; July 16, 1995
EHI 5300; D. C. Cook Nuclear Plant Containment Leakage Rate Testing Program (Appendix J); Revision 3
CR 06100045; Valve 2-SI-189 Was Unable to Be Pressurized While Attempting As-Found LLRT Testing During U2C16 Refueling Outage
CR 06116056; Minimum Path Leak Rate for U2C16 per 2-EHP-4030-234-203 Exceeded L_a
CR 06101012; Valve 2-SI-189 Was Disassembled and Internal Visual Inspection Performed Prior to Performance of As-Found Local Leak Rate (B&C) Test
CR 06151087; Failure to Comply with TS SR 3.6.1.1 Was Never Evaluated in CRs 06101012 and 06100045
2-EHP-4030-203-208; ECCS Flow Balance - Boron Injection System; Revision 8
Technical Data Book, Figure 2-15.1; Safety Related Pump Inservice Test Hydraulic Reference; Revisions 72 and 73
Technical Data Book, Figure 2-15.2; Safety Related Pump Inservice Test Vibration Reference; Revisions 63 and 64
CR 06106012; 2-PP-50E, East Centrifugal Charging Pump Was Shut Down Because of High Vibration on the Inboard Bearing Horizontal (7H)
Infrequently Performed Test Evolution Briefing Guide for Unit 2 Integrated Leak Rate Test of the Containment; April 10, 2006
2-OHP-4030-208R, Attachment 1; Residual Heat Removal Suction and Discharge Check Valve Test; Revision 6; April 3, 2006
2-OHP-4030-208R, Attachment 8; Accumulator Check Valve Test; Revision 6; April 3, 2006
2-OHP-4030-219-022V; ESW Flow Verification; Revision 5; April 18, 2006
2-EHP-4030-202-386; Multiple Rod Drop Measurements; Revision 5; May 5, 2005
12-EHP-4030-002-316; Subcritical Physics Tests with Subcritical Rod Worth Measurement; Revision 1; May 5, 2006
2-OHP-4030-256-017T; Turbine Driven Auxiliary Feedwater System Test; Revision 0; April 30, 2006
CR 06120017; Turbine Driven Auxiliary Feedwater Pump Test Valve 2-FRV-256 IST Stroke Time Was Too Fast
CR 06119058; During Performance of 2-OHP-4030-256-017T, Attachment 1, Two of Four Steam Traps Were Broken and Bypassed
2-OHP-4030-232-217A; DG2CD Load Sequencing & ESF Testing
CR 06123052; SWRM Constants for the U2C16 Startup are Being Revised in Order to Account for the Impact of the Delayed U2C16 Startup on Isotopic Inventory of the Core and SS and a Minor Input Error With the Axial Weighting Functions
CR 06166024; Difficulties Encountered During Unit 2 Cycle 16 Physics Testing (12-EHP-4030-002-316, 'Subcritical Physics Tests with Subcritical Rod Worth Measurement')
Unit 2 Control Room Log; May 5, 2006
D. C. Cook Unit 2 Cycle 16 Shutdown Margin Calculation Package

AEP Design Information Transmittal, Unit 2 Cycle 15/16 Boron Requirements for Refueling Operations and Beginning of Cycle Modes 3 through 5

1R23 Temporary Modifications

Simplified Design Packet for 2-TM-06-13-RO; Tap Changes for the Unit 2 Auxiliary Transformers 2-TR2AB and 2-TR2CD During the 2006 Unit 2 Refueling Outage (U2C16); Revision 0
Job Order R0267225-12; 2-TR2AB: Change Tap Position Prior to Backfeed
Job Order R0267225-22; 2-TR2CD: Change Tap Position Prior to Backfeed
Job Order R0267225-13; 2-TR2AB: Change Tap Position After Backfeed
Job Order R0267225-23; 2-TR2CD: Change Tap Position After Backfeed
D. C. Cook Updated Final Safety Analysis Report; Revision 20

1EP2 Alert and Notification System (ANS) Testing

Berrien County Early Warning Siren System Operation Manual; December 1, 2005
D. C. Cook Monthly Early Warning System Test Records; November 2004 through April 2006

1EP3 Emergency Response Organization (ERO) Augmentation Testing

D. C. Cook Nuclear Plant Emergency Plan, Sections B. Table 1 and N.1.b; Revision 21
PMP-2080-EPP-100; Emergency Response; Revision 7
EPAM-2080-500; Drills and Exercises; April 8, 2004
RMT-2080-EOF-001, Attachment 1; EOF Activation Checklist; Revision 9
RMT-2080-OSC-001, Attachment 1; OSC Activation Checklist; Revision 4
RMT-2080-TSC-001, Attachment 1; TSC Activation Checklist; Revision 6
D. C. Cook Nuclear Plant Emergency Response Organization Phone Directory; Revision 40
Current Position Assignment Report; April 17, 2006
SA-2004-SPS-017-QH; August 24, 2004, ERO Unannounced Off Hours Drill; September 13, 2004
CR 04238030; During August 24, 2004, Off-Hours Call-in Drill, Dialogics Provided Conflicting Message; August 25, 2004
CR 05131072; The TSC Was Activated 5 Minutes Late during the May 10, 2005, Unannounced Drill; May 11, 2005
CR 05174016; Track Unannounced Off-Hours ERO Augmentation Drill for Team 4 Conducted on June 23, 2005
CR 05320013; Document Results of ERO Semi-Annual Unannounced Off-Hours Augmentation Drill Conducted November 15, 2005; November 15, 2005

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

RMA-2080-EPA-008; Emergency Plan Management; Revision 2
PA-04-13; Performance Assurance Audit of the Emergency Plan; August 31, 2004
PA-05-07; Emergency Plan Audit Report; August 29, 2005
SA-2004-SPS-016-P; Site Protective Services/Emergency Planning Self-Assessment; October 29, 2004

CR 04210064; Emergency Plan Training and Procedural Guidance Regarding the Ability to Use Sheltering as a Protective Action Recommendation Needs Reinforcement and Clarification; July 28, 2004
CR 04113027; Emergency Preparedness Assessment Report; April 24, 2004
CR 04218028; Performance Assessment Identified Examples Where a 10 CFR 50.54(q) Evaluation Was Not Found; August 5, 2004
CR 05188964; Perform Emergency Preparedness Quick Hit Self-Assessment; June 22, 2005
CR 05195040; Inappropriate Actions Were Not Identified in the Corrective Action Program in a Timely Manner; July 14, 2005
CR 05202014; Condition Reports Need to Be Initiated to Track Filling Open ERO Positions; July 20, 2005

<u>2OS1</u> <u>Access Control to Radiologically Significant Areas</u>
<u>2OS2</u> <u>ALARA Planning and Controls</u>

12-THP-6010-RPP-006; Radiation Work Permit (RWP) Processing; Revision 23
12-THP-6010-RPP-014; Total Effective Dose Equivalent Evaluation; Revision 7
12-THP-6010-RPP-016; Radiation Protection Department Shift Responsibilities; Revision 12
12-THP-6010-RPP-104; Tissue and Control of Special Dosimetry; Revision 7
12-THP-6010-RPP-121; Dose Monitoring for Declared Pregnant Women (DPW); Revision 2
12-THP-6010-RPP-206; Internal Dose Assessment and Calculation; Revision 5
12-THP-6010-RPP-420; Radiological Controls for Radiography; Revision 3
12-THP-6010-RPP-421; Radiological Controls for Steam Generator Maintenance; Revision 1
CR 05087013; RCS Activity Increase Following Forced Oxidation During U1C20 Shutdown; March 28, 2005
CR 05096017; Dose Estimate for U1C20 Scaffold RWP Calculated in Error; April 6, 2005
CR 05137035; ALARA Suggestions from Post Outage Operations Job Review; March 17, 2005
CR 06061053; Radiation protection Quick Hit Self-Assessment - ALARA Program; March 2006
CR 06026009; Man-Hour Estimates Provided to the ALARA Group Do Not Reflect Actual Wrench Time; January 26, 2006
CR 06088048; During 50% In-progress Review for U2C16 Temporary Shielding, It Was Determined That the Dose Estimate Would Be Exceeded Prior to Completion of All Temporary Shielding Activities; March 21, 2006
CR 06089038; The 50% ALARA In-Progress Review of RWP 062187 Indicates That the Original Dose Projection Will Be Exceeded by Approximately 18%; March 30, 2006
D. C. Cook Nuclear Power Plant Dose Reduction 5 Year Proposed Plan - 2006; April 2006
Historical Outage Dose Information for U1C19, U1C20, U2C14, and U2C15
Performance Assurance Audit PA-06-01; Radiation Protection; March 06, 2006
Primary/Secondary/Balance of Plant Chemistry Control (U2C16) Outage Script; Revision 0
PMI-6010; Radiation Protection Plan; Revision 15
PMP-6010-ALA-001; ALARA Program - Review of Plant Work Activities; Revision 15
PMP-6010-RPP-001; General Radiation Worker Instructions; Revision 7
PMP-6010-RPP-006; Radiation Work Permit Program; Revision 8

RWP Package 05-1102; U1C20 Remove/Replace Reactor Head and Upper Internals
RWP Package 051105; U1C20 Refuel Restoration Work
RWP Package 051145; U1 C20 Valve Maintenance and Repair
RWP Package 051175; U1C20 Regenerative Heat Exchanger Locked High Radiation Area
RWP Package 062102; U2C16 Remove and Replace Reactor Head, Upper Internals, and Reactor Head O-Rings
RWP Package 062105; U2C16 Refuel Restoration Work
RWP Package 062106; U2C16 Control Rod Drive Mechanism Head Inspections
RWP Package 062108; U2C16 Untrained Workers and Their Escorts
RWP Package 062123; U2C16 Temporary Shielding
RWP Package 062140; U2C16 Containment Remove, Reinstall and Modify Insulation
RWP Package 062142; U2C16 Containment Install, Modify and Remove Scaffold
RWP Package 062143; U2C16 Perform In-Service Inspection Activities in Containment
RWP Package 062145; U2C16 U2 Containment Valve Maintenance and Repair Work
RWP Package 062151; U2C16 Reactor Coolant Pump Seal Maintenance Activities
RWP Package 062175; U2C16 Regen Heat Exchanger
RWP Package 062176; U2C16 Reactor Coolant Drain tank Locked High Radiation Area Activities
RWP Package 062187; U2C16 Under Reactor Vessel Inspections
RWP Package 062190; U2C16 Pressurizer Weld Overlay
U1C20 Outage Final Report; April 2005
U2C15 Outage Final Report; October 2004
U2C16 RWP Daily Dose Total Reports for April 10 - 14, 2006
U2C16 RWP Summary and Associated Time/Dose Estimates; undated
Whole Body Counts, Miscellaneous; dates Varied

4OA1 Performance Indicator (PI) Verification

PMP-7110-PIP-001; Alert and Notification System Reliability; July 2005 through March 2006
Desktop Guide for Emergency Preparedness Performance Indicators; Revision 5
Sample of Berrien County Monthly Early Warning System Tests Reports; July 2005 through March 2006
Sample of End of Quarter ERO Drill Participation Records; July 2005 through March 2006
Sample of Records of Opportunities for the Drill/Exercise Performance PI; July 2005 through March 2006

4OA2 Problem Identification and Resolution

Listing of Operator Burdens for Unit 1 and 2; May 3, 2006
Cook Nuclear Plant Excellence Plan Indicator CNP.137 Total Operator Burden; May 2006
Excellence Plan Management Review Meeting; June 16, 2006
Event Code Report; January 2006
Recovery Plan Performance Indicators; June 27, 2006

4OA3 Event Response

Event Notification #42536; April 29, 2006
Retraction of Event Notification #42536; April 30, 2006
LER 05000316/2006-001-00; Failure to Comply with TS 3.6.2, Containment Airlocks; May 11, 2006
CR 06073017; Unit 2 Lower Outer Airlock Door Was Found Not Fully Closed
LER 05000316/2006-002-00; Multiple Main Steam Safety Valve Test Failures; May 19, 2006
CR 06083002; Main Steam Safety Valve 2-SV-2A-1 Failed As-found Testing Prior to U2C16 Outage
CR 06083003; Main Steam Safety Valve 2-SV-1A-3 Failed As-found Testing Prior to U2C16 Outage
CR 06084029; Valve 2-SV-1B-1 Lifted Outside Acceptance Criteria During Trevi Testing
CR 06084030; Valve 2-SV-2A-4 Lifted Outside Acceptance Criteria During Trevi Testing
CR 06084031; Valve 2-SV-1B-4 Lifted Outside Acceptance Criteria During Trevi Testing

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CFR	Code of Federal Regulations
CR	Condition Report
CVCS	Chemical and Volume Control System
U1C20	D. C. Cook's 20th Unit 1 Refueling Outage
U2C16	D. C. Cook's 16th Unit 2 Refueling Outage
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EHI	Engineering Head Instruction
EP	Emergency Preparedness
ERO	Emergency Response Organization
ESF	Engineered Safety Features
ESW	Essential Service Water
FIN	Finding
gpm	Gallons-Per-Minute
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
IST	Inservice Testing
ITS	Improved Standard Technical Specifications
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOOP	Loss of Offsite Power
MSSV	Main Steam Safety Valves
NGVD	National Geodetic Vertical Datum
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PI	Performance Indicator
psig	Pounds Per Square Inch Gauge
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWP	Radiation Work Permit
SDP	Significance Determination Process
SSC	Structures, Systems, and Components
SR	Surveillance Requirement
SRA	Senior Reactor Analyst
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination