July 29, 2004

Mr. Thomas Coutu
Site Vice President
Kewaunee Nuclear Power Plant
Nuclear Management Company, LLC
N490 State Highway 42
Kewaunee, WI 54216-9511

SUBJECT: KEWAUNEE NUCLEAR POWER PLANT
NRC INTEGRATED INSPECTION REPORT 05000305/2004004

Dear Mr. Coutu:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Kewaunee Nuclear Power Plant. The enclosed integrated inspection report documents the inspection findings which were discussed on July 1, 2004, with Mr. K. Hoops and other members of your staff.

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

Based on the results of this inspection, there were three self-revealed findings of very low safety significance (Green). These findings involved violations of NRC requirements. However, because these violations were of very low safety significance, non-willful and non-repetitive, and because the violations were entered in your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, a licensee-identified violation is listed in Section 4OA7 of this report.

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 copies 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 NRC Resident Inspector Office at the Kewaunee 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/

Mohammed A. Shuaibi, Acting Chief
Branch 5
Division of Reactor Projects

Docket No. 50-305
License No. DPR-43

Enclosure: Inspection Report 05000305/2004004
w/Attachment: Supplemental Information

cc w/encl: J. Cowan, Executive Vice President,
Chief Nuclear Officer
Plant Manager
Manager, Regulatory Affairs
J. Rogoff, Vice President, Counsel & Secretary
D. Molzahn, Nuclear Asset Manager,
Wisconsin Public Service Corporation
L. Weyers, Chairman, President and CEO,
Wisconsin Public Service Corporation
D. Zellner, Chairman, Town of Carlton
J. Kitsembel, Public Service Commission of Wisconsin

DOCUMENT NAME: C:\Karen's Documents\ML042150256.wpd

To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	RIII	RIII		
NAME	JCameron:dtp	MShuaibi		
DATE	07/28/04	07/29/04		

OFFICIAL RECORD COPY

ADAMS Distribution:
WDR
DFT
CFL
RidsNrrDipmIipb
GEG
HBC
JFL
CAA1
C. Pederson, DRS (hard copy - IR's only)
DRPIII
DRSIII
PLB1
JRK1
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No.:	50-305
License No.:	DPR-43
Report No.:	05000305/2004004
Licensee:	Nuclear Management Company, LLC
Facility:	Kewaunee Nuclear Power Plant
Location:	N 490 Highway 42 Kewaunee, WI 54216
Dates:	April 1 through June 30, 2004
Inspectors:	R. Krsek, Senior Resident Inspector P. Higgins, Resident Inspector S. Burgess, Senior Reactor Analyst J. Cameron, Project Engineer R. M. Morris, Resident Inspector, Point Beach N. Shah, Resident Inspector, Braidwood S. Unikewicz, Office of Nuclear Reactor Regulation R. K. Walton, Operator License Examiner M. Jordan, NRC Consultant
Approved By:	M. Shuaibi, Acting Chief Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000305/2004004; 04/01/2004 - 06/30/2004; Kewaunee Nuclear Power Plant; Operability Evaluations and Event Follow-up.

This report covers a 3-month period of baseline resident inspection. The inspections were conducted by the residents and Region-based inspectors, with assistance on technical issues from the Office of Nuclear Reactor Regulation staff. The inspections identified three self-revealed Green findings, all associated with non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process (SDP)." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions", was self-revealed on June 16, 2004, when licensee personnel discovered leakage from the 'B' residual heat removal (RHR) pump seal when the pump was stopped following the performance of a surveillance procedure on the 'B' RHR train. Plant personnel determined the leakage to be in excess of that specified in the plant's System Integrity Program for leakage from emergency core cooling systems outside containment. The leakage was also in excess of the amount of leakage assumed in the Updated Safety Analysis Report, Chapter 14, for calculation of control room habitability doses and offsite exposures. The inspectors subsequently determined, from interviews with licensee personnel and a review of the licensee's corrective action program and work order history, that excessive RHR seal leakage has occurred since the late 1980s. However, past corrective actions have not been effective to correct this condition adverse to quality.

  The licensee performed a prompt engineering review to ensure that no immediate catastrophic failure mechanism for the RHR seal existed. The licensee also performed a prompt engineering review of the impact of the estimated leakage on the control room habitability doses, as well as the offsite doses, and determined no exposure limits would be exceeded. The licensee took actions to immediately stop the leakage and plans to replace the RHR pump seal during the next refueling outage.

  This self-revealed finding was more than minor because the finding affected the cornerstone objective of Reactor Safety/Barrier Integrity. The inspectors evaluated the finding using Inspection Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor

Inspection Findings for At-Power Situations," Phase 1 screening, and determined that the finding was of very low safety significance. (1R15.1)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was self-revealed on January 15, 2004, when licensee inspection of the 'A' and 'B' safety injection pump lube oil coolers identified silt and lake grass accumulation at the tube pass inlets. Significant fouling of the safety injection pump lube oil coolers with lake grass had been identified by the licensee as early as 1992 when the coolers were first opened and inspected. The licensee failed to enter the results of those inspections in the corrective action program when fouling was identified, until 2001. When the issue was entered into the corrective action program in 2001, following an inspection by plant personnel, the associated evaluation did not adequately address the issue and corrective actions were not taken in a timely manner to address the issue.

  The licensee initiated numerous corrective actions to address the root and contributing causes identified during the root cause evaluation of this event. Some of those actions included: replacing the old safety injection pump lube oil coolers with coolers of a new design; performing an extent of condition review of other service water systems prior to plant restart in January 2004 to ensure no similar immediate issues existed; sharing lessons learned from this event with all plant staff; and performing a prioritization review of all outstanding plant design modifications.

  The inspectors verified the licensee's past operability analysis for the safety injection pumps. The inspectors evaluated the finding using the results of that analysis and Inspection Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening, and determined that the finding was of very low safety significance. (4OA3.2)

- Green. A finding of very low safety significance associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when the licensee discovered fouling of the safety injection pump lube oil coolers in January 2004. The licensee determined that evidence of the fouling had been present since the first inspection of the coolers in 1992. The licensee performed that first inspection as part of its actions to comply with Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." However, no acceptance criteria were included in the licensee's procedures developed to implement the commitments of Generic Letter 89-13 for these coolers to ensure that this activity had been satisfactorily accomplished.

  The licensee initiated several corrective actions to address this issue, some of which included: establishing appropriate acceptance criteria for the safety injection lube oil coolers; developing a recovery plan for the licensee's Generic Letter 89-13 program and categorizing the program health in a red status; designating a single program owner to the Generic Letter 89-13 program; and reviewing other procedures utilized to implement the licensee's Generic Letter 89-13 program to verify specific acceptance criteria are contained in the procedures.

The inspectors verified the licensee's past operability analysis for the safety injection pumps. The inspectors evaluated the finding using the results of that analysis and Inspection Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening, and determined that the finding was of very low safety significance. (4OA3.3)

B. Licensee-Identified Violation

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

REPORT DETAILS

Summary of Plant Status

The plant was operated at or near full power for most of the inspection period, except for brief periods when operators reduced power to facilitate quarterly main generator turbine valve and auxiliary feedwater system required testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

During periods of potentially adverse weather effects such as high winds and tornadoes, the inspectors reviewed the facility's design and the licensee's procedures to verify that structures, systems and components would remain functional when challenged by these adverse weather conditions. This activity completes one inspection procedure sample.

Additionally, the inspectors walked down all areas outside the plant structures within the protected area, as well as the plant switchyard, to determine whether equipment or material, not designed for tornado wind loadings, could result in unacceptable impacts to plant safety related structures, systems or components. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed partial walkdowns of the following three systems, completing three inspection procedure samples, to verify that the systems were correctly aligned to perform their design safety function:

- 'B' Internal Containment Spray Train, while the opposite train of Internal Containment Spray was out of service for a routine quarterly surveillance;
- 'B' Emergency Diesel Generator Train and the associated Train 'B' 4160 Volt Distribution System, while the opposite train Emergency Diesel Generator was out of service during installation of a design modification; and
- 'B' Residual Heat Removal Train, after the system was returned to service following a routine quarterly surveillance.

In preparation for the walkdowns, the inspectors reviewed the system lineup checklists, normal operating procedures, abnormal and emergency operating procedures, and system drawings to verify the correct system lineup. During the walkdowns, the inspectors also examined valve positions and electrical power availability to verify that valve and electrical breaker positions were consistent and in accordance with the licensee's procedures and design documentation. The inspectors also observed the material condition of the equipment. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed fire protection walkdowns of the following six plant areas, completing six inspection procedure samples:

- Fire Zone AX-23A, Containment Spray Pump Area;
- Fire Zones TU-92 and TU-93, Diesel Generator 1-B and Diesel Generator 1-B Day Tank Room;
- Fire Zone TU-22, Turbine Building-Mezzanine;
- Fire Zones TR-84 and TR-85, Main Transformer A and B Phase Areas;
- Fire Zones TR-86 and TR-83, Main Transformer C Phase and Reserve Auxiliary Transformer Areas; and
- Fire Zones TR-80 and TR-81, Main Auxiliary Transformer and Tertiary Auxiliary Transformer Areas.

During the walkdowns, the inspectors focused on the availability, accessibility, and condition of fire fighting equipment; the control of transient combustibles and ignition sources; and the materiel condition of installed fire barriers. The inspectors selected fire areas for inspection based on the overall contribution to internal fire risk, and the potential to impact equipment that could initiate a plant transient. The inspectors verified that fire response equipment was in the designated location and available for immediate use without obstruction; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and that passive features such as fire doors, dampers, and penetration seals were in satisfactory condition. The inspectors verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R11 License Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Observation of Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensee training personnel evaluate an operating crew during an accident scenario and subsequently observed the operating crew critique their performance. The inspectors observed the crew and verified the following attributes of crew performance: communications, alarm response, emergency operating procedure usage, component operations and emergency plan classifications. The inspectors reviewed the scenario for operational validity and risk significance. The inspectors discussed scenario observations and crew evaluations with the licensee trainers. This constitutes one quarterly inspection sample. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the implementation of the maintenance rule (10 CFR 50.65) for the systems listed below, completing two inspection procedure samples:

- Radiation Monitoring System; and
- 4160 Volt Electrical Supply and Distribution System.

The inspectors verified that the licensee identified, entered, and scoped component and equipment failures within the maintenance rule requirements. The inspectors also verified that the systems and equipment were properly categorized and classified as either "(a)(1)" or "(a)(2)" in accordance with the maintenance rule." The inspectors reviewed a sample of station logs, maintenance work orders, maintenance rule evaluations, unavailability records, and a sample of condition reports to verify that the licensee identified issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. Additionally, the inspectors reviewed the licensee's performance criteria to verify that the criteria adequately monitored equipment performance. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and assessment of plant risk, scheduling, and configuration control during the following planned and emergent work activities, completing four inspection procedure samples:

- Safety Monitor Risk Assessment for April 5 through 9, 2004;
- Safety Monitor Risk Assessment for April 26 through 30, 2004;
- Safety Monitor Risk Assessment for June 1 through 4, 2004; and
- Safety Monitor Risk Assessment for June 14 through 18, 2004.

In particular, the inspectors evaluated the licensee's planning and management of maintenance, and verified that shutdown and on-line risk was acceptable and monitored in accordance with the requirements of 10 CFR 50.65(a)(4). Additionally, the inspectors compared the assessed risk configuration against the actual plant conditions, emergent plant conditions and any in-progress evolutions or external events to verify that the assessment was accurate, complete, and appropriate. The inspectors also reviewed licensee actions to address increased on-line risk during these periods to verify that the actions were in accordance with approved administrative procedures. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Historical Residual Heat Removal Pump 'B' Mechanical Seal Leakage

a. Inspection Scope

The inspectors reviewed the operability evaluation associated with the excessive mechanical seal leakage from the 'B' residual heat removal (RHR) pump when the pump was stopped following performance of the Technical Specification (TS)-required quarterly surveillance.

The inspectors reviewed design basis information, the Updated Safety Analysis Report (USAR), TS requirements, System Integrity Program, and licensee procedures to verify the technical adequacy of the operability evaluation. In addition, the inspectors verified that compensatory measures were implemented as required. The inspectors verified that system operability was properly justified in accordance with Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," and that the system remained available, such that no unrecognized increase in risk occurred. Finally, the inspectors reviewed work order and corrective action program history associated with previous failures of the RHR removal pump mechanical seals.

This activity constituted one inspection procedure sample. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

Introduction: A finding of very low safety significance associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions”, was self-revealed when on June 16, 2004, licensee personnel discovered leakage from the ‘B’ RHR pump mechanical seal when the pump was stopped, following the performance of the TS-required surveillance procedure on the ‘B’ RHR train. Plant personnel determined that this leakage was in excess of that specified in the plant’s System Integrity Program for leakage from emergency core cooling systems outside containment. Plant personnel also determined that the leakage was in excess of the amount assumed in Chapter 14 of the USAR for the calculation of control room habitability doses and offsite exposures. The inspectors subsequently determined from a review of the licensee’s corrective action program and work order documentation, that excessive RHR seal leakage has occurred since the late 1980s. However, past corrective actions have not been effective to correct this condition adverse to quality.

Description: On June 16, 2004, during a routine quarterly surveillance of the ‘B’ RHR train, after the RHR pump was stopped, licensee personnel reported that the pump seal was leaking excessively. The licensee estimated that the seal leakage was approximately one gallon per minute (gpm) or 60 gallons per hour (gph). This was greater than the 6 gph emergency core cooling system leakage allowed by the System Integrity Program and greater than the 12 gph leakage discussed in Chapter 14 of the USAR for calculation of control room habitability doses and offsite exposure. The licensee entered a seven-day administrative Limiting Condition for Operation per the System Integrity Program. The shift manager declared the pump operable but degraded, in accordance with Generic Letter 91-18, on the basis that the mechanical seal stopped leaking after the pump was electrically started and stopped in short succession (i.e., “bumping”).

The inspectors noted that the operability evaluation did not address whether there was a potential for a catastrophic failure mechanism of the seal. The inspectors also noted that the evaluation did not address the potential radiological consequences of the RHR system barrier leaking reactor coolant outside containment in excess of the limits prescribed by the System Integrity Program and the USAR. The licensee subsequently performed a prompt review to confirm that no immediate catastrophic failure mechanism for the RHR seal existed. The licensee also performed a prompt review of the potential impact of the estimated leakage on the control room habitability doses, as well as the offsite doses. The licensee’s evaluation demonstrated that no exposure limits were likely to be exceeded due to the leakage.

The inspectors interviewed maintenance, engineering and operations personnel. During those interviews, the inspectors determined that leakage from the RHR pump seals on both trains had occurred numerous times in the past following the shutdown of the pumps.

The inspectors reviewed items in the corrective action program and historical work orders that documented the previous mechanical seal leakage, which has occurred on both trains of RHR since at least 1987. The inspectors determined that the licensee's routine practice to address the issue was to rotate the pump shaft, either electrically or manually, such that the leakage stopped. These actions, which were taken by the control room operators on June 16, were prescribed in Procedure A-MDS-30, "Miscellaneous Drains and Sumps (MDS) Abnormal Operation." Step 4.8, "RHR Pump Pit Sump," Step 2.a., stated, "IF (sic) RHR pump was not running, seal leakage may be stopped by rotating shaft by hand or bumping motor."

The inspectors noted that after leakage had occurred on the 'A' RHR pump seal in April 2000, the licensee completed an apparent cause evaluation in January 2001, which stated, "the last time the seal was replaced was 1993 so the seal was due for replacement." The conclusion of the apparent cause evaluation was, "(w)e should continue to monitor pump starts and stops for leakage performance and schedule maintenance which may include checking motor end play and replacing the seal." In addition, the corrective action completed in February 2001 was to review the past RHR pump seal leakage and determine system and pump requirements for a mechanical seal. The licensee concluded that the type of seal used was correct for the application. The corrective action also noted that internal operating experience demonstrated that the seals on the RHR pump historically lasted from four to seven years prior to experiencing leakage upon stopping of the pump. However, the adequacy of the pump seal replacement frequency was not evaluated.

The licensee took actions to immediately stop the RHR pump leakage and plans to replace the RHR pump seal during the next refueling outage.

Analysis: The inspectors determined that the licensee's failure to take effective corrective actions to address the RHR pump seal leakage was a licensee performance deficiency warranting a significance evaluation. This self-revealed finding was greater than minor because the finding affected the barrier integrity cornerstone attribute for reactor coolant system equipment and barrier performance, and the objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

The inspectors determined that the finding could not be evaluated using the Significance Determination Process (SDP) in accordance with NRC IMC 0609, "Significance Determination Process." Although the inspectors determined that the RCS barrier was affected, the Phase 2 worksheets were not applicable because this issue did not affect the mitigation capability of the RHR system. The finding also did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator or affect the containment integrity. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green).

The inspectors also determined that the finding affected the cross-cutting area of Problem Identification and Resolution, because of the failure to take effective corrective actions to address the RHR pump seal leakage.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI," Corrective Action" requires that measures be established to assure that conditions adverse quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the RHR pump seals on both trains have historically been found to be leaking following the stopping of the pump, and has continued to occur on numerous occasions since 1987, most recently on RHR Pump 'B' on June 16, 2004. The licensee's corrective actions to date have failed to assure this condition had been corrected. Therefore, the inspectors determined this finding was a violation of 10 CFR Part 50, Appendix B, Criterion XVI. Because this violation was of very low safety significance (Green) and was documented in the licensee's corrective action program as Condition Reports CAP021589 and CAP021744, this finding is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000305/2004004-01)

.2 Turbine-Driven Auxiliary Feedwater High Bearing Oil Particulate

a. Inspection Scope

The inspectors reviewed the operability evaluation associated with the high bearing oil particulate discovered after the turbine-driven auxiliary feedwater pump turbine bearing oil reservoirs were sampled.

The inspectors reviewed design basis information, the USAR, TS requirements, and licensee procedures to verify the technical adequacy of the operability evaluation. In addition, the inspectors verified that compensatory measures were implemented as required. The inspectors verified that system operability was properly justified and that the system remained available, such that no unrecognized increase in risk occurred. This activity constituted one inspection procedure sample. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

Introduction: The inspectors identified an Unresolved Item (URI) associated with high bearing oil particulate discovered on the turbine-driven auxiliary feedwater pump turbine. The URI will remain open, pending additional licensee evaluation and inspector review of the root cause of the high bearing oil particulate and associated upper journal bearing degradation discovered by the licensee.

Discussion: On June 10, 2004, during a routine 18-month oil change, the licensee took oil samples on the inboard and outboard bearings of the turbine for analysis. The analysis results, which were completed on June 11, indicated the presence of visible metallic particles, and the licensee declared the turbine-driven auxiliary feedwater pump inoperable. The oil samples were sent for analysis to an outside laboratory on June 11. The initial qualitative results identified "high concentrations of steel, severe cutting wear particles, and small rubbing wear particles." On June 12, the licensee removed the inboard and outboard bearing covers and inspected the turbine bearings. The outboard upper journal bearing was slightly scored and some babbitt was displaced. The inboard journal bearings and outboard lower journal bearing were found to have some very light scoring.

Visual inspections identified that the bearing housing surfaces were coated with a silver-colored coating, which was later identified as an aluminum phenolic coating from the original manufacturing. The inspections revealed that areas of this coating were missing, and that small particles of the coating were in the bottom of the bearing housing. The licensee replaced the journal bearings with new bearings, cleaned the bearing housings to remove any additional loose coating, flushed the bearing housing with oil and then filled the turbine with new oil. A post maintenance test was performed and the turbine-driven auxiliary feedwater pump operated satisfactorily. Some potential causes of the bearing degradation were initially identified by the licensee to be the flaking coating inside the bearing housing or the reuse of the upper journal bearing when the licensee last completed a maintenance overhaul of the turbine in 1997. At the end of the inspection period the licensee continued to perform the root cause evaluation.

The inspectors noted that, in October 2001, the oil samples taken from these bearings had similar unsatisfactory analysis results. However, at that time, there did not appear to be a condition report initiated, nor were there any additional actions to correct or identify the cause. The inspectors also noted that the Electric Power Research Institute technical manual for Terry turbine maintenance for auxiliary feedwater applications suggested that the coatings inside the bearing housings be inspected for degradation on the routine 18-month maintenance overhaul. The inspectors also noted the manual provided acceptance criteria for oil sample results and discussed a routine oil sample frequency of 3 months. Finally, the inspectors noted that the degraded upper journal bearing was not appropriately quarantined following removal, because the as-found condition had been disturbed (i.e., the bearing had been wiped clean of residual oil and debris).

Pending the inspectors' review of the licensee's final root cause analysis, this issue will be treated as a URI (URI 050-00305/2004004-02).

.3 Additional Operability Evaluations Reviewed

a. Inspection Scope

The inspectors reviewed the following operability evaluations, completing two inspection procedure samples:

- OPR0064, Sediment Suspected in Service Water Supply to Safety Injection Pump 1B Stuffing Box; and
- OPR0067, Measured Full Power Delta Temperature Different from Predicted.

The inspectors reviewed design basis information, the USAR, TS requirements, and licensee procedures to verify the technical adequacy of the operability evaluations. In addition, the inspectors verified that compensatory measures were implemented, as required. The inspectors verified that system operability was properly justified and that the systems remained available, such that no unrecognized increase in risk occurred. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed previously identified operator workarounds, equipment deficiency logs, and control room deficiencies to verify that the cumulative effects did not create significant adverse consequences regarding the reliability, availability and operation of accident mitigating systems, completing one inspection procedure sample. The inspectors also assessed these cumulative effects on the ability to implement abnormal and emergency response procedures in a correct and timely manner.

The inspectors reviewed the planned actions to address operator workarounds to verify that the priorities to resolve the deficiencies were appropriate when considering the potential impact on plant risk and safety. In addition, the inspectors reviewed emergent risk significant operator workarounds to determine whether the functional capability of a system or human reliability of an initiating event was affected. Finally, the inspectors reviewed condition reports regarding operator workarounds to verify that the corrective actions were prioritized, appropriate, and commensurate with the safety significance of the issue, completing one inspection procedure sample. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post-maintenance testing activities for the following equipment associated with scheduled preventive or corrective maintenance and/or emergent work activities, completing five inspection procedure samples:

- Battery Room Fan Coil Unit 1B ;
- Emergency Diesel Generator ‘A’ following a design modification;
- Auxiliary Feedwater Pump Flow Control Valve AFW-2B following a design modification;
- Plant Fire Dampers in Various Fire Zones; and
- ‘B’ Emergency Diesel Generator Carbon Dioxide System.

The inspectors verified that the testing was adequate for the scope of the maintenance work performed. The inspectors reviewed the acceptance criteria of the tests to ensure that the criteria were clear and that testing demonstrated operational readiness consistent with the design and licensing basis documents. Documents reviewed during this inspection are listed in the Attachment.

The inspectors attended pre-job briefings to verify that the impact of the tests were appropriately characterized. The inspectors also observed the performance of tests to verify that the procedures were followed and that all testing prerequisites were satisfied. Following the completion of each test, the inspectors walked down the affected equipment to verify removal of the test equipment and to ensure that the equipment could perform the intended safety function following the test. The inspectors also reviewed the completed test data to ensure the test acceptance criteria were met for the post maintenance testing.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed and reviewed the surveillance testing results for the following surveillances, completing five inspection procedure samples:

- SP-48-003E and SP-47-316A, Monthly Red Channel Nuclear Power Range Channel 1, N-41, and Instrument Channel Tests;
- SP-55-155A, Engineered Safeguards Train A Logic Channel Test;
- SP-31-168A, Train ‘A’ Component Cooling Water Pump And Valve Test - Inservice Testing;
- SP-42-312B, Diesel Generator ‘B’ Availability Test; and
- SP-31-168B, Train ‘B’ Component Cooling Water Pump And Valve Test - Inservice Testing.

The inspectors verified that the equipment could perform the intended safety function and that the surveillance tests satisfied the TS requirements and the licensee’s procedures. The inspectors reviewed the surveillance tests to verify the tests were adequate to demonstrate operational readiness consistent with the design and licensing basis documents, and that the testing acceptance criteria were well documented and appropriate to the circumstances. Documents reviewed during this inspection are listed in the Attachment.

The inspectors observed portions of the tests to verify the following attributes: performance of the tests in accordance with prescribed procedures; completion of test procedure prerequisites; and verification that the test data was complete, appropriately verified, and met the acceptance criteria of the test. Following the completion of the tests, when applicable, the inspectors walked down the affected equipment to verify test equipment removal and to confirm the equipment tested was in an operable condition.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

The inspectors sampled the licensee's submittals for the PIs listed below, which completed three inspection procedure samples:

- Unplanned SCRAMS per 7,000 Critical Hours;
- SCRAMS with Loss of Normal Heat Removal; and
- Safety System Unavailability- Residual Heat Removal System.

The inspectors used performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2, to verify the accuracy of the PI data. The inspectors reviewed corrective action documents, monthly operating reports, completed surveillance procedures, control room logs, and licensee event reports to independently verify the data that the licensee had collected and reported from January 2003 through March 2004. The inspectors also independently performed calculations for system unavailability when applicable. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Daily Review of Corrective Action Program Documents

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 issues were entered into the licensee's corrective action program at an appropriate threshold; that adequate attention was given to timely corrective actions; and that adverse trends were identified and addressed. The inspectors also reviewed all condition reports written by licensee personnel during the inspection quarter. Minor issues entered into the licensee's corrective action program as a result of inspectors' observations are included in the list of documents in the Attachment, in the section entitled, "Condition Reports Initiated for NRC-Identified Issues."

b. Findings

No findings of significance were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors reviewed the licensee's corrective action program and associated documents to identify trends that may indicate the existence of a more significant safety issue. The inspectors focused on repetitive equipment issues, but also considered the results of daily inspector screening of corrective action program items discussed in Section 4OA2.1 above, licensee trending efforts, and licensee human performance results.

The inspectors nominally considered the six month period of January 2004 through June 2004, although some examples expanded beyond those dates when the scope of the trend warranted. The review also included documents such as the licensee's internal self assessment program performance indicators, system health reports, quality assurance audit and surveillance reports, self assessment reports, and maintenance rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensees trend reports were reviewed for adequacy.

b. Assessment and Observations

There were no findings of significance identified.

The inspectors evaluated the licensee trending methodology and observed that the licensee had performed a detailed review. The licensee routinely reviewed cause codes, corrective action program 'Hot Buttons', and system health reports to identify potential negative trends in corrective action program data. The inspectors compared the licensee process results with the results of the inspectors' daily screening and did not identify any discrepancies or potential trends in the corrective action program data that the licensee had failed to identify. The significant trends identified as a result of this review affected the following areas: fire protection, work management, configuration control/mispositioning, forebay level, and emergency response organization augmentation. The inspectors verified that these trends were captured in the corrective action program.

.3 Problem Identification and Resolution Annual Inspection Sample

Inadequate Job Preparation Leads to Tagout Problems

Introduction

In previous months, the licensee had identified several issues regarding equipment tagout processing, along with coordination and communication between work groups. The inspectors selected Condition Report CAP018690, "Inadequate Job Preparation Leads to Tagout Problems," and Root Cause Evaluation RCE633 for an annual sample review of the licensee's problem identification and resolution program. This constitutes one annual review inspection sample. Documents reviewed during this inspection are listed in the Attachment.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed Condition Report CAP018690 and Root Cause Evaluation RCE633 to verify that the licensee's identification of the problems were complete, accurate, timely, and that the consideration of the extent of condition review, generic implications, common cause, and previous occurrences was adequate.

(2) Findings

No findings of significance were identified.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed Condition Report CAP018690 and Root Cause Evaluation RCE633. The inspectors considered the licensee's evaluation and disposition of performance issues, evaluation and disposition of operability issues, and application of risk insights for prioritization of issues.

(2) Findings

No findings of significance were identified.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the corrective actions identified in Condition Report CAP018690 and Root Cause Evaluation RCE633 for applicability to the identified deficiencies. The inspectors also reviewed multiple related condition reports to determine if the condition reports addressed generic implications and to verify that corrective actions were appropriately focused to correct the problem.

(2) Issues

The inspectors reviewed multiple condition reports identified through independent searches and referenced in Condition Report CAP018690 and Root Cause Evaluation RCE633 to determine the effectiveness to prevent recurrence. The inspectors noted the initial remedial corrective actions were not fully effective in preventing recurrence. The inspectors noted a number of condition reports identifying problems with respect to planning and tagging errors similar to the identified problems in Root Cause Evaluation RCE633. Below are some examples of continuing tagging problems that the inspectors identified during their review:

- CAP019520, "Problems during restoration of Tagout 03-1620," dated January 13, 2004;
- CAP020316, "Location discrepancy on DG A Annunciator power supply replacement tagout," dated March 5, 2004;
- CAP020504, "Inadequate work package review," dated March 19, 2004;
- CAP020731, "Tagout Error," dated April 6, 2004; and
- CAP020976, "WCC not getting work packages reviewed and returned to shops," dated April 27, 2004.

The inspectors also reviewed CAP020670, in which the licensee also identified a large number of human performance errors in mispositioning and tagging which documented this continuing trend. Additional remedial corrective actions were taken and, at the end of the inspection period, the licensee had reduced the trend of mispositioning and tagging errors. The inspectors concluded that the licensee appropriately scheduled the performance of an effectiveness review for Root Cause Evaluation RCE633 in September 2004, following the completion of the corrective actions to prevent recurrence.

4OA3 Event Followup (71153)

.1 (Closed) URI 05000305/2004003-01: Follow-up on open questions regarding past operability of the safety injection pumps commensurate with the identification of lube oil cooler fouling. The inspectors are closing this URI, which was opened in NRC Special Inspection Report No. 05000305/2004003, following the completion of a review and verification of the licensee's past operability determination. The review and verification of the licensee's final past operability determination and root cause evaluation was performed by the inspectors, in conjunction with a technical matter expert from the Office of Nuclear Reactor Regulation and the Regional Senior Reactor Analyst.

The self-revealed findings identified as a result of this review are documented below, in Sections 4OA3.2 and 4OA3.3 of this report. Licensee Event Report 05000305/2004-001-00, "Blocked Lube Oil Coolers to SI Pumps Force Plant Shutdown," will remain open until receipt and review of the supplemental response for Reportable Occurrence 2004-001 from the licensee.

.2 Failure to Identify and Correct Longstanding Safety Injection Pump Lube Oil Coolers Fouling Issues

Introduction: A Green finding associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was self-revealed on January 15, 2004, when licensee inspection of the 'A' and 'B' safety injection pump lube oil coolers revealed silt and lake grass accumulation at the tube pass inlets. Significant fouling of the safety injection pump lube oil coolers with lake grass had been identified as early as 1992, when the coolers were first opened and inspected. The licensee failed to enter the results of those inspections in the corrective action program when fouling was identified until 2001. When the issue was entered into the corrective action program in 2001, the associated evaluation did not adequately address the issue and corrective actions were not taken to address the issue.

Description: Inspection of the 'A' safety injection pump lube oil cooler during a scheduled quarterly inspection on January 15, 2004, revealed silt and lake grass accumulation at the tube pass inlets. The safety injection pump lube oil coolers were two-pass heat exchangers with twenty 0.375" (outer diameter) tubes per pass. The licensee identified that 17 of 20 tubes in each pass were blocked. The licensee measured the "as-found" flow to be between 3.0 and 3.8 gpm, and after cleaning, flow was measured between 5.95 and 6.05 gpm. The blockage prompted the licensee to investigate the condition of the 'B' safety injection pump lube oil cooler. During a visual inspection, the licensee identified that 17 of 20 tubes in each pass of this cooler were also blocked. The results of a flow test performed with the cooler's end bell removed revealed that there was no flow from 17 of the 20 tubes, as seen from the outlet of the cooler and an "as-found" flow rate similar to the 'A' safety injection pump lube oil cooler was measured. The licensee determined that this condition had potentially rendered both safety injection pump trains inoperable and the discovery raised doubts regarding future operability of the safety injection pumps. After discussing these results with senior plant managers, the licensee declared both safety injection pumps inoperable and initiated a plant shutdown on January 16, 2004, at 1:20 a.m.

The licensee's engineering staff had recently performed a calculation (C11423, Revision 0, Addendum A, dated January 12, 2004) to determine service water flow and temperature requirements for the safety injection pump lube oil coolers. The licensee used the calculation to determine the required service water flow rate based on the number of tubes blocked and the service water temperature. The calculation was contradictory to previous operability criteria (i.e., observed flow through the pump's lube oil sight glass and the absence of temperature alarms) and provided the basis for declaring the safety injection pumps inoperable on January 16. The licensee's engineering staff recognized that a previous calculation from 1997, which documented a 1.5 gpm minimum flow criterion, was not appropriate to base an operability determination on because that flow criterion did not consider service water temperature and the minimum number of open tubes needed to provide an adequate heat transfer surface area.

The inspectors interviewed personnel and reviewed work request history and corrective action program documents to understand the sequence of events leading up to this event. Significant fouling of the safety injection pump lube oil coolers with lake grass was identified as early as 1992 when the coolers were first opened and inspected following implementation of the licensee's NRC Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment” program. The licensee continued to identify the same problem during subsequent cooler inspections on roughly an 18-month frequency.

In October 2001, the licensee inspected both coolers. Approximately 80 percent of the tubes on both passes were found blocked with lake grass and silt on the 'A' and ’B’ safety injection pump lube oil coolers. A potential concern for bypass flow around the service water pump discharge strainers was identified in condition report CAP001096; however, an associated corrective action (CA003111) was closed with no action taken to resolve the issue. The inspectors noted that the comments in that corrective action essentially dismissed the potential strainer bypass concern. In addition, the inspectors noted that an associated condition evaluation (CE000901) did not appropriately evaluate the condition. The evaluation stated that maintenance personnel had found that the cooler fouling issue was a routine situation every outage when the coolers were opened and cleaned. The condition evaluation discussed five possible corrective actions; however, no corrective action was implemented. The condition evaluation was categorized as "broke/fix". In May 2002, the licensee wrote an engineering work request to evaluate a modification to replace the existing coolers with a different design having larger diameter tubes to minimize lake grass fouling. In July 2002, the licensee increased the safety injection pump lube oil cooler inspection frequency to every 9 months. Similar fouling was identified in both coolers during inspections in July 2002, May 2003 and October 2003. Still, no positive action was taken to correct this problem, due in part, to the fact that the licensee’s insufficient operability criteria (i.e., observed flow through the pump’s lube oil sight glass and the absence of temperature alarms) at the time were met.

The inspectors also noted that an assessment of the licensee's GL 89-13 program performed by a vendor in December 2002, stated that the safety injection pump lube oil coolers were a "weak spot" in the licensee's component inspection program. The assessment highlighted the history of fouling, noted a strength in the licensee's decision to increase the inspection frequency from every 18 months to every 9 months, and suggested that a shorter inspection interval was warranted based on inspection results at the 9-month frequency. The assessment, however, also noted that the licensee's practice of verifying the absence of alarms and observing flow through a sight glass would not ensure operability of the coolers under design basis accident conditions. The assessment noted other conditions that should be considered in evaluating the operability of the coolers included: delivered flow with the service water system in accident alignment, service water temperature at its design limit, and the safety injection pump moving fluid at accident temperatures for a prolonged period of time (i.e, for the duration of the post-accident function). The inspectors noted that the assessment did not mention any consideration of the actual amount of tube plugging (i.e., available heat transfer area), which would also affect the heat removal capability of the coolers.

In May 2003, the licensee completed a review of abnormal plant conditions or indications that could not be easily explained. The licensee identified that the fouling of the safety injection pump lube oil coolers was a widely known issue which had not been aggressively pursued, had existed for a long period of time, and had the potential to affect an important piece of safety-related equipment. The inspectors noted that a corrective action to complete an engineering work request to find a solution to the safety injection pump lube oil cooler fouling problem was deferred multiple times and had not been completed at the time of the January 2004 event. The inspectors also noted that the only two corrective actions completed in response to this issue, changing the inspection frequency to every 3 months and performing ultrasonic flow testing, were not effective at preventing the event.

Although the cooler inspection history also existed in the licensee's work request database, the inspectors noted that the results of many of these individual inspections in which significant fouling was identified were not consistently entered into the corrective action program. The licensee had not identified the fouling as a potential significant condition adverse to quality and did not routinely document the results in the corrective action program for evaluation, trending and early identification of problems. In particular, the inspectors noted that there were no condition reports specifically associated with the results of recent safety injection pump lube oil cooler inspections in May 2003 and October 2003, during which the licensee identified tube fouling.

Past Operability Analysis

From February through May 2004, the licensee evaluated the past operability of the safety injection pump lube oil coolers. The inspectors, in conjunction with a technical matter expert from the Office of Nuclear Reactor Regulation and the Regional Senior Reactor Analyst, reviewed the licensee's analysis, and verified the assumptions and calculations made by the licensee in Calculation MPR-2658, "Safety Significance Evaluation for Kewaunee High Head Safety Injection Pump Lube Oil Cooler Degradation," Revision 0. The inspectors verified the following conclusions made by the licensee in this series of calculations during the inspection:

- The debris buildup on the tubesheets degraded service water flow to the coolers. The typical as-found condition during past inspections was the equivalent of approximately three unobstructed tubes through each pass of the cooler. Based on past inspections of the coolers and interviews with auxiliary operators, there was always some service water flow through the coolers. The actual flow conditions and blockage in the lube oil cooler was difficult to quantify; therefore, the licensee's evaluation assumed the bounding case of full blockage and no service water flow.

- The allowable oil temperature for the pump was limited by oil performance at elevated temperatures, the effect of increased temperatures on components in the lube oil system, and the required operating time of the safety injection pumps. Based on information obtained from the bearing, pump and oil vendors, as well as additional evaluations of the pump components, the safety injection pumps would operate reliably and be capable of performing all required safety functions for at least 96 hours for bulk lube oil temperatures up to 230 degrees Fahrenheit (°F).

- The two potentially limiting events for the evaluation were the small break loss of coolant accident (LOCA) and the 10 CFR Part 50, Appendix R fire scenario. The small break LOCA resulted in higher lube oil temperatures, but the event duration and required operating time were shorter than the Appendix R scenario. The Appendix R scenario resulted in lower, but still elevated, lube oil temperatures of a longer duration.

- The required operating time for the safety injection pumps for a small break LOCA was approximately 7 hours of continuous service. During the Appendix R scenario the safety injection pumps would be cycled on and off during the event to provide reactor coolant inventory control. The longest single continuous run cycle was 90 minutes and the total run time during the event was approximately 22 hours. For conservatism, due to the varying amounts of cooling during the pump idle times, the licensee conservatively assumed that the pump must be run for the entire 80-hour Appendix R event. In addition, the evaluation considered the operating times for both events.

- In the bounding case of a total loss of service water flow through the lube oil cooler, the bulk oil temperature would have remained below 220°F for the small break LOCA and below 211°F for the Appendix R scenario.

- The licensee performed a sensitivity analysis and concluded that with three tubes available in the cooler and a service water flow rate of 3 gpm, the maximum lube oil temperature would have remained less than 179°F, assuming long-term operation at the maximum recorded service water temperature and small break LOCA conditions. The sensitivity analysis also concluded that with one tube available in the cooler and a service water flow rate of 1 gpm, the maximum lube oil temperature would have remained less than 202°F, assuming long-term operation at the maximum recorded service water temperature and small break LOCA conditions.

The licensee initiated numerous corrective actions to address the root and contributing causes identified during the root cause evaluation of this event. Some of those actions included: replacing the old safety injection pump lube oil coolers, with coolers of a new design incorporating a larger tube diameter and higher flow velocities through the cooler; completing an extent of condition review of other service water systems prior to plant restart to ensure no similar immediate issues existed; reviewing the effectiveness of service water treatments for the control of zebra mussels; sharing lessons learned from this event with all plant staff; and performing a prioritization review of all outstanding plant design modifications.

Analysis: The inspectors determined that the failure to promptly identify and correct the repeated fouling of the safety injection lube oil coolers from 1992 through January 2004 was a licensee performance deficiency warranting a significance evaluation. This self-revealed issue was more than minor because, if left uncorrected, the issue could have become a more significant safety concern. In addition, the inspectors concluded that the failure to correct the fouling of the safety injection pump lube oil coolers affected the mitigating systems attributes of equipment performance reliability. Finally, the issue affected the mitigating systems cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences.

As discussed, the inspectors verified the licensee's past operability analysis for the safety injection pumps. The inspectors evaluated the finding using the results of that analysis and IMC 0609, Appendix A, Phase 1 screening, and determined that, based on the past operability analysis performed by the licensee, the finding:

- was not a design or qualification deficiency confirmed not to result in a loss of function per GL 91-18;
- did not represent an actual loss of safety function of a system;
- did not represent an actual loss of a safety function of a single train for greater than TS outage time;
- did not represent an actual loss of a safety function of one or more Non-TS trains of equipment designated as risk significant; and
- did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

Therefore, the finding was determined to be of very low safety significance (Green).

The inspectors determined that the finding affected the cross-cutting area of Problem Identification and Resolution, because of the failure to promptly identify and correct the lube oil cooler fouling.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, and nonconformances be promptly identified and corrected. Contrary to this requirement, the licensee failed to promptly identify and correct issues associated with the fouling of the safety injection pump lube oil coolers, a safety-related component, as evidenced by the lack of condition reports documenting this issue in the corrective action program from 1992 through 2001 and from 2001 through 2003, and the failure to correct the condition when identified in a condition report in October 2001. Therefore, the inspectors determined this finding was a violation of 10 CFR Part 50, Appendix B, Criterion XVI. Because this violation was of very low safety significance (Green) and was documented in the licensee's corrective action program as Condition Report CAP19545, this finding is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000305/2004004-03)

.3 Inadequate Procedures Associated with Generic Letter 91-18 Inspections of the Safety Injection Pump Lube Oil Coolers

Introduction: A Green finding associated with a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when the licensee discovered fouling of the safety injection pump lube oil coolers in January 2004. The licensee determined that evidence of the fouling had been present since the first inspection of the safety injection lube oil coolers in 1992, conducted in response to GL 89-13. However, no acceptance criteria were contained in the licensee's procedures developed to implement the commitments of GL 89-13 to ensure that this important activity had been satisfactorily accomplished.

Description: As discussed in Section 4OA3.2, the safety injection lube oil coolers were identified with significant fouling on January 15, 2004. The inspectors interviewed personnel and reviewed work request history and corrective action program documents to understand the sequence of events leading up to this event, and to understand the inspections which were performed as a result of licensee commitments made in response to GL 89-13.

The licensee identified significant fouling of the safety injection pump lube oil coolers with lake grass as early as 1992, when the coolers were first opened and inspected following implementation of the licensee's GL 89-13 program. The licensee continued to identify the same problem during subsequent lube oil cooler inspections on roughly an 18-month frequency. In July 2002, the licensee increased the inspection frequency to every 9 months, and to every three months in October 2003.

In reviewing the history of the documentation of the lube oil cooler fouling, the inspectors reviewed the work instructions and implementing Procedure PMP 33-01, "Safety Injection (QA-1) Pump Maintenance." The licensee used this procedure to implement the inspection and cleaning of the safety injection lube oil pump coolers, in accordance with its GL 89-13 commitments. The inspectors, as well as the licensee, concluded that the procedure guidance was inadequate, in that no specific acceptance criteria were prescribed to ensure adequate implementation of the activity.

As discussed in Section 4OA2.2, when the fouling was identified during past inspections and cleaning, the licensee relied upon verification that flow through an open flapper in a sight glass and verification of no temperature alarms in the control room to assure operability. Flow through the open flapper was rationalized as adequate due to a 1997 calculation, which established a required minimum flow to the coolers of 1.5 gpm. However, this was an incorrect application of the results because the calculation was for potential service water piping blockage to the coolers which did not account for the full range of expected service water temperatures and assumed no flow blockage in the cooler (all tubes open).

The licensee initiated several corrective actions to address this issue, some of which included: establishing appropriate acceptance criteria for the safety injection lube oil coolers; developing a recovery plan for the licensee's GL 89-13 program and categorizing the program health in a red status; designating a single program owner to the GL 89-13 program; and reviewing other procedures utilized to implement the licensee's GL 89-13 program to verify specific acceptance criteria were contained in the procedures.

Analysis: The inspectors determined that the failure to ensure that appropriate acceptance criteria were established in the procedures which implemented GL 89-13 commitments for inspection and cleaning of the safety injection lube oil coolers was a licensee performance deficiency warranting a significance evaluation. This self-revealed issue was greater than minor because if left uncorrected, the issue could have become a more significant safety concern. In addition, the inspectors concluded that the failure to correct the fouling of the safety injection pump lube oil coolers affected the mitigating systems attribute of equipment performance reliability. Finally, the issue affected the mitigating systems cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences.

As discussed in the Section 4OA3.2 of this report, the inspectors verified the licensee's past operability analysis for the safety injection pumps. The inspectors evaluated the finding using the results of that analysis and IMC 0609, Appendix A, Phase 1 screening, and determined that based on the past operability analysis performed by the licensee, the finding:

- was not a design or qualification deficiency confirmed not to result in a loss of function per GL 91-18;
- did not represent an actual loss of safety function of a system;
- did not represent an actual loss of a safety function of a single train for greater than TS outage time;
- did not represent an actual loss of a safety function of one or more Non-TS trains of equipment designated as risk significant; and
- did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

Therefore, the finding was determined to be of very low safety significance (Green).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions or procedures, of a type appropriate to the circumstances and shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to this requirement, the licensee failed to establish acceptance criteria in Procedure PMP 33-01, utilized to inspect and clean the safety injection lube oil coolers, in accordance with commitments the licensee made for implementation of GL 89-13. Therefore, the inspectors determined this finding was a violation of 10 CFR Part 50, Appendix B, Criterion V. Because this violation was of very low safety significance (Green) and was documented in the licensee's corrective action program as Condition Reports CAP19586, CAP19999, and CAP017771, this finding is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000305/2004004-04)

4OA4 Cross Cutting Aspects of Findings

.1 A finding described in Section 1R15.1 of this report had, as the primary cause, a problem identification and resolution deficiency, in that, the licensee failed to take effective corrective actions to address the historic RHR pump seal leakage issues dating back to the late 1980's.

.2 A finding described in Section 4OA3.2 of this report had, as the primary cause, a problem identification and resolution deficiency, in that, the licensee failed to identify and correct the repeat fouling of the safety injection lube oil coolers which had reoccurred since at least 1992.

4OA5 Other (TI 2515/156)

.1 Temporary Instruction (TI) 2515/156, "Offsite Power System Operational Readiness"

a. Scope

The inspectors collected data from licensee maintenance records, event reports, corrective action documents, and procedures, as required by the TI. In addition, the inspectors interviewed station engineering, maintenance, and operations staff, as well as the appropriate Transmission and Distribution personnel, as required by the TI. The data was gathered to assess the operational readiness of the offsite power systems in accordance with NRC requirements such as Appendix A to 10 CFR Part 50, General Design Criterion (GDC) 17; Criterion XVI of Appendix B to 10 CFR Part 50, Plant TSs for offsite power systems; 10 CFR 50.63; 10 CFR 50.65 (a)(4), and licensee procedures. Documents reviewed for this TI are listed in the Attachment.

b. Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis.

4OA6 Meetings

.1 Exit Meeting

On July 1, 2004, the resident inspectors presented the inspection results to Mr. K. Hoops and other members of licensee management, who acknowledged the findings presented. The licensee did not identify any materials examined during the inspection as proprietary in nature.

4OA7 Licensee-Identified Violations

The following violation of very low significance was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as a Non-Cited Violation.

Cornerstone: **Initiating Events**

Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Drawings and Procedures," requires, in part, that activities affecting quality be accomplished in accordance with procedures. On two occasions within 1 week, during routine at-power reactor flux mapping performed in accordance with Procedure RE-1, human performance errors resulted in the failure to properly implement the procedure, an activity affecting quality.

The licensee identified these failures, which were documented in Condition Reports CAP020598, "Missed Step in Performance of RE-1, Flux Mapping at Power," and CAP020614, "Flux Map Procedure Step Not Followed." No adverse equipment consequences resulted from the human performance failures and corrective actions were initiated by the licensee which included institution of peer checking and place keeping for this activity.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Nuclear Management Company, LLC

T. Coutu, Site Vice President
K. Hoops, Site Director
K. Davison, Plant Manager
L. Armstrong, Engineering Director
S. Baker, Manager, Radiation Protection
L. Gerner, Acting Regulatory Affairs Manager
E. Gilson, Security Manager
W. Godes, Operations Training General Supervisor
G. Harrington, Licensing
W. Hunt, Training Manager
D. Lohman, Operations Manager
B. Presl, NMC Security Consultant
S. Putman, Manager, Maintenance
R. Repshas, Manager, Site Services
J. Riste, Licensing Supervisor
J. Stafford, Superintendent, Operations

NRC Personnel

C. F. Lyon, Project Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000305/2004004-01	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the failure to correct historical residual heat removal pump mechanical seal leakage (Section 1R15.1)
05000305/2004004-02	URI	Review of Final Analysis Concerning High Oil Particulate discovered in the Turbine Driven Auxiliary Feedwater Pump Turbine (Section 1R15.2)
05000305/2004004-03	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the Failure to Identify and Correct Issues Associated with Historical Safety Injection Lube Oil Cooler Fouling (Section 4OA3.2)
05000305/2004004-04	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the Failure to Have Procedures Appropriate to the Circumstances, Including Appropriate Acceptance Criteria for Implementation of the Generic Letter 89-13 Program with Respect to the Safety Injection Lube Oil Coolers (Section 4OA3.3)

Closed

05000305/2004003-01	URI	Follow-up on Open Questions Regarding past Operability of the Safety Injection Pumps Commensurate with the Identification of Lube Oil Cooler Fouling (Section 4OA3.1)
05000305/2004004-01	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the failure to correct historical residual heat removal pump mechanical seal leakage (Section 1R15.1)
05000305/2004004-03	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the Failure to Identify and Correct Issues Associated with Historical Safety Injection Lube Oil Cooler Fouling (Section 4OA3.2)

05000305/2004004-04	NCV	Green. Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the Failure to Have Procedures Appropriate to the Circumstances, Including Appropriate Acceptance Criteria for Implementation of the Generic Letter 89-13 Program with Respect to the Safety Injection Lube Oil Coolers (Section 4OA3.3)

Discussed

05000305/2004-001-00	LER	Blocked Lube Oil Coolers to SI Pumps Force Plant Shutdown (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

The following is a list of 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 of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather Protection

KNPP Operating Procedure Number E-0-05; Response to natural events, dated April 6, 2004
KNPP USAR; Appendix B, Section B.6.3
CAP 021775; Acceptability of Storage Locations for Chlorine Totes and Propane Tanks
Operating Procedure E-0-5; Response to Natural Events

1R04 Equipment Alignment

N-ICS-23-CL; Containment Spray System Prestartup Checklist; Revision AB
KNPP SP-34-099B; Train 'B' RHR Pump and Valve Test-IST
KNPP System Description; Residual Heat Removal System; dated 10/15/02
Flow Diagram Oper. XK-100-1B; Aux. Coolant System
OPERM-213-9; Diesel Generator Startup Air System Drawing; Rev B
OPERM-217; Flow Diagram - Internal Containment Spray System; Revision AM
OPERM-220; Diesel Generator Fuel Oil System Drawing; Rev AF

1R05 Fire Protection

Kewaunee Fire Protection Program Analysis; Revision 5
FP-08-08; Control of Transient Combustible Materials; Revision D
PMP 08-21; FP-Fire Damper Visual Inspection; Revision F
Drawing No. A-543; Turbine Building Mezzanine
Drawing No. A-542; Turbine Building Basement
Drawing No. A-533; Protected Area Plant Layout
Drawing No. A-545; Turbine Building Operating Floor
KNPP Fire Protection Program Analysis; Fire Zone Summary; Revision 5
PFP-6; B Diesel Generator and DG Day Tank Rooms; Rev. B
PFP-16; Refueling Water Storage Tank and Containment Spray Pump Area; Revision B
PFP-12; Main Transformers A, B and C, Main Auxiliary Transformer, Reserve Auxiliary Transformer, Tertiary Auxiliary Transformer and Turbine Mezzanine
WO-02-013-034-000; Fire Penetration 457 Needs Repair. Located in Auxiliary Building Elev. 586 at Door 264
GMP-208; The Opening and Sealing of Penetration Seals
M-1248; Sections and Details Sealing of Pipe Penetrations for US Gypsum Walls and Floors
Calculation No. 180; Combustible Inventory Worksheet - Fire Zone AX-223A; Revision 0

Drawing No. 237127A-A362; Architectural Drawing - Sections and Details Appendix 'R' Fire Walls; dated 2/3/85

1R11 Licensed Operator Requalifications

LRC-04-SE301; Steam Generator Tube Leak-Rupture and Cooldown Using Steam Dumps; dated 5/22/2003
UFSAR Chapter 14; Section 14.2.4, Steam Generator Tube Rupture; Rev. 18

1R12 Maintenance Implementation

Radiation Monitoring System (System 45)

MRE001573; R23 failure during SP 45-049.23; dated 8/26/2002
ACE002159; Radiation Monitor R-7, MR Function 45-01 (a)(1) evaluation; dated 2/17/2003
ACE002333; R-22 MR Function 45-01 (a)(1) evaluation; dated 6/12/2003
ACE002377; R-11, R-20, and System 45 MR Function 45-01 (a)(1) evaluation, dated 8/1/2003
CAP014683; Radiation Monitor R-7, MR Function 45-01(a)(1) evaluation; dated 2/10/2003
MRE001801; Radiation Monitor R-20 spiking; dated 4/3/2003
MRE001804; R-13 Failure during AP-14-117; dated 4/4/2003
CAP015928; R-22 failed at 0456 on 4/20/03; dated 4/20/2003
MRE001857; Perform a Maintenance Rule Evaluation per Cap 15928; dated 4/21/2003
CAP016065; Containment SPING; dated 4/24/2003
CE012617; Containment SPING; dated 4/25/2003
CAP016285; R-15 Detector Link Failure; dated 5/5/2003
MRE001941; R-15 Detector Link Failure; dated 5/6/2003
CAP016405; R-11 paper not moving; dated 5/12/2003
MRE001963; R-11 paper not moving; dated 5/13/2003
MRE002033; R-23 out of service; dated 6/23/2003
MRE002060; R-20 calibration out of tolerance; dated 7/16/2003
MRE002064; Identification of rework on R-11 Paper Drive Motor; dated 7/21/2003
MRE002066; TLA Alarm on R-17; dated 7/22/2003
CAP017371; R-11/12 failure; dated 7/24/2003
ACE002370; R-11/12 failure; dated 7/26/2003
MRE002072; R-11/12 failure; dated 7/25/2003
MRE002073; Control Bank Low Limit Alarms received during troubleshooting of R-11; dated 7/28/2003
CAP018840; Common Cause Radiation Monitors High Unavailability; dated 11/7/2003
CAP019925; Maintenance Rule Assessment Recommendations; dated 2/11/2004
CA015500; Maintenance Rule Assessment Recommendations Radiation monitoring; dated 3/9/2004
MRE001750; Radiation Monitor R-7; MR Function 45-01 (a)(1) evaluation; dated 2/12/2003

MRE001813; R-16 out of service; dated 4/8/2003
MRE002133; R-19 Flow meters are Out of Service; dated 9/9/2003
CAP020721; Maintenance Rule Performance Criteria Questioned; dated 4/6/2004
Maintenance Rule System Basis for Radiation Monitors ; Revision 3
Listing of Corrective Actions for Radiation Monitors System 45 from 5/2002 to 4/2004; dated 4/6/2004

4160 Volt Electrical Supply and Distribution (System 39)

System 39 Closed Work Orders (April 2002 to April 2004); dated 4/16/2004
Work Order 02-013019-000; Armature air gap for the trip coil on breaker 1-301 found our of tolerance; dated 8/22/2002
Work Order 02-014055-000; Buffer clearance found out of tolerance for Aux Reserve Transformer breaker; dated 8/27/2002
Work Order 02-014379-000; Changing motor mounting screw(s) on spare 4160 vacuum breaker; dated 9/19/2002
Work Order 02-016529-000; Loose bolts on the upper flex joint to bus bar connection; dated 10/21/2002
Work Order 02-016566-000; The interlock plunger would not clear the permissive device on the cubicle floor guide rail for breaker 1-606; dated 10/26/2002
Work Order 02-017672-000; Breaker 1-403 failed to discharge when the breaker positioning handle was moved to the racking position; dated 12/09/2002
Work Order 03-002640-000; 1-501 Breaker limit switch cutout failed to open to de-energize the charging motor; dated 2/28/2003
Work Order 03-002725-000; A wire terminal is loose on the normally open contract of PS1 limit switch; dated 3/11/2003
Work Order 03-004083-000; Found cracked bus bar insulation loose bolts on the outdoor section of the MAT bus duct; dated 4/14/2003
Work Order 03-005320-000; Breaker 1-407 closing spring charging motor would not run when energized; dated 4/30/2003
Work Order 03-005341-000; Electrician was unable to charge the closing spring with either the hand pump or the charging motor for breaker 1-304; dated 5/05/2003
Work Order 03-011328-000; 1-407 breaker found to have a hydraulic leak on the charging pump; dated 10/20/2003
SP-39-021A; BUS 1-1 4Kv Voltage and Frequency Test and Calibration; dated 11/26/2002
Listing of CAPs for System 39 from April 2002 to April 2004
MRE000608; Relay 81C/B1 Timing Drift; dated 4/6/2002
CAP003891; Bus 1-1 and 1-2 under frequency relays; dated 4/15/2002
MRE001549; Relay 2C1/B1 out of acceptance criteria band; dated 8/1/2002
MRE001631; Breaker 1-609 high primary circuit resistance; dated 10/24/2002
CAP013364; A review of calc #C-039-001; Rev. 1 identified several issues; dated 10/18/2002
CAP014373; Main Transformer Alarm; dated 1/17/2003
MRE001719; Main Transformer Alarm; dated 1/21/2003
CAP014557; SP-39-021 Bus 1-2 UV/UF Relay could not be completed as written; dated 2/3/2003

MRE001737; SP-39-021 Bus 1-2 UV/UF Relay could not be completed as written; dated 2/5/2003
CAP015096; Bus 1-2 Relay 81CX/B2 has faulty contacts for alarm functions; dated 3/6/2003
MRE001776; Bus 1-2 Relay 81CX/B2 has faulty contacts for alarm functions; dated 3/10/2003
CAP015510; Loss of C Phase of 345 kv line R-304, KNPP to North Appleton- near miss; dated 4/4/2003
CE012257; Loss of C Phase of 345 kv line R-304, KNPP to North Appleton- near miss; dated 4/5/2003
CAP015999; Bus 5, 4160V Switchgear Maintenance; dated 4/22/2003
CAP017380; Protective relay 50/51C/1-606BKR our of spec at alarm point; dated 7/24/2003
MRE002074; Protective relay 50/51C/1-606BKR our of spec at alarm point; dated 7/28/2003
Westinghouse Electric Corp. WCAP-11547; Wisconsin Public Service Corporation Kewaunee Nuclear Power Plant Final “Under frequency Event Transient Analysis Report;” dated 8/17/1987
Maintenance Rule System Basis for 4160 Volt Electrical Supply and Distribution; Revision 4

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

Safety Monitor Risk Assessments; Control Room Logs and Work Schedule for April 5 through 9, 2004
Safety Monitor Risk Assessments; Control Room Logs and Work Schedule for April 26 through 30, 2004
Safety Monitor Risk Assessments; Control Room Logs and Work Schedule for June 1 through 4, 2004
Safety Monitor Risk Assessments; Control Room Logs and Work Schedule for June 14 through 18, 2004
GNP 08.02.15; General Nuclear Procedure - Maintenance Activity Risk Assessment/ Management Process; Revision A
CAP020811; Risk Higher than Predicted
CAP020705; Poor Communication/ Accountability Leads to unnecessary LCO Time/Work Delays
CAP021033; Addition of Substation Work Takes Risk Profile into Orange Level
CAP021049; STA Unaware How to Perform PRA Safety Monitor Risk Look Ahead

1R15 Operability Evaluations

OBD00085; RHR Pump B Seal Leakage
KNPP SP-34-099B; Train ‘B’ RHR Pump and Valve Test-IST
CAP 011440; RHR Pump A Experienced Excessive Seal Leakage
MRE 001478; Maintenance Rule Evaluation-A RHR Pump Seal
ACE 001780; Apparent Cause Evaluation-RHR Pump Seal

CA 007412; RHR Pump Seal Leakage
Incident Reports 87-68, 89-085, 89-108; RHR Pump Seal Leakage
CAP 021589; RHR Pump 'B' Seal Leakage
CAP 021601; RHR Pump Seal Leakage Impact on SIP
CAP 021744; RHR Pump Seal Evaluation
KNPP USAR Chapter 14; Section 14.3.5
KNPP USAR Chapter 6; Section 6.2.5; Table 6.2-11
OPR000070; Turbine Driven auxiliary Feedwater Pump Turbine Oil Samples Contained Contaminants
CAP 021627; RXCP 'A' #1 Seal Leakoff Unusual Indications
CAP 020776; Trend of RCP 'A' Seal Leakoff
ACE 002638; Trend of RCP 'A' Seal Leakoff
CAP 020814; Control Room Alarm 470131, RCP 'A' Seal Leakoff Flow High/Low
CAP 020804; Control Room Annunciator 470131, RCP 'A' Seal Leakoff Flow High/Low Received
CAP 020832; Control Room Alarm 470131, RCP 'A' Seal Leakoff Flow High/Low
CAP 020833; Control Room Alarm 470131, RCP 'A' Seal Leakoff Flow High/Low
CAP 020948; Control Room Alarm 470131, RXCP 'A' Seal Leakoff Flow High/Low Received
CAP 020845; Planning for Possible Forced Shutdown for RXCP Seal Leakage
CAP 020952; Control Room Alarm 470131, RXCP 'A' Seal Leakoff Flow High/Low Received
CAP 020950; High Leakoff Flow Alarm for RXCP 'A'
CAP 020917; RCP Seal Injection Filters - DCR
EWR 016023; Evaluate Potential Reduction of VCT Temperature to Reduce RCP 'A' Seal Leakoff
WO 016088; Trend of RCP 'A' Seal Leakoff
ACE 002663; Abnormal RXCP Seal Leakoff Indication during SP-55-167-5
CAP 021234; Abnormal RXCP Seal Leakoff Indication during SP-55-167-5
OTH 016290; Trend of RCP 'A' Seal Leakoff
CAP 021599; NRC Resident Inspector Concerns on the TDAFW Pump Operability
CAP 021598; Operability Definition Application in Question
OPR 000070; Operability Definition Application in Question
Generic Letter 91-18; Revision 1; Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions
GNP 11-08-03; Revision C; Operability Determination
FP-OP-OL-01; Revision 0; Operability Determination
COLR Cycle 26; Technical Requirements Manual; Rev. 3
XK-100-549; Instrument Block Diagram-Temperature Differential-T_{AVE}; Rev. RW
OPR0067; Full Power Delta T Different than Predicted
System 47; KNPP System Description-Reactor Protection & Reactor Coolant Temperature Instrument; Rev. 1

1R16 Operator Workarounds

NAD-12.07; Operator Workaround; dated 9/19/2002
Operator Workaround 03-06; Caustic Dilution Heat Exchanger warmup relay occasionally locks up; dated 11/15/03
Operator Workaround 01-16; Response to Generic Letter 96-06; dated 8/14/01
Operator Workaround 01-15; SAP refrigeration unit is ineffective; dated 8/14/01
Operator Workaround 02-11; TSC annunciator panel trouble is locked in due to low humanity alarm in TSC computer room HVAC; dated 11/12/02; closed 12/19/02
Operator Workaround 03-01; Turbine defoaming tank level alarm in but tank level is normal; dated 5/22/03; closed 6/16/03
Operator Workaround 03-02; Generator air side seal oil temperature not being controlled within the Hi/Low alarm limit; dated 5/21/03; closed 7/17/03
Operator Workaround 03-03; Service water Pump A strainer is in continuous backwash, requires manual operation; dated 6/26/03; closed 6/30/03
Operator Workaround 03-04; Leaking relief valve on Excess Letdown heat exchanger requires more manual effort to maintain proper surge tank level; dated 9/7/03; closed 9/7/03
Operator Workaround 03-05; Failure of auto backwash for Service Water Pump; dated 9/18/03; closed 9/19/03
Operator Workaround 03-07; Diesel generator A not be shutdown until electricians can inspect a suspect relay; dated 11/20/03; closed 11/24/03
Operator Workaround 02-01; Component cooling pump overheating with two pumps operating; dated 1/11/02; closed 11/18/03
Operator Workaround 04-01; E H system temperature is controlled using bypass valves; dated 1/12/04; closed 2/2/04
Temporary Change Tracking Form 03-023; Instillation of alternate level for defoaming tank level alarm; dated 5/28/03
Temporary Change Tracking Form 02-18; Removal of Low humidity in TSC alarm to the TAC annunciator panel trouble alarm; dated 12/06/04

1R19 Post-Maintenance Testing

CAP 021446; Questioning Attitude and NRC Questions on PMP 08-30
PMP 08-30; FP-CO2 System Inspection and Dry Test (QA-1)
PMP 08-21; FP-Fire Damper Visual Inspection; Revision F
WO-04-001470-000; Work Order - Take Measurement for the ‘1B’ Battery Room Fan Coil Unit Airside Flow and Service Water Flow
Tagout for WO-04-001470-000; dated May 5, 2004
PMP 16-09; TAV- Battery Room Fan Coil unit Performance Monitoring
DCR 3441; Replace AFW-2A(B) Stem Packing and I/P Transducers
GNP 08.02.11; Online Maintenance Planning and Scheduling
DCR 3507; Diesel Generator Surge Suppression
WO 03-9847; Work Instruction-Surge Suppression of Relay ESR/D1A
RCE000607; Diesel Generator B Failure to Start; Revision 1
SP-42-312A; Diesel Generator A Availability Test

CAP021415; NRC Questioned Timeliness and Extent of Condition Evaluation for Agastat Relays
CAP021374; Acceptance Criteria for D-1A Surge Suppressor May Not Have Been Met
OTH011371; Reanalyze Series E7000 Agastat Relay Contact Circuits for Failure

1R22 Surveillance Testing

SP-48-003E; Nuclear Power Range Channel 1 (Red) N-41 Monthly Test; Revision L
SP-47-316A; Channel 1 (Red) Instrument Channel Test; Revision R
SP-55-155A; Engineered Safeguards Train A Logic Channel Test; Revision P
SP-42-312B; Diesel Generator 'B' Availability Test; Revision S
SP-31-168A; Train 'A' Component Cooling Pump and Valve Test - IST; Revision D
SP-55-177; Inservice Testing of Pumps Vibration Measurements; Revision AA
OPERXK-100-19; Flow Diagram Component cooling System; Revision AJ
N-CC-31-CL; Component Cooling System Prestartup Checklist; Revision Z
GMP-131; Operational Use for SKF Microlog Analyzers; Revision F
SP-31-168B; Train 'B' Component Cooling Pump and Valve Test - IST; Revision C
Temporary Change Form; Operational Use for SKF Microlog Analyzers; dated July 18, 2002
Preventive WO 04-788; Vibration Monitoring; dated May 19, 2004
Surveillance WO 04-533; Vibration Monitoring; dated May 19, 2004
SP 55-177; Inservice Testing of Pumps Vibration Measurements; Revision AA
GNP 03-24-01; Revision D; Job Briefs Implementation
CAP021288; CCW Pump Discharge Pressure Indicators Extent of Condition
ACE002669; CCW Pump Discharge Pressure Indicators Extent of Condition
CAP021228; CAP not Written for Degraded Equipment CCW Pump 1B PI 11150
ACE002662; CAP not Written for Degraded Equipment CCW Pump 1B PI 11150
CAP020887; CCW Pump A Performance Anomaly
CAP021045; CC-3B Did Not Audibly Click During Shifting Plant Equipment
CAP019600; Performance of SP-55-155C Identified Logic Discrepancies Between ESF Trains

4OA1 Performance Indicator Verification

KNPP PI Date for 1st Quarter 2003, 2nd Quarter 2003, 3rd Quarter 2003, 4th Quarter 2003
KNPP PI Data for 1st Quarter 2004
Control Room Logs dated 1/16/04 and 4/4/03
N-CRD-49C; Reactor Shutdown; dated 2/27/2003
N-O-04; 35 percent Power to Hot Shutdown Condition; dated 3/21/2004
N-O-01; Plant Startup from Cold Shutdown to Hot Shutdown Conditions; dated 1/20/2004
Temporary Change dated 4-24-2004 to N-O-01; Plant Startup from Cold Shutdown to Hot Shutdown Conditions
N-TB-54; Turbine and Generator Operation; dated 10/28/2003
Licensee Event Report 2001-004; dated 8/2/2001
GNP-03.18.01, Appendix B; pgs 19 & 20; Mitigating System Cornerstone; dated 1/13/2004

4OA2 Identification and Resolution of Problems;

GNP 03.03.01; Tagout Processing; dated 7/24/2003
GNP 08.02.08; Work Order Planning; dated 3/23/2004
CAP "Detailed Description" Word Search for "Tagout" from 1/2004 to 5/2004
GNP 11.08.01; Action Request Process; dated 12/16/2003
CAP018690; Inadequate job preparation leads to tagout problems; dated10/29/2003
RCE000633; Inadequate job preparation leads to tagout problems; dated 12/16/2003
OTH010999; Track the incorporation of a statement into a new procedure that is currently in development; dated 3/28/2003
CA015224; Develop and implement an accountability standard; dated 2/11/2004
CA014719; Determine feasibility of creating work space to include Taggers, Planners, and WWC; dated 12/16/2003
RFT014720; Determine tasks performed by WCC/SRO and Taggers that require training; dated 12/16/2003
PCR014721; Revise GNP 03.03.01 and NAD 03.03; dated 12/16/2003
PCR014722; Revise GNP 08.02.11; dated 12/16/2003
PCR014723; Revise GNP 08.02.01; dated 12/16/2003
RFT014740; Perform review of training needs concerning work planning/work package preps; dated 12/16/2003
OTH015531; Work Control define specific requirements for planners with tagouts; dated 3/11/2004
OTH015530; Work Control conduct briefing to "planners" on expectations; dated 3/11/2004
CA014741; Perform review of expectations; dated 12/16/2003
EFR014742; Inadequate job preparation leads to tagout problems; dated 12/16/2003
CA013708; 2003 Culture Survey leadership deficiency action 1; dated 9/25/2003
CA013709; 2003 Culture Survey leadership deficiency action 2; dated 9/25/2003
CAP019520; Problems during restoration of Tagout 03-1620; dated 1/13/2004
CAP019687; Work order completed without QC review; dated 1/24/2004
CAP019815; Diver-Operations, communication shortfall; dated 2/2/2004
CAP020316; Location discrepancy on DG A Annunciator power supply replacement tagout; dated 3/5/2004
ACE002601; Location discrepancy on DG A Annunciator power supply replacement tagout; dated 3/8/2004
CAP020504; Inadequate work package review; dated 3/19/2004
CAP020636; Tagout 04-414, 16 out of 20 tags had name discrepancies in empac data base; dated 4/1/2004
CAP020643; PM card inst. Placarded, C/R labeling and drawing differences on Cntmt Dome Fan A; dated 4/1/2004
CAP020703; Equipment label discrepancies found while writing tagout walk downs; dated 4/5/2004
CAP020670; Snapshot Self Assessment; Human Errors and Events; dated 4/2/2004
CAP020731; Tagout Error; dated 4/6/2004
ACE002635; Tagout Error; dated 4/8/2004
CAP020939; Lesson learned CAP on SD-3A work; dated 4/23/2004

CAP020976; WCC not getting work packages reviewed and returned to shops; dated 4/27/2004
CAP019664; Outage suggestion; work flow management; dated 1/23/2004
CAP020017; TCR 2-7 & 2-8 removed without authorization approval; dated 2/1/2004
CAP020421; When restoring condenser water box 1A1; level did not increase immediately; dated 3/13/2004
CE014177; When restoring condenser water box 1A1; level did not increase immediately; dated 3/16/2004
CAP020540; No status control on two-bed demin initiate regen push buttons; dated 3/23/2004
CAP020541; No status control on mixed bed “B” sample stream switch; dated 3/23/2004
CAP020558; Traveling water screen procedure changes needed; dated 3/25/2004
CAP020737; CR AC Train B removed from service; dated 4/7/2004
CE014247; CR AC Train B removed from service; dated 4/8/2004
CAP020757; Work stopped due to expansion of Work Scope; dated 4/8/2004
CAP020808; Request for training; dated 4/13/2004
CAP020910; Conflict between GNP8.2.1, GNP8.2.8 and the Outage Milestones; dated 4/21/2004

4OA3 Event Followup

NMC Correspondence to NRC; Reportable Occurrence 2003-006-00 LER; dated February 10, 2004

Corrective Action Program Documents

CAP001096; Safety Injection Pump Oil Coolers Plugged: GL 89-13 Problems; October 20, 2001
CAP012296; Safety Injection Pump Oil Cooler Pluggage - GL 89-13; July 18, 2002
CAP012388; 'B' Safety Injection Pump Oil Cooler Pluggage - GL 89-13; July 26, 2002
CAP015479; SOER 02-04 Recommendation 3 - Safety Injection Pump Lube Oil Coolers - Biofouling; April 3, 2003
CAP016225; Design Discrepancy Between Safety Injection Pump Lube Oil Cooler's Spares and As-Built; May 1, 2003
CAP016659; SOER 02-04 Recommendation 3 - Plugging of Service Water Piping, Valves, and Heat Exchangers; May 27, 2003
CAP017771; GL 89-13 Test Methodology Questioned by NRC; August 21, 2003
CAP019545; Safety Injection Pump 'A' Lube Oil Cooler Service Water Flow Test and GL 89-13 Cooler Inspection; January 15, 2004
CAP019557; 'B' Safety Injection Pump Lube Oil Heat Exchanger Concerns; January 16, 2004
CAP019586; Adequacy of Acceptance Criteria for Safety Injection Lube Oil Inspections; January 19, 2004
RCE637; Safety Injection Pump Lube Oil Cooler Fouling
IR 95-091R; Failure of the B SI Pump on 4/20/95 Due to Inadequate Thrust Bearing Lubrication

Calculations

MPR-2658; Safety Significance Evaluation for Kewaunee High Head Safety Injection Pump Lube Oil Cooler Degradation and all supporting documentation; Revision 0
Calculation No. C11423; Service Water Flow to the Safety Injection Lube Oil Coolers; Revision 0, Addendum A
Calculation No. C11556; Service Water Flow to Safety Injection Pump 1A/1B Lube Oil Coolers; Revision 0
Calculation No. C11558; Structural Evaluation of Piping and Tubing Changes Associated With the Safety Injection Pump Lube Oil Heat Exchanger Replacement per Design Change Request 003518; Revision 0
Calculation No. C11183; Auxiliary Feedwater Pump Suction Strainer Operability Determination; Revision 1

Procedures

GMP-137; Brush/Tube Scrubber Cleaning Heat Exchanger Tubes and Inspection; Revision G
Preventive Maintenance Procedure PMP-33-01; Safety Injection (QA-1) Pump Maintenance; Revision 0

Other Documents

Event Notification 40452; TS Required Shutdown Due to Both Trains of Safety Injection Declared Inoperable; January 16, 2004
Proto-Power Corporation Assessment; Generic Letter 89-13 Program Assessment for Kewaunee Nuclear Power Plant; December 6, 2002
NRC Generic Letter 89-13; Service Water System Problems Affecting Safety-Related Equipment; July 18, 1989
Letter from Sulzer Pumps to Kewaunee Nuclear Plant; Bingham-Willamette Co. 4X6X9, Type 'CP' Pumps; January 26, 2004
Inspection Results for 'A' and 'B' Safety Injection Lube Oil Coolers; 1992 through 2004
NUREG/CR-5424; Eliciting and Analyzing Expert Judgement

4OA5 Other

American Transmission Company, LLC, Docket No. ER04-754-000, Generation-Transmission Interconnection Agreement with Wisconsin Public Service Corporation; dated April 22, 2004
Licensee Response to Attachment A of Temporary Instruction 2515/156
GNP 08.02.15; General Nuclear Procedure - Maintenance Activity Risk Assessment/ Management Process; Revision A

Condition Reports Initiated for NRC Identified Issues

CAP020647; Procedure Change Request for GMP-148 not Created for AFW Control Valve Replacement DCR-3350

CAP020677; Procedure Enhancements for EPIP-AD_03 and EPIP-AD-04
CAP020850; NRC Project Manager Question on 10 CFR 50.68 (SFP Criticality) and KNPP
CAP020851; Risk Assessment not Performed for Extended Activities
CAP020903; Potential Discrepancy Between Plant and NRC Trip Data; dated 4/21/2004
CAP020932; Probabilistic Risk Assessment Model Diesel Generator Failure Rate Value
CAP021167; NRC Resident Identified Discrepancies Between Internal Containment Spray System Checklist and Drawing
CAP021179; Control Room Portable Stairs Seismic Interaction Evaluation
CAP021228; CAP Not Written for Degraded Equipment CCW Pump 1B PI 11150
CAP021262; NRC Project Manager has Requested the Site to Review Conflicting Information
CAP021288; Component Cooling Water Pump Discharge Pressure Indicators Extent of Condition
CAP021414; Evaluate the Point Beach and KNPP Meteorological Towers
CAP021415; Timeliness and Extent of Condition Evaluation for Agastat Relays
CAP021416; Questioning Attitude and NRC Questions on PMP-0830
CAP21436; Formal Basis for Operator SGTR Training and USAR Update Not Provided
CAP021598; Operability Definition Application in Question
CAP021599; NRC Resident Inspector Concerns on the Turbine Driven Auxiliary Feedwater Pump Operability
CAP021601; NRC Resident Question on SIP Impact with RHR Pump Seal Inleakage into the Auxiliary Building
CAP021613; Increased Oil Sampling of Turbine Driven Auxiliary Feedwater Pump

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
GL	Generic Letter
gph	gallons per hour
gpm	gallons per minute
IMC	Inspection Manual Chapter
KNPP	Kewaunee Nuclear Power Plant
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Record
RHR	Residual Heat Removal
SDP	Significance Determination Process
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report