January 27, 2005

Mr. Joseph Solymossy
Site Vice-President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2004008; 05000306/2004008

Dear Mr. Solymossy:

On December 31, 2004, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on January 7, 2005, with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and to 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, the inspectors identified two NRC-identified findings of very low significance (Green). Both findings also resulted in a violation of NRC requirements. Because these violations were of very low safety significance and were entered into your corrective action program, the NRC is treating the findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant.

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Sincerely,

/RA/

David Passehl, Acting Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-282; 50-306
License Nos. DPR-42; DPR-60

Enclosure: Inspection Report 05000282/2004008; 05000306/2004008
w/Attachment: Supplemental Information

cc w/encl: C. Anderson, Senior Vice President, Group Operations
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	05000282/2004008; 05000306/2004008
Licensee:	Nuclear Management Company, LLC
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	October 1 through December 31, 2004
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector D. McNeil, Senior Operations Engineer R. Orlikowski, Resident Inspector, Monticello R. Jickling, Emergency Preparedness Analyst C. Zoia, Operations Engineer R. Daley, Senior Reactor Engineer T. Bilik, Reactor Engineer J. Neurauter, Reactor Engineer
Approved by:	D. Passehl, Acting Chief Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000282/2004008, 05000306/2004008; 10/01/04 - 12/31/04; Prairie Island Nuclear Generating Plant, Units 1 and 2; Maintenance Effectiveness, Operability Evaluations, and Problem Identification and Resolution.

This report covers a 3-month period of baseline resident inspection and announced baseline inspection on licensed operator requalification and emergency preparedness. The inspection was conducted by the resident inspectors and inspectors from the Region III office. Two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Barrier Integrity

- Green. An inspector identified finding of very low safety significance was identified for the licensee's failure to identify and promptly correct conditions adverse to quality associated with the 121 control room air handler. Specifically, the licensee failed to execute a comprehensive and systematic maintenance troubleshooting process as required by plant procedures. The finding constituted a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." The primary cause of this finding was related to the cross cutting area of Problem Identification and Resolution because the ineffective troubleshooting resulted in a failure to promptly identify and correct conditions adverse to quality and prevent recurrence of 121 CRAH failures. The licensee's ineffective troubleshooting efforts resulted in multiple performance failures of the safety-related control room ventilation system and several unplanned Technical Specification Limiting Condition for Operation entries. The licensee implemented corrective actions to revise the troubleshooting process to meet industry best practices and developed training on troubleshooting techniques.

  The inspectors concluded that the licensee's failure to conduct troubleshooting activities in a comprehensive and systematic manner and was a performance deficiency that warranted significance evaluation. The inspectors determined the finding to be more than minor because degraded and uncorrected conditions associated the 121 control room air handler could become a precursor to a more significant event. Since the finding only represented a degradation of the radiological barrier function provided for the control room, the finding was determined to be of very low safety significance. (Section 1R12)

- Green. An inspector identified finding of very low safety significance was identified for the licensee's failure to identify and promptly correct conditions adverse to quality associated with the low temperature overpressure protection function of the pressurizer power operated relief valves. Specifically, the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer power operated relief valve cycles required to complete the low temperature overpressure protection function for a postulated mass injection event prior to the determination that the function remained operable. The finding constituted a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions.” The primary cause of this finding was related to the cross cutting area of Problem Identification and Resolution because the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to the determination that the function remained operable. The licensee implemented corrective actions that included the identification of LTOP design basis requirements; establishment of new and more conservative LTOP design basis; and the development, installation, and testing of a recurring temporary modification.

The inspectors determined that a performance deficiency existed with the problem identification and resolution actions taken by the licensee during development and review of the operability recommendation. The finding was more than minor since it could be viewed as a precursor to a more significant event such as a failure of the reactor coolant system barrier integrity and affected the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide release caused by accidents and events, and was associated cornerstone attributes of reactor coolant system equipment and barrier performance. Since sufficient mitigating capabilities were maintained and no non-compliance with Technical Specifications were identified, the finding was determined to be of very low safety significance. (Sections 1R15)

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

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period shut down for continuation of the refueling and steam generator (SG) replacement outage 1R23. The unit was made critical on November 23, 2004, and brought to 98 percent power by November 29, 2004. The unit was limited to 98 percent power due to generator loading limitations because of hydrogen seal oil system deficiencies. The unit operated at about 98 percent power for the remainder of the inspection period.

Unit 2 was operated at or near full power with the following exceptions. On October 6, 2004, power was reduced to approximately 92 percent for maintenance on a heater drain tank pump motor. The unit was returned to full power after 8 hours. On October 31, 2004, power was reduced to approximately 25 percent to add oil to a reactor coolant pump lower bearing oil reservoir. The unit was returned to full power after 12 hours. On November 12, 2004, power was reduced to approximately 93 percent for maintenance on a heater drain tank pump. The unit was returned to full power after 15 hours. On November 17, 2004, the unit was taken off-line and shut down for a Technical Specification (TS) required action when leaks were discovered on two containment fan coil units and both trains of containment cooling were declared inoperable. The unit was returned to full power on November 20, 2004, and operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1RST Post-Maintenance and Surveillance Testing (71111.ST) (Pilot)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors selected four post-maintenance testing activities that affected risk-significant systems or components associated with the mitigating systems and barrier integrity cornerstones, completing four post-maintenance testing inspection samples. The following post-maintenance testing activities were assessed by inspectors:

- Surveillance Procedure (SP) 1098 following the 10 year preventative maintenance and inspection of the 11 station battery charger on October 6, 2004;
- SP 1090A following the replacement of the mechanical seal on the 11 containment spray pump on November 5, 2004;
- SP 1137 following corrective maintenance on safety injection motor operated valve 32074 on November 10, 2004; and
- Preventive Maintenance Procedure (PM) 3132-1-11 following corrective maintenance on the 11 turbine-driven auxiliary feedwater (TDAFW) pump on November 19, 2004.

During the performance of these inspections, the inspectors conducted in-plant observations and/or in-office reviews of documentation to ensure that testing activities and the post-maintenance test procedures met the following attributes:

- testing activities satisfied the test procedure acceptance criteria;
- effects of the testing had been adequately addressed prior to the commencement of the testing;
- measurement and test equipment calibrations were current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- affected systems or components were removed from service in accordance with approved procedures;
- testing activities were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data/results were accurate, complete, and valid;
- test equipment was removed after testing;
- equipment was returned to a position or status required to support the operability of the system in accordance with approved procedures; and
- all problems identified during the testing were appropriately documented in the corrective action program.

The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Surveillance Testing

a. Inspection Scope

During this inspection period, the inspectors completed six inspection samples, comprised of the following surveillance testing activities:

- SP 1092C, SI [Safety Injection] Check Valve Test (Head Off), Part C: Accumulator Flow Path Verification on October 30, 2004;
- SP 1083, Unit 1 Integrated SI Test With a Simulated Loss of Offsite Power on November 11, 2004;
- SP 1070, Reactor Coolant System Integrity Test on November 17, 2004;
- SP 1750, Unit 1 Post Outage Containment Close-Out Inspection on November 22, 2004;
- SP 1036, Turbine Overspeed Trip Exercise on November 23, 2004; and
- SP 1001AA/2001AA, Daily Reactor Coolant System Leakage Test on December 3, 2004.

The observation of SP 1092C as an inspection sample completed the Inspection Procedure 71111.22 requirement to observe one inservice inspection related surveillance test per quarter. Additionally, the observation of SP 1001AA/2001AA as an inspection sampled completed the Inspection Procedure 71111.22 requirement to observe one to three reactor coolant system leakage surveillance tests per year.

During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to verify that:

- preconditioning does not occur;
- effects of the testing had been adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria was clearly stated, demonstrated operational readiness, and was consistent with the system design basis;
- plant equipment calibration was correct, accurate, properly documented, and the calibration frequency was in accordance with TS, the Updated Safety Analysis Report (USAR), procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequency met TS requirements to demonstrate operability and reliability;
- the tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data/results were accurate, complete, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers (ASME) Code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data have been accurately incorporated in the test procedure;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented in the corrective action program.

The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

During this inspection, the inspectors completed one adverse weather inspection sample. The inspectors selected the Unit 1 and Unit 2 condensate storage tanks, the safety-related Unit 2 diesel generators D5 and D6, and the safety-related diesel-driven cooling water pumps. The inspectors completed system walkdowns and reviewed applicable procedures and associated records to verify that the risk-significant systems were adequately protected against impending cold weather.

The inspectors used the licensee checklists and procedures to verify that the systems were aligned as required. In addition, the inspectors reviewed the corrective action program action requests (CAPs) and work orders (WOs) to verify that the licensee had entered problems identified with cold weather operations into the corrective action system and was taking the appropriate corrective and compensatory actions.

b. Findings

No findings of significance were identified.

1R02 Evaluation of Changes, Tests, or Experiments (71111.02)

Steam Generator Replacement (50001)

a. Inspection Scope

From August 30, 2004, through September 3, 2004, and October 4, 2004, through October 8, 2004, the inspectors reviewed the licensee's evaluations for the design changes associated with the replacement steam generator (RSG) to determine, for each change, whether the requirements of 10 CFR 50.59 had been appropriately applied. Specifically, the inspectors reviewed screenings and safety evaluations associated with modifications to the:

- RSG and secondary piping;
- RSG insulation replacement and platform modifications;
- RSG nozzle dams;
- SG rigging outside containment; and
- SG rigging and transport inside containment.

The inspectors used, in part, Nuclear Energy Institute 96-07, "Guidelines for 10 CFR 50.59 Implementation," Revision 1, to determine acceptability of the completed screenings and evaluations. The Nuclear Energy Institute document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments," dated November 2000. The inspectors also consulted Part 9900 of the NRC Inspection Manual, "10 CFR Guidance for 10 CFR 50.59, Changes, Tests, and Experiments." Other records reviewed by the inspectors are identified in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors performed three inspection samples comprised of partial system walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors utilized the valve and electric breaker checklists listed in the Attachment to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors reviewed outstanding WOs and CAPs associated with the trains to verify that those documents did not reveal issues that could affect train function. The inspectors used the information in the appropriate sections of the USAR to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- diesel generator D5 during the unavailability of diesel generator D6 on November 9, 2004;
- 12 cooling water strainer during the unavailability of the 11 cooling water strainer on December 20, 2004; and
- 22 TDAFW pump during the unavailability of the 21 motor-driven auxiliary feedwater pump on December 23, 2004.

b. Findings

No findings of significance were identified.

1R05 Fire Protection Area Walkdowns (71111.05)

a. Inspection Scope

The inspectors conducted in-office and in-plant reviews of portions of the licensee’s Fire Hazards Analysis and Fire Strategies to verify consistency between these documents and the as-found configuration of the installed fire protection equipment and features in the fire protection areas listed below. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events; their potential to impact equipment which could initiate a plant transient; or their impact on the plant’s ability to respond to a security event. The inspectors assessed the control of transient combustibles and ignition sources, the material and operational condition of fire protection systems and equipment, and the status of fire barriers. The following 11 fire areas were inspected by in-plant walkdowns supporting the completion of 11 fire protection zone walkdown samples:

- Fire Area 35, 21 battery room on October 6, 2004;
- Fire Area 36, 22 battery room on October 6, 2004;
- Fire Area 3, 121 control room chiller room on October 7, 2004;
- Fire Area 10, train A event monitoring room on October 7, 2004;
- Fire Area 12, operations support center on October 7, 2004;
- Fire Area 15, access control on October 7, 2004.
- Fire Area 16, train B event monitoring room on October 7, 2004;
- Fire Area 66, 693 foot elevation storage room on October 7, 2004;
- Fire Area 92, 122 control room chiller room on October 7, 2004;
- Fire Area 127, bus 211/212 room on October 7, 2004; and
- Fire Area 1, Unit 1 reactor building (containment) on October 8, 2004.

The inspectors also reviewed the CAPs listed in the Attachment to verify that the licensee was identifying fire protection issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. As appropriate, the corrective actions were reviewed to determine if the actions taken were sufficient.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On October 5, 2004, the inspectors conducted an in-plant walkdown of the Unit 1 and Unit 2 cooling water pump rooms in the screenhouse completing one internal flood protection inspection sample. This area contains safety-related and risk-significant equipment from Unit 1 and Unit 2, including both trains of the cooling water pumps. The inspectors reviewed the applicable sections of the USAR, design bases documents, and plant procedures associated with internal flooding of the screenhouse. The inspectors verified by physical inspection that the licensee maintained the material condition of piping systems in these areas. The inspectors also verified that drain paths from these areas had been maintained and that there were no accumulation of loose materials that could plug critical drain paths. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors assessed the effectiveness of the licensee's program for monitoring degradation of the reactor coolant system boundary and risk-significant piping system boundaries and completed a total of three inspection samples.

For the first inspection sample, the inspectors conducted an onsite and record review of three nondestructive examination activities to verify that the activities were performed in accordance with ASME Boiler and Pressure Vessel Code requirements. The activities reviewed were the following:

- liquid penetrant examination of a Unit 1 pressurizer nozzle to safe end weld, weld 29A;
- ultrasonic examination of the Unit 1 valve to pipe weld connecting RS-19-1 to MS-19; and
- bare metal visual examination of the Unit 1 vessel upper head penetrations.

The inspectors also reviewed the following examinations from the previous outage with recordable indications that have been accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code:

- ultrasonic test of a Unit 1 feedwater nozzle weld (indication found to be acceptable per ASME Code Section XI, IWC- 3510); and
- ultrasonic test of a Unit 1 feedwater nozzle weld (indication found to be acceptable per ASME Code Section XI, IWB-3510).

The inspectors were unable to review any pressure boundary welds because none were completed since the beginning of the previous refueling outage.

For the second sample, the inspectors directly observed the bare metal visual examination in its entirety and performed direct observation of portions of the reactor vessel head. The visual examination quality was confirmed by the licensee by ensuring 360 degree coverage of the head penetrations using a bar with a mirror on the end. The inspectors verified that this method allowed a complete inspection of the penetration annuluses. Additionally, records of the inspection were reviewed subsequent to the examination by the inspectors.

The inspectors verified that the head inspection activities were performed in accordance with the requirements of NRC Order EA-03-009, and verified that indications were dispositioned in accordance with the ASME Code. There were no recordable indications/relevant conditions, so the inspectors could not review any examinations with recordable indications that were accepted by the licensee for continued service. Since the licensee had not performed any repairs to upper vessel head penetrations, the inspectors did not perform a verification of the appropriateness of the welding process or subsequent examinations of repaired head penetrations.

For the third sample, the inspectors directly observed the licensee perform their boric acid walkdown. Additionally, the inspectors performed an independent visual examination. During these in-plant observations, the inspectors also verified that the licensee's visual inspection emphasized locations where boric acid leaks could cause degradation of safety-significant components. These observations were included in Inspection Report (IR) 05000282/2004007; 05000306/2004007.

The inspectors reviewed the completed record of the licensee's boric acid walkdown as documented in SP 1405, "Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment." The licensee's "Boric Acid Control Program" requires boric acid corrosion evaluations to be documented in the corrective action program. The inspectors reviewed three CAPs generated as a result of the licensee's walkdown:

- CAP 038374, "ASME XI/BACC [boric acid corrosion control] Relevant Leak Discovered on CV-31450 During BACC Walkdown";
- CAP 038376, "BACC Relevant Leak Found on 1PT-729 During BACC Walkdown"; and
- CAP 038420, "ASME XI and BACC Relevant Leak Discovered During BACC Walkdown."

The inspectors also reviewed the engineering evaluations performed for these three CAPs and verified that the appropriate ASME requirements were maintained in the eventual disposition of each issue.

The inspectors also verified that the licensee was appropriately identifying inservice inspection (ISI) problems by reviewing the licensee's corrective action procedure and by verifying the appropriateness of the corrective actions associated with a sampling of ISI related problems documented by the licensee in their corrective action program. Specifically, the inspectors reviewed the following ISI related CAPS: CAP 027259, "Dissimilar Metal Weld Examinations"; CAP 027781, "VT-1 [visual test] of Flange Bolting Was Not Performed as Required"; and CAP 038229, "Relief Request Identified Incorrect Item Number."

Because the licensee replaced Unit 1 SGs during this refueling outage, SG tube inspection activities were not inspected. Instead, the SG replacement activities were inspected in accordance with inspection procedure (IP) 50001. Results of this effort are included in Section 4OA5 of this report. These inspection activities do not constitute an inservice inspection activity sample

Additionally, by performing a sample review of ISI related operating experience (OE) evaluations conducted by the licensee, the inspectors determined that the licensee was correctly assessing the applicability of OE to the plant.

b. <u>Findings</u>

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Quarterly Observation of Licensed Operator Simulator Training

a. Inspection Scope

On November 30, 2004, the inspectors performed a quarterly review during licensed operator requalification training in the simulator, completing one licensed operator requalification inspection sample. The inspectors observed a crew while in training during an annual requalification examination in the plant's simulator facility. The inspectors compared crew performance to licensee management expectations. The inspectors verified that the crew completed all of the critical tasks for the scenario. For any weaknesses identified, the inspectors observed that the licensee evaluators noted the weaknesses and discussed them in the critique at the end of the session.

The inspectors assessed the licensee's effectiveness in evaluating the requalification program, ensuring that licensed individuals would operate the facility safely and within the conditions of their licenses, and evaluated licensed operator mastery of high-risk operator actions. The inspection activities included, but were not limited to, a review of high-risk activities, emergency plan performance, incorporation of lessons learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of TS, simulator fidelity, and licensee critique of performance.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of individual Job Performance Measure operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during calender year 2004. The overall results were compared with the significance determination process in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process."

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed a repetitive maintenance activity to assess maintenance effectiveness, including maintenance rule (10 CFR 50.65) activities, work practices, and common cause issues. The inspectors performed one system/train function oriented maintenance effectiveness sample. The inspectors assessed the licensee's maintenance effectiveness associated with repetitive failures of the 121 control room air handling unit on November 2, 2004.

The inspectors reviewed the licensee's maintenance rule evaluations of equipment failures for maintenance preventable functional failures and equipment unavailability time calculations, comparing the licensee's evaluation conclusions to applicable Maintenance Rule (a)1 performance criteria. Additionally, the inspectors reviewed scoping, goal-setting (where applicable), performance monitoring, short-term and long-term corrective actions, functional failure definitions, and current equipment performance status.

The inspectors reviewed CAPs for significant equipment failures associated with the 121 control room air handling unit to ensure that those failures were properly identified, classified, corrected, and that the timeliness of the actions were commensurate with the significance of the identified issues. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

Introduction

The inspectors investigated the details associated with the repetitive failures of the 121 control room air handler (CRAH) and identified a finding of very low significance that was also determined to be a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions. Specifically, the licensee failed to execute a structured and comprehensive troubleshooting process as required by plant procedures. The licensee's ineffective troubleshooting efforts resulted in multiple performance failures of the safety-related control room ventilation system and several unplanned TS Limiting Condition for Operation (LCO) entries, including one entry into TS 3.0.3.

Description

On April 2, 2004, a self-revealing event occurred when the 121 control room air handler (CRAH) stopped for unknown reasons. Plant operators entered the appropriate 7-day TS LCO for one train of the control room special ventilation system (CRSVS) inoperable. The licensee quickly focused troubleshooting resources on the CRAH motor and motor control center (MCC) breaker. The licensee determined that motor overload relay (MOLR), often referred to as the thermal overload relay, was not tripped. The 121 CRAH unit was started and the plant electricians measured motor starting current. No abnormalities were noted with either the motor or the MCC breaker. On April 3, the licensee performed thermography measurements at the MCC with the results interpreted as normal.

The system engineer initiated WO 0405101 to perform Electrical Preventive Maintenance Procedure (PE) MCC-W5, "Preventive Maintenance Breaker 112G-5 (MCC 1T1-B3)," Revision 5, on the 121 CRAH breaker, perform resistance checks on local and remote control switches, and perform testing on the 42X relay. These troubleshooting actions were not completed prior to the declaration of operability and were scheduled for completion on April 14, 2004.

On April 3, 2004, at 5:30 p.m. following 22 hours of problem free operation, the shift manager declared the 121 CRSVS operable based on the justification provided in Operability Recommendation (OPR) 000485. The licensee's basis for operability included the investigation and troubleshooting results for the motor and breaker and nearly 24 hours of error free operation. No root or apparent cause for the 121 CRAH failure was identified.

On April 14, 2004, the execution of WO 0405101 was canceled by the maintenance manager. The basis for this action were concerns that the plant would be placed in a condition where one failure (i.e., the failure of the 122 CRSVS or the B train of the safeguards chilled water system) would result in a TS 3.0.3 entry and a dual unit shutdown for work that did not have a clearly delineated troubleshooting plan and had not been reviewed using the voluntary LCO process. The maintenance manager wanted a spare breaker on-site prior to performing the work order.

On May 7, 2004, at 5:00 a.m. the licensee performed routine swap of CRSVS starting the 121 CRSVS train. Approximately 2 hours later, operators identified that the 121 CRAH tripped and declared the train inoperable. An initial investigation identified that the MOLR tripped. The system engineer was assigned to troubleshoot the 121 CRAH. The licensee implemented two work orders, WO 0400270 and WO 0405101, to troubleshoot the CRAH. WO 0400270 directed the performance of PM 3147-1-121, "121 Control Room Air Handler 6 Month Inspection," Revision 9, to look for mechanical damage. The licensee issued a temporary change notice to WO 0405101 limiting its use to the inspection of the MOLR.

The mechanical inspection identified that a pressure sensing tube associated with the differential pressure switch was plugged. The function of this switch was to automatically advance the roll filter on a high differential pressure. This resulted in a plugged filter in the ventilation system airstream. The plugged sensing line was cleaned and the roll filter advanced. At 7:19 p.m. the licensee started the 121 CRAH for its post-maintenance test. Approximately 3 hours into the post-maintenance test, the 121 CRAH stopped for unknown reasons. Operators checked the breaker and found that the MOLR had not tripped. The licensee wrote a temporary change notice to perform the majority of PE MCC-W5 as specified in WO 0405101. During the inspection, plant electricians identified degraded contacts associated with the 42X relay and replaced these contacts. On May 9, the licensee satisfactorily performed post-maintenance test and declared the 121 CRAH operable based on the identification and correction of the high differential pressure switch and the replacement of the of the 42X relay contacts.

On June 23, 2004, with the 122 CRSVS inoperable due to planned maintenance on the B train of the safeguards chilled water system (a required support system), the licensee found the 121 CRAH tripped resulting in the inoperability of the 121 CRSVS. The licensee entered TS 3.0.3. Because the licensee had completed the physical maintenance on the safeguards chilled water system, the shift manager was able to complete the maintenance activity document review and declare the safeguards chilled water system operable. TS 3.0.3 was exited within minutes of its entry.

Upon initial inspection, the licensee found the 121 CRAH MOLR tripped again. In response to this event the licensee initiated a root cause evaluation (RCE), removed the MCC bucket for investigation, and wrote WO 0406353 for another mechanical inspection. Electrical maintenance personnel replaced the MOLR and one additional contact not replaced following the May failure. Mechanical maintenance identified that the sheaves on the fan motor shaft and on the fan axle were 3/16 inch to 1/4 inch out of alignment. The sheaves were re-aligned; the MCC bucket was re-installed with no abnormalities identified were found with MOLR, contactor, or auxiliary contacts for breaker 112G-5; and the fan was started and test run. Maintenance personnel noted that the running motor current after the sheave alignment was approximately two amps less than previous measurements.

On June 25, 2004, at 10:35 p.m. following over 12 hours of problem free operation, the shift manager declared the 121 CRSVS operable based on the justification provided in OPR 000502. The licensee stated that the cause of the failures could not be conclusively determined. The licensee’s determination of operability was based on reasonable assurance provided by the replacement of the thermal overload relay, alignment of the fan and motor of the CRAH, and the physical inspection and testing of all other components that have the potential to cause a thermal overload trip. The licensee used a systematic method of troubleshooting in the last case.

On November 2, 2004, the inspectors commenced a review of the self-revealing failures of the 121 CRAH that occurred between April 2 and June 25, 2004. The inspector conducted a review of the licensee’s RCE 000192, “Repetitive Troubleshooting of 121 Control Room Air Supply Fan,” Revision 1 and other corrective action program documentation applicable to these events. The inspectors concluded that the licensee’s ineffective troubleshooting resulted in a failure to identify and correct the root and/or apparent causes of the 121 CRAH failures. For example, following the April 2, 2004, failure that did not result in the trip of the MOLR, many electrical parameters were checked with no abnormal conditions found. Based on the symptoms, the licensee expended troubleshooting resources on several potential causes for the failure that were not probable since the MOLR or the breaker did not trip. More importantly, several potential causes for the failure were not investigated even though the symptoms would support their inclusion in a troubleshooting plan. This was evident when the licensee decided not to perform appropriate portions of PE MCC-W5 that would have checked the motor contactor and auxiliary contacts prior to the declaration of operability. The licensee declared the 121 CRAH operable with no root or apparent cause identified and potential causes for the failure un-investigated and indeterminate. The licensee demonstrated ineffective troubleshooting again following the May 7, 2004, failures. Not until the June 23, 2004, failure did the licensee use a comprehensive and systematic troubleshooting process.

Additionally, in response to the May 7, 2004, failure, the licensee performed an apparent cause evaluation (ACE) 008837. The ACE did not identify the failure to use procedurally required systematic troubleshooting methodology found in Administrative Work Instruction (AWI) 5AWI 3.2.10, "Investigation and Troubleshooting," Revision 9 or 5AWI 3.2.11, "Troubleshooting Process," Revision 0. Additionally, the inspector identified that the licensee's extent of condition review failed to assess the condition of the auxiliary contacts in the other safety-related MCC buckets of the same type. This could have been significant since the spent fuel pit cooling pumps utilized the same type of MCC bucket and had been subject to maintenance at the same preventive maintenance frequency as the 121 CRAH. The spent fuel pit pumps were relied upon during the recent refueling outage (1R23) for decay heat removal during the complete offload of the Unit 1 core. The licensee entered the inspectors concerns associated with the extent of condition review into their corrective action program with CAP 040441.

Analysis

The inspectors concluded that the licensee's ineffective troubleshooting activities resulted in a failure to promptly identify and correct conditions adverse to quality and prevent recurrence of subsequent 121 CRAH failures. The licensee's failure to conduct troubleshooting activities in a comprehensive and systematic manner was not in accordance with procedural requirements, management expectations, and was a performance deficiency that warranted significance evaluation. The inspectors determined the finding to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The finding was more than minor because degraded and uncorrected conditions associated with important barrier integrity cornerstone structures, systems, and components such as the 121 CRAH could become a precursor to a more significant event. The inspectors also determined that the finding impacted the cross cutting area of Problem Identification and Resolution because the ineffective troubleshooting resulted in a failure to promptly identify and correct conditions adverse to quality and prevent recurrence of 121 CRAH failures.

The inspectors completed the significance determination of this finding using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated September 10, 2004. Since this finding only represents a degradation of the radiological barrier function provided for the control room, the Phase 1 Significance Determination worksheet indicated the finding to be of very low safety significance (Green).

Enforcement

10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, states in part that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, on April 2 and May 7, 2004, the licensee failed to promptly identify and correct failures of the 121 CRAH unit that resulted in unplanned LCO entries. Additionally, on June 23, 2004, the 121 CRAH failed again and required entry into TS 3.0.3 for a brief period of time (2 minutes). Because this finding is of very low safety significance, and has been entered into the licensee's corrective action

program with CAP 037262, this finding is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2004008-01; 05000306/2004008-01). The licensee completed RCE 000192 and identified several corrective actions for implementation. Corrective Action (CA) 009399 implemented corrective actions to revise the troubleshooting procedure to meet industry best practices and CA 009400 developed training on troubleshooting techniques. Both of these corrective actions have been implemented and training will be completed during the first quarter 2005 training cycle.

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

a. Inspection Scope

The inspectors reviewed risk assessments for the following combined maintenance activities or emergent plant conditions completing eight risk assessment and emergent work control inspection samples:

- the simultaneous unavailability of the 125 service air compressor, bus 150, D2 diesel generator, 122 control room chiller, 22 component cooling water heat exchanger, 22 and 24 containment fan coil units, motor operated valve 32027, and motor operated valve 32030 on October 15, 2004;
- the simultaneous unavailability of the 121 and 122 instrument air compressors, the 12 motor-driven auxiliary feedwater pump, and diesel generator D2 resulting in an Orange risk condition on October 18, 2004;
- the simultaneous unavailability of the 22 and 23 containment fan coil units on November 18, 2004;
- the emergent failure of the bus 26 load sequencer with the 13 charging pump, 11 main feedwater pump, 121 intake bypass gate, and 123 air compressor out-of-service on November 22, 2004;
- the emergent failure of the bus 15 load sequencer with the bus 26 load sequencer, the 13 charging pump, 11 main feedwater pump, 121 intake bypass gate, and 123 air compressor out-of-service on November 22, 2004;
- the emergent failure of the 121 instrument air compressor with the 123 instrument air compressor out-of-service on November 24, 2004;
- the emergent failure of the Unit 2 volume control tank 2LT-141 on December 1, 2004; and
- the simultaneous unavailability of the 12 residual heat removal pump, the 11 charging pump, the 12 containment spray pump, and diesel generator D2 on December 13, 2004.

During these reviews, the inspectors compared the licensee’s risk management actions to those actions specified in the licensee’s procedures for the assessment and management of risk. The inspectors verified that evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate. The inspectors used the licensee’s daily configuration risk assessment records, observations of shift turnover meetings, observations of daily plant status meetings, and observations of shiftily outage meetings to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were communicated to the necessary personnel. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Plant Evolutions and Events (71111.14)

.1 Operator Response to a Partial Loss of Instrument Air

a. Inspection Scope

On October 18, 2004, the inspectors observed the control room operators' response to an unplanned partial loss of instrument air completing one operator performance during non-routine plant evolutions and events inspection sample. During planned maintenance the 122 air compressor was out of service and the 121 air compressor was stopped because of a cooling water leak on the aftercooler drain valve. Instrument air pressure decayed from a normal value of 125 pounds per square inch gauge (psig) to approximately 97 psig. The inspectors observed that operators entered abnormal operating procedure C34 AOP1 and verified their actions were consistent with the procedures. The documents reviewed during this inspection are listed at the end of this report.

b. Findings

No findings of significance were identified.

.2 Unit 1 Heat Up and Start Up from Refueling Outage 1R23

a. Inspection Scope

On November 15 and 16, 2004, inspectors conducted in-plant observations of operator performance during the heat up of the reactor coolant system and the transition from operating mode five to mode four, and from operating mode four to mode three completing one operator performance during non-routine plant evolutions and events inspection sample. The inspectors also observed the licensee's assessment of leakage emanating from two reactor vessel head instrument port conoseals, and the operators establishment and control reactor coolant heat up. The inspectors compared the operator actions to those actions specified in the governing operating procedures, and reviewed applicable operating logs.

The inspectors reviewed the licensee's actions and corrective action program documents to verify that the licensee identified issues at an appropriate threshold and entered them into their corrective action program in accordance with station corrective action procedures. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.3 Unit 2 TS Required Shutdown and Restart

a. Inspection Scope

On November 17, 2004, inspectors observed the response of operators to identified leakage from two Unit 2 containment fan cooling units completing one operator performance during non-routine plant evolutions and events inspection sample. On November 20, 2004, inspectors observed operator performance during the restart of Unit 2 following repairs to the containment fan cooling units completing one additional operator performance during non-routine plant evolutions and events inspection sample for a total of two inspection samples.

The inspectors reviewed the licensee’s entry into Limiting Condition for Operation comparing their actions to the actions specified in the Prairie Island TS. The inspectors observed the shutdown and the subsequent restart of Unit 2 comparing operator actions to those actions specified in the appropriate operating procedures. The inspectors reviewed the licensee’s actions and corrective action program documents to verify that the licensee identified issues at an appropriate threshold and entered them into their corrective action program in accordance with station corrective action procedures. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of four operability evaluations completing four operability evaluation inspection samples. The inspectors conducted these inspections by in-office review of associated documents and in-plant observations of affected areas and plant equipment. The inspectors compared degraded or nonconforming conditions of risk-significant structures, systems, or components associated with mitigating systems against the functional requirements described in TS, USAR, and other design basis documents; determined whether compensatory measures, if needed, were implemented; and determined whether the evaluation was consistent with the requirements of 5AWI 3.15.5, “Operability Determinations.” The following operability evaluations were reviewed:

- OPR 000361, that documented the operability of the pressurizer power operated relief valves (PORV) for the low temperature overpressure protection (LTOP) safety function following identified concerns associated with the capacity of the back up air accumulators on September 22, 2004;

- OPR 0000505, that documented the operability of relief valves in component cooling water piping for the excess letdown heat exchangers that were not included in the ASME Section XI testing program on November 3, 2004;
- CAP 039567 prompt operability determination for a deficient conditions noted on air operated valve for the component cooling water to the excess letdown heat exchanger outlet valve, CV-31252, on November 7, 2004; and
- OPR 000114, that documented the operability determination for acceptable performance of the Containment Spray safeguards actuation in view of a condition where annunciator 47019-0103, “Containment Spray Actuated”, cleared with only one of two trains reset on November 12, 2004.

b. Findings

Introduction

The inspectors identified a finding of very low significance that was also determined to be an NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions. Specifically, the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to the determination that the function remained operable. The non-conservative conclusions were incorporated into the design basis and referenced in OPR 000361.

Description

On November 28, 2002, the licensee identified issues associated with the required seat load for the pressurizer PORVs. To achieve the required seat load, necessitated setting the lower bench set pressure to approximately 67 psig. The back up air accumulators were sized for a bench set pressure of 61 psig. As the bench set pressure was increased, higher air pressure was required to fully open the valve and reduced the number of full stoke cycles achievable using the back up air accumulators.

On November 29, 2002, the licensee reduced the bench set pressure to 57 psig on CV-31232 and 58 psig on CV-31231 and demonstrated the required closing thrust requirements at the as-left pressures using air-operated valve diagnostic methods. Additionally, the diagnostic analysis of these two valves indicated a minimum air pressure of 85.8 and 82.1 psig were required to fully open the pressurizer PORVs. The licensee performed calculation ENG-ME-537 to determine the number of valve cycles possible based on the accumulator size. At the reduced lower bench set pressure of 57 and 58 psig, calculation results indicated that 12 valve cycles could be accomplished with an initial accumulator pressure of 95 psig and 18 cycles with an initial accumulator pressure of 100 psig.

On November 30, 2002, the licensee completed OPR 000361 justifying the operability of the LTOP system. USAR Section 4.4.3.3 states that the backup air accumulator design permits approximately 15 cycles with 36 cubic feet of air at an initial air pressure of 80 to 100 psig. The basis for the 15 pressurizer PORV cycles was not known or understood by the licensee and was stated as such in OPR 000361. The licensee concluded that LTOP system was operable since calculation ENG-ME-537 demonstrated 12 to 18 cycles of a pressurizer PORV with a backup accumulator pressure of 95 to 100 psig. In December of 2002 , the licensee established plant condition that required LTOP system to be operable during the heat up of Unit 1 following refueling outage 1R22.

On September 8, 2004, the licensee's Operations Committee reviewed OPR 000361 and concluded that the evaluation was sound and was acceptable to proceed with the Unit 1 refueling outage 1R23. On September 11, 2004, Unit 1 entered a mode of operation where the LTOP system was required to be operable particularly during the cooldown of the reactor coolant system below 310 degrees Fahrenheit.

On September 22, 2004, the inspectors reviewed OPR 000361 and challenged the licensee's conclusion of operability since it was stated that no basis could be determined for operation of the pressurizer PORVs approximately 15 cycles. The inspectors were concerned that without a clear understanding of the design basis for the 15 pressurizer PORV cycles , that reasonable assurance of operability of the LTOP function could not be demonstrated by 12 cycles of the pressurizer PORV obtainable at an accumulator pressure of 95 psig. The licensee conducted a search of design basis documentation to establish the design basis for the 15 pressurizer PORV cycles and identified a licensee amendment request dated August 4, 1978, that appears to establish a design basis for the 15 pressurizer PORV cycles. It assumes the isolation letdown with one charging pump operating at the beginning of the LTOP event.

The licensee told the inspectors that analyses were to be performed to demonstrate the acceptability of the air accumulators when supplemented by additional air bottles installed under recurring temporary modification 04T175 to support pressurizer PORV operations for a design basis change. The new design basis would assume that a let down isolation would occur with one charging pump operating at a maximum flow rate of 60 gallons per minute (gpm) and one safety injection pump operating at its design flow rate of 600 gpm. Included in the analyses for the new design basis would be a case for the current LTOP design basis of a letdown isolation with one charging pump operating at 40 gpm. On October 15, 2004, that analysis concluded that 32 cycles of the pressurizer PORV would be required to mitigate the mass injection event for the current LTOP design basis and 143 cycles to satisfy the safety function for the new design basis. The analysis results clearly demonstrated the inadequacy of the existing design basis calculation and the non-conservative basis for OPR 000361.

Analysis

The inspectors determined that a performance deficiency existed with the problem identification and resolution actions taken by the licensee during development and review of OPR 000361. Specifically, the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to the determination that the function remained operable. The inspectors concluded that an adequate justification providing reasonable assurance that the LTOP function would be accomplished if required was not attainable without a clear and complete understanding of the system's design basis.

Additionally, the licensee missed two opportunities to identify and correct the deficient understanding of the design basis of LTOP system. The first opportunity was missed during the initial development and review OPR 000361 in November 2002, and the second opportunity was missed during the Operations Committee review of OPR 000361 prior to refueling outage 1R23 in September 2004. Since the design basis was never clearly understood, the basis for the conclusion of operability arrived at by the licensee and documented in OPR 000361 was nonconservative and indeterminate. The inspectors also determined that the finding impacted the cross cutting area of Problem Identification and Resolution because the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to determination that the function remained operable.

The current state of operability is no longer in question since the development and installation recurring temporary modification 04T175. The temporary modification provides sufficient air capacity to support the new design basis requirements of an assumed let down isolation with one charging pump operating at a maximum flow rate of 60 gpm and one safety injection pump operating at its design flow rate of 600 gpm with a single failure. However, the historical operability back to 1988 is still in question. The licensee conducted a evaluation of the historical operability with Condition Evaluation (CE) 006461. Upon review, the inspectors challenged the licensee's conclusion of operable because the licensee failed to evaluate the case where the containment isolation valve was assumed to fail closed as the single failure. The licensee agreed that the scenario needed to be evaluated and entered it into their corrective action program with CAP 040435 and CAP 040442. The evaluation is expected to be completed in January 2005.

The inspectors determined the finding to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The finding was more than minor since it could be viewed as a precursor to a more significant event such as a failure of the reactor coolant system barrier integrity. Furthermore, the finding affects the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide release caused by accidents and events, and was associated cornerstone attributes of reactor coolant system equipment and barrier performance, specifically the LTOP function of the pressurizer PORVs.

The inspectors determined that the LTOP function is only required when the reactor is shutdown and reactor coolant cold leg temperature is less than 310 degrees Fahrenheit. The determination of significance for this finding was evaluated using Appendix G, "Shutdown Operations," of IMC 0609, "Significance Determination Process (SDP)." The specific plant conditions that existed during periods when the LTOP function was required were evaluated for significance using Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both Pressurized Water Reactors and Boiling Water Reactors, Checklists 1 and 2." Since sufficient mitigating capabilities were maintained and no non-compliance with Prairie Island LTOP TS 3.4.12 or 3.4.13 were identified by inspectors, the significance was determined to be of very low safety significance (Green).

Enforcement

10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” states in part that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, on or about November 30, 2002, and September 8, 2004, the licensee failed to identify that important information associated with LTOP design basis was not included in OPR 000361. The design basis information was necessary to demonstrate with reasonable assurance that the LTOP function would be satisfactorily accomplished during a postulated mass injection event. Because this finding is of very low safety significance, and has been entered into the licensee’s corrective action program with CAP 039539 and CAP 040417, this finding is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2004008-02; 05000306/2004008-02). The licensee has implemented corrective actions that included the identification of LTOP design basis requirements; establishment of new and more conservative LTOP design basis; and the development, installation, and testing of a recurring temporary modification 04T175.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Review of Selected Workarounds

a. Inspection Scope

The inspectors reviewed selected OWAs to determine if the mitigating system function was affected, completing two OWA samples. Specifically, the inspectors evaluated if the operator’s ability to implement abnormal and emergency operating procedures was affected by the workaround. The inspectors considered operator workarounds that have not been evaluated by the licensee and that have been formalized as long-term corrective action for a degraded or non-conforming condition. They also reviewed OWAs that increase potential for personnel error including OWAs that:

- required operations contrary to past training or require more detailed knowledge of the system than routinely provided;
- required a change from longstanding operational practices;
- required operation of system or component in a manner that is different from similar systems or components;
- created the potential for the compensatory action to be performed on equipment or under conditions for which it is not appropriate;
- impaired access to required indications, increase dependence on oral communications, or require actions under adverse environmental conditions; or
- required the use of equipment and interfaces that had not been designed with consideration of the task being performed.

The following OWAs were reviewed by the inspectors:

- problems associated with the operation of three-way valves controlling the bearing water source for the safeguards cooling water pumps that result in shiftly change-outs of seal water filters once a shift on October 18, 2004; and

- problems associated with leakage by the letdown and orifice isolation valves that cause the momentary lifting of letdown relief valves on October 18, 2004.

b. Findings

No findings of significance were identified.

.2 Cumulative Effects of OWAs

a. Inspection Scope

On October 20, 2004, the inspectors performed an in-office review of the cumulative effect of all identified OWAs to determine if there was a significant impact on plant risk or on the operators' ability to respond to a transient or an accident. The inspection effort completed one operator workaround inspection sample. The inspectors used the documents listed in the Attachment to evaluate the list of OWAs.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

Steam Generator Replacement (50001)

a. Inspection Scope

From August 30 through September 3, 2004, and October 4 through October 8, 2004, the inspectors reviewed the licensee's design changes associated with the replacement steam generator (RSG) project. The inspectors selected and reviewed samples of permanent and temporary plant modifications, design specifications, corrective actions, change requests, and design calculations and reports to confirm that the RSG and related modifications were in compliance with applicable codes and standards. The inspectors reviewed applicable documentation associated with SG lifting and rigging, including calculations supporting the polar crane engineered lifts. In addition, the inspectors verified that temporary supports were in-place as designed prior to installing the RSG lower assembly. Additional inspection was conducted and is described in Section 4OA5.1 of this report.

The records reviewed by the inspectors are identified in the attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Unit 1 Refueling Outage

a. Inspection Scope

The inspectors observed the licensee's performance during the Unit 1 refueling outage 1R23 conducted between October 1 and November 29, 2004. These inspection activities represent a continuation of an inspection commenced during the previous quarter and do not constitute a refueling outage inspection sample.

This inspection consisted of a in-office and in-plant review of outage activities performed by the licensee. The inspectors conducted in-office reviews of outage related documentation and in-plant observations of the following outage activities daily:

- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of reactor coolant system (RCS) instrumentation and compared channels and trains against one another;
- observe ongoing work activities and foreign material exclusion control; and
- reviewed of selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

Additionally, the inspectors performed in-plant observations of the following specific activities:

- walkdown of plant areas which are inaccessible during power operations for evidence of leakage and integrity of structures, systems, and components in accordance with IP 71111.20, Section 02.02 in the volume control tank room, the deborating demineralizer rooms, the 12 waste holdup tank room, and an aerated monitoring tank room;
- observed the reload of fuel into the reactor from the control room, containment, and the spent fuel pool areas;
- observed core inventory verification;
- observed the reduction of reactor vessel level to reduced inventory conditions and its subsequent refill;
- conducted an independent post outage containment close-out inspection;
- conducted reactor coolant system leakage inspections at normal operating pressure and temperature;
- observed the reactor start up from the control room;
- review reactor physics testing; and
- observed generator synchronization to the grid.

b. Findings

No findings of significance were identified.

.2 Unit 2 Forced Outage

a. Inspection Scope

Unit 2 was taken off line and shut down to mode 4 on November 17, 2004, for a TS required action following the discovery of leaks on two containment fan coil units. Both trains of containment cooling were declared inoperable. Unit 2 was returned to full power on November 20, 2004. During that period, inspectors conducted in-plant observation of the unit shutdown, steady state shutdown operation, and the unit start up. The inspectors compared the plant performance to the expected plant performance as provided in applicable procedures and completed a review of the containment closeout activities including the control of foreign materials used to repair the containment fan coil units.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted in-plant observations of the physical changes to the equipment and an in-office review of documentation associated with two temporary modifications completing two temporary modification inspection samples. As part of this inspection, the documents in the Attachment were utilized to evaluate the potential for an inspection finding.

The inspectors reviewed the following temporary modifications:

- temporary modification 4T177 associated with the scavenging and combustion air damper for the 12 diesel driven cooling water pump on October 18, 2004; and
- temporary modification 4T175 associated with the installation of supplemental air bottles to provided the required air capacity for pressurizer PORV operation under LTOP conditions on November 5, 2004.

The inspection activities included, but were not limited to, a review of design documents, safety screening documents, and USAR to determine that the temporary modification was consistent with modification documents, drawings and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified. The inspectors also reviewed the CAPs listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors reviewed Revisions 28, 29, 30, and 31 of the Prairie Island Nuclear Generating Plant Emergency Plan and changes made to its emergency action levels that reverted the emergency action levels back to its last approved revision. These were reviewed to determine whether the changes identified reduced the effectiveness of the licensee's emergency planning, pending on-site inspection of the implementation of these changes.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Mitigating Systems and Barrier Integrity

a. Inspection Scope

The inspectors reviewed the licensee submittals for four performance indicators for Prairie Island Units 1 and 2, completing four performance indicator verification inspection procedure samples. The inspectors used performance indicator guidance and definitions contained in Nuclear Energy Institute Document 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the performance indicator data. The inspectors' review included, but was not limited to, conditions and data from logs, licensee event reports, condition reports, and calculations for each performance indicator specified. The inspectors also reviewed the CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with corrective action procedures.

The licensee's reports of the following performance indicators were verified:

Unit 1

- Safety System Unavailability - emergency alternating current power system for the 4th quarter 2003 through the 3rd quarter 2004; and
- Reactor Coolant System Leakage for the 4th quarter 2003 through the 3rd quarter 2004.

Unit 2

- Safety System Unavailability - emergency alternating current power system for the 4th quarter 2003 through the 3rd quarter 2004; and
- Reactor Coolant System Leakage for the 4th quarter 2003 through the 3rd quarter 2004.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was given to ensure timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action program as a result of inspector observations are covered by the list of documents included in the Attachment.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Correction Associated with Troubleshooting of 121 Control Room Air Handler

a. Inspection Scope

The inspectors assessed the licensee's maintenance effectiveness associated with repetitive problems on 121 control room air handling unit on November 2, 2004. During that inspection, the inspectors identified potential performance deficiency associated with the cross cutting area of problem identification and resolution.

b. Findings

The inspectors concluded that the licensee's ineffective troubleshooting resulted in multiple failures to promptly identify and correct conditions adverse to quality and prevent recurrence of subsequent 121 CRAH failures. The licensee's failure to conduct troubleshooting activities in a comprehensive and systematic manner was not in accordance with procedural requirements, management expectations, and was a performance deficiency. A detailed evaluation of this finding of very low safety significance can be found in Section 1R12 of this report. The inspectors determined the finding to be an NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions.

.3 Problem Identification and Correction Associated with the Availability and Understanding of the Pressurizer PORV LTOP Function Design Basis

a. Inspection Scope

The inspectors reviewed the technical adequacy of OPR 000361, that documented the operability of the pressurizer PORV for the LTOP safety function following identified concerns associated with the capacity of the back up air accumulators on September 22, 2004. During that inspection, the inspectors identified potential performance deficiency associated with the cross cutting area of problem identification and resolution.

b. Findings

The inspectors determined that a performance deficiency existed with the problem identification and resolution actions taken by the licensee during development and review of OPR 000361. Specifically, the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to the determination that the function remained operable. The inspectors concluded that an adequate justification providing reasonable assurance that the LTOP function would be accomplished if required was not attainable without a clear and complete understanding of the system's design basis. A detailed evaluation of this finding of very low safety significance can be found in Section 1R15 of this report. The inspectors determined the finding to be an NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions."

.4 Problem Identification and Resolution Annual Sample Review - Unit 1 Temperature Reduction below Pressure Temperature Limits Report (PTLR) Limits

a. Inspection Scope

During the week ending October 22, 2004, the inspectors selected a corrective action program issue for detailed review completing one problem identification and resolution annual inspection sample. The inspectors selected an issue associated with the violation of the PTLR RCS minimum temperature limit during an RCS fill and vent evolution. This problem was originally identified by a Unit 2 Reactor Operator and entered into the corrective action program with CAP 027064 on December 6, 2002. This violation of the PTLR temperature limit resulted in a finding of very low safety significance documented in IR 05000282/2004003; 05000306/2004003.

In order to assess the effectiveness of the licensee efforts to correct the identified problem and prevent its recurrence, the inspectors conducted a review of the previously referenced CAP and all other corrective action program documents related to the violation. In addition, the inspectors reviewed the corrective actions listed in the licensee's RCE 000188 "U1 RCS Operation not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22." The inspectors verified that the licensees corrective actions listed in the RCE addressed the causes of the vent and were appropriately implemented and planned. The inspectors reviewed the following corrective actions:

- procedure guidance upgrades related to RCS fill and vent evolutions;
- upgrades to the corrective action program pre-screening process; and
- provide training to operations, regulatory affairs, and engineering.

A list of the documents reviewed is included in the Attachment.

b. Findings

No findings of significance were identified.

.5 Problem Identification and Resolution Annual Sample Review - Flange Bolt Thread Engagement

a. Inspection Scope

During the week ending December 17, 2004, the inspectors selected a corrective action program issue for detailed review completing one problem identification and resolution annual inspection sample. The inspectors selected an issue associated with the requirements for flange bolt thread engagement. Questionable thread engagement has been identified on safety-related components including the 22 SI pump suction flange (CAP 025410), diesel generator D2 (CAP 025425), and containment fan coil units (CA 005026).

In order to assess the effectiveness of the licensee efforts to correct the identified problem and prevent its recurrence, the inspectors conducted a review of the previously referenced CAPs and all other corrective action program documents related to them. The inspectors reviewed the following corrective actions:

- engineering inspection and calculation determined that thread engagement deficiencies that were identified will meet the design strength requirements;
- procedure changes added guidance on thread engagement adequacy; and
- WOs were initiated to correct thread engagement deficiencies.

b. Findings

No findings of significance were identified.

.6 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of licensee trending activities to verify that emerging adverse trends that could indicate the existence of a more significant safety issue were adequately identified, were entered into the licensee's corrective action program at an appropriate threshold, and that timely corrective actions were implemented. This inspection effort completed one semi-annual trending inspection sample. The effectiveness of the licensee trending activities were assessed by comparing trends identified by the licensee with those issues identified by the NRC during the conduct of routine plant status and baseline inspections. The inspectors performed the inspection by in-office review of licensee corrective action program and other reports, including the following:

- trend reports;
- performance indicators;
- equipment problem lists;

- rework lists;
- system health reports;
- maintenance rule reports;
- corrective action program document search by system (60 systems); and
- corrective action program document search by key word (11 key words).

The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA4 Cross-Cutting Findings

.1 A finding described in Section 1R12 of this report had, as its primary cause, a Problem Identification and Resolution deficiency because the ineffective troubleshooting resulted in a failure to promptly identify and correct conditions adverse to quality and prevent recurrence of 121 CRAH failures.

.2 A finding described in Section 1R15 of this report had, as its primary cause, a Problem Identification and Resolution deficiency because the licensee failed to recognize and correct a clear lack of understanding of the design basis for the 15 pressurizer PORV cycles required to complete the LTOP function for a postulated mass injection event prior to the determination that the function remained operable.

4OA5 Other Activities

.1 Steam Generator Replacement (IP 50001)

a. Inspection Scope

During the outage, Prairie Island Generating Nuclear Plant (PINGP) replaced both the 11 SG and 12 SG. As described in IP 50001, the inspectors verified that engineering evaluations and design changes associated with SG replacements were completed in conformance with requirements in the facility license, applicable codes and standards, license commitments, and regulations.

Inspection observations of lifting and rigging activities, preparations for these activities, and associated modifications is contained in sections 1R02 and 1R17 of this report.

The inspectors reviewed a significant sample size of both welding and non-destructive examination (NDE) qualifications of personnel. Additionally, the inspectors reviewed the qualifications and training records for the specific welds and associated NDE that were reviewed. A review of NDE qualifications for pre-service welds associated with the SGs was also conducted.

Samples of radiography performed in accordance with ASME Section III were also reviewed. Particular emphasis was placed on the 12 SG girth weld and the 11 SG crossover leg weld.

The inspectors reviewed pre-service NDE packages performed by Framatome and reviewed the qualifications of individuals performing the NDE. Baseline eddy current examinations were reviewed verifying appropriate examination of u-tubes with a Bobbin coil for full length examination of and with a rotating coil in the tubesheet and the inside tube (rows 1 and 2) u-bend area. Detections of u-tube flaws during the baseline examination were reviewed to ensure that they were properly dispositioned. The inspectors verified that flaws were within present TS requirements.

A sample of pre-service NDE for the SGs after site installation was also reviewed. The Pre-Service Ultrasonic Testing (UT) Examinations reviewed were portions of the licensee's baseline examinations for the SG welds.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Lower Head Penetration Nozzles (Temporary Instruction 2515/152, Revision 1)

a. Inspection Scope

The objective of Temporary Instruction (TI) 2515/152, Revision 1, "Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02)," is to support the review of the licensee's reactor pressure vessel (RPV) lower head inspection activities that are implemented in response to Bulletin 2003-02 (ADAMS Accession Number ML032320153), which was issued on August 21, 2003. The TI validates that a plant is meeting its inspection commitments using procedures, equipment, and personnel that have been demonstrated to be effective in detecting signs of leakage from the RPV lower head penetration nozzles and the detection of RPV head degradation. As an ancillary benefit, the TI promotes information gathering regarding the condition of the RPV lower head to help the NRC staff identify and shape possible future regulatory positions, generic communications, and rule making.

During the Unit 1 outage, the licensee performed a Bare Metal Visual Inspection of the lower head and penetrations. In order to allow personnel access to the lower head, the licensee removed a circular portion (approximately 5 feet in diameter) of insulation at the very bottom of the head. This allowed a 360 degree inspection around the circumference of the penetrations either visually, where the insulation was removed, or with a high resolution camera mounted on a pole. The camera was electronically tied into a monitor which was being observed by the examiners so that 360 degree coverage could be assured. All penetrations were examined on the remote monitor by VT-2 qualified examiners using a pre-approved procedure, WO 0309438, "Perform Bare Metal Visual on Bottom of Reactor Vessel," that had previously been demonstrated during the examination of the Unit 2 lower head. Additionally, the licensee recorded the inspection and documented the results of the inspection in a data sheet attached to the work order.

b. Summary:

The licensee did not identify any leaking RPV lower head penetration nozzles.

c. <u>Evaluation of Inspection Requirements</u>

In accordance with the reporting requirements contained within TI 2515/152, Revision 1, the inspectors evaluated and answered the following questions:

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

1. Performed by qualified and knowledgeable personnel?

   Yes. The inspectors verified that the examination was performed by Level II VT-2 qualified examiners. While qualifications were not demonstrated by mockup, the lead examiner had previously performed the lower head inspection successfully on Unit 2. Additionally, the inspector attended the pre-job brief which reviewed requirements and techniques for assuring 360 degree examination of the circumference of each penetration, and review of visual examples of positive indications of boric acid leakage.

2. Performed in accordance with demonstrated procedures?

   Yes. The inspectors verified that the Bare Metal Visual Examination was performed in accordance with WO 0309438, "Perform Bare Metal Visual on Bottom of Reactor Vessel." This same procedure and examination methodology was used to successfully examine the Unit 2 lower vessel head.

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

   The inspectors were able to conclude through both direct observation and review of documentation that the licensee was able to perform, via camera, a 360 degree examination of the circumference of each of the 36 penetrations on the lower RPV head. The licensee used their corrective action program (CE 006528) to disposition and resolve any deficiency found during the lower head inspection.

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

   The inspector directly observed that the licensee was able to identify pressure boundary leakage and/or RPV lower head corrosion. For a large number of the penetrations, this capability could be achieved through simple direct observation. In the cases where direct observation could not achieve 360 degree coverage of the circumference of the penetration, the capability was achieved through use of a high resolution camera. In the case of all penetrations; however, the high resolution camera was used to visually examine the entire circumference to ensure a high resolution examination of each penetration was performed.

5. Could small boric acid deposits representing RCS leakage, as described in the Bulletin 2003-02, be identified and characterized, if present by the visual examination method used?

   Yes. The inspector verified through direct observation that the inspection being conducted by the licensee could properly identify and characterize by visual examination small boric acid deposits representing RCS leakage, as described in Bulletin 2003-02.

6. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

   While a great deal of the penetrations could be examined directly by the VT-2 qualified examiners, and were visually observed by the examiners prior to conducting the formal recorded examination, the examination of record was performed using a high resolution camera. The camera was electronically tied into a monitor which was being observed by the examiners, so that 360 degree coverage could be assured.

7. How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?

   There was 360 degree coverage around all 36 penetrations.

8. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, deposits from any source, physical layout, viewing obstructions)? Did it appear that there are any boric acid deposits at the interface between the vessel and the penetrations?

   In order to allow personnel access to the lower head, the licensee removed a circular portion (approximately 5 feet in diameter) of insulation at the very bottom of the head. This allowed a 360 degree inspection around the circumference of the penetrations either visually, where the insulation was removed, or with a high resolution camera mounted on a pole. While some of the penetrations were still not completely visible by direct observation, these penetrations could still be fully observed (360 degrees) by the poll mounted camera by extending it underneath the remaining insulation.

   Overall, the physical condition of the lower head was fairly good. There were streaks of white translucent dried liquid streaks running down the bottom of the vessel head. The streaks impacted most of the penetrations; however, there was not enough volume to the majority of the deposits to recover samples that could be adequately tested for chemical composition. Analysis of these streaks is discussed in the answer to question 11 below. These streaks were attributed to cavity seal leakage several refueling outages ago. The cavity seals were modified using a new design for the last several outages. The new seals have not had the same leakage problems as the previous seals. There also were some small areas on the annulus of some penetrations that contained spots of rust.

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

   No material deficiencies were identified that required repair.

9. What, if any, impediments to effective examinations, for each of the applied non-destructive examination methods, were identified (e.g., insulation, instrumentation, nozzle distortion)?

   There were no impediments to effective examination.

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

    This question is not applicable, since there were no indications of boric acid leaks from pressure-retaining components. The licensee did identify streaks from cavity seal leakage that was no longer active.

11. Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared), what constituents were looked for (e.g., boron, lithium, specific isotopes), and what were the licensee's criteria for determining any boric acid deposits were not from RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?

    Two samples of the streaks attributed to cavity seal leakage were taken between penetrations. No short-lived isotopes were detected indicating that no active leaks existed. From chemical analysis, the licensee determined that the samples contained cobalt-60, cesium-137, and zinc-65. The zinc-65 was attributed to the Zinc primer which coats the outside vessel surface.

    Penetrations where the licensee felt that the stains contained enough "volume" to be able to be chemically sampled were swiped and tested for short-lived radioactive isotopes. The samples were also analyzed for pH, boron, and Lithium; however, quantification of the boron and lithium was not possible since the levels were so small.

12. Is the licensee planning to do any cleaning of the head?

    No major cleaning of the lower head was planned. Since the stains and rust spots on the penetrations were so small, and because of radiation dose concerns, the licensee did not clean the penetrations.

13. What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?

    The licensee concluded that no unacceptable conditions were found. As already stated, boric acid deposits were attributed to cavity seal leakage that occurred several refueling outages ago. The licensee determined this because of past leakage from the old seals, and because chemical samples taken of the deposits revealed no short lived isotopes.

d. Findings

No findings of significance were identified.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. J. Solymossy and other members of licensee management at the conclusion of the inspection on January 7, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Inservice Inspection (IP 71111.08), Steam Generator Replacement Inspection (50001), and TI 2515/152, Revision 1, with Mr. J. Solymossy on December 21, 2004.
- Emergency Preparedness inspection with Mr. S. Skoyen on December 28, 2004.
- Annual NRC Licensed Operator Requalification examination with Mr. W. Markham, Initial Licensed Operator Training Group Lead, on January 3, 2005, via telephone.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
T. Allen, Outage and Scheduling Manager
T. Bacon, Operations Training Supervisor
L. Clewett, Plant Manager
T. Downing, Engineering Supervisor
R. Graham, Director of Operations
S. Hanson, ISI Coordinator
D. Herling, Assistant Operations Manager
P. Huffman, Manager of Operations
J. Kivi, Licensing Engineer
J. Lash, Training Manager
W. Markham, Initial Licensed Operator Training Group Lead
S. McCall, Programs Engineering Manager
O. Nelson, Steam Generator Engineer
S. Northard, Business Support Manager
J. Payton, Emergency Planning Coordinator
K. Pederson, Reactor Vessel Program Engineer
A. Qualantone, Security Manager
S. Redner, Eddy Current Testing Program Manager
G. Salamon, Regulatory Affairs Manager
T. Silverberg, Site Engineering Director
S. Skoyen, Emergency Preparedness Manager
J. Solymossy, Site Vice President
T. Taylor, Performance Assessment Manager
M. Werner, Plant Manager
J. Wren, NDE Level III

Nuclear Regulatory Commission
R. Daley, Senior Reactor Engineer
J. Neurauter, Reactor Engineer
T. Bilik, Reactor Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000282/2004008-01; 05000306/2004008-01	NCV	Failure to promptly identify and correct conditions adverse to quality associated with multiple 121 CRAH failures.
05000282/2004008-02; 05000306/2004008-02	NCV	Failure to identify that important information associated with LTOP design basis was not included in operability evaluation.

Discussed

None.

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.

1RST Post-Maintenance and Surveillance Testing

Post-Maintenance Testing

11 Battery Charger

SP 1098; 11 Battery Refueling Outage Discharge Test; Revision 24
Load Test Results; dated October 5, 2004
BCT-2000 Battery Load Test Report; dated October 6, 2004

11 Containment Spray Pump

SP 1090A; 11 Containment Spray Pump Quarterly Test; Revision 6
WO 0301139; Replace 11 Containment Spray Pump Mechanical Seal

Motor Operated Valve 32074

WO 0309400; Packing Leak on 11 SI Reactor Vessel Injection Motor Operated Valve
SP 1137; Recirculation Mode Valve Functional Test; Revision 25

11 TDAFW Pump

PM 3132-1-11; 11 TDAFW Pump Refueling Inspection; Revision 44
WO 0408846; Correct Cause of Turbine Overspeed Trip Condition
CAP 039899; 11 TDAFW Pump Overspeed Trip Occurred During Preventive Maintenance Test of PM 3132-1-11

Surveillance Testing

SP 1092C

SP 1092C; SI Check Valve Test (Head Off), Part C: Accumulator Flow Path Verification; Revision 7
CAP 039585; 11 SI Pump Stopped Due To Discharge Pressure Fluctuations
CAP 039599; Inadvertent Dilution of Unit 1 RCS Boron

SP 1083

SP 1083; Unit 1 Integrated SI Test With a Simulated Loss of Offsite Power; Revision 29
CAP 039792; Alarm 47019-0103 Cleared With Valid Signal Still In
CAP 039809; Operator Challenges Experienced During SP 1083 Integrated SI Test on November 11, 2004
CAP 039811; Invalid Nuclear Steam Supply System Annunciators During SP 1083 Integrated SI Test
CAP 039812; No Health Physicist Present at Pre-Job Brief for SP 1083 Integrated SI Test
CAP 039819; Inverter Input Breakers Tripped During SP 1083

SP 1070

SP 1070; Reactor Coolant System Integrity Test; Revision 34
CAP 039895; ASME Section XI Relevant Leak On CV 31329 Has an Active Packing Leak
CE 006647; ASME Section XI Relevant Leak On CV 31329 Has an Active Packing Leak

SP 1750

SP 1750; Post Outage Containment Close-Out Inspection; Revision 27
CAP 039975; Item Not Identified or Evaluated in SP 1750

SP 1036

SP 1036; Turbine Overspeed Trip Exercise; Revision 25
1C1.2; Unit 1 Startup Procedure; Revision 34
1C1.3; Unit 1 Shutdown Procedure; Revision 54
Operations Logs for November 23, 2004
CAP 039985; SP 1037 Not Performed Per the Technical Requirements Manual Within 31 Day Frequency

SP 1001AA/2001AA

SP 1001AA; Daily Reactor Coolant System Leakage Test; Revision 42
SP 2001AA; Daily Reactor Coolant System Leakage Test; Revision 39
Operations Log Entries; November 3, 2004,through December 3, 2004

1R01 Adverse Weather

Periodic Test Procedure TP 1637; Winter Plant Operation; Revision 34
Operating Procedure C28.6; Condensate Storage Tank Freeze Protection System; Revision 11
System Prestart Checklist C28-11, CST Winter Operation; Revision 9
Operating Procedure C37.8; Screenhouse Safeguard Equipment Cooling; Revision 7
Operating Procedure C37.5; Screenhouse Normal Ventilation; Revision 7

1R02 Evaluation of Changes, Tests, or Experiments

10 CFR 50.59 Evaluation No. 1021; RSG - Reactor Coolant Loop Structural Evaluation; Revision 0
10 CFR 50.59 Evaluation No. 1026; Unit 1 Replacement Steam Generator - Stress and Fatigue Analysis Report; Revision 0
10 CFR 50.59 Evaluation No. 1027; Design Change 00SG02 - Unit 1 Replacement Steam Generators; Revision 0
10 CFR 50.59 Evaluation No. 1028; RSG - Main Steam Line Break Mass and Energy Release for Containment Response; Revision 0
10 CFR 50.59 Screening No. 1878; Design Change 03SG05 Revision 0 and Associated Calculations PI-P-100 Revision 2 and PI-P-101 Revision 1; Revision 0
10 CFR 50.59 Screening No. 1940; DCP 03SG03, Associated Calculations; Revision 0
10 CFR 50.59 Screening No. 1942; DCP 03SG03, Associated Documents; Revision 0
10 CFR 50.59 Screening No. 1954; Modification No. 03SG01 - RSG and Secondary Piping; Revision 1
10 CFR 50.59 Screening No. 1957; DCP 03PC01, SG Rigging Inside Containment; Revision 0
10 CFR 50.59 Screening No. 1958; DCP 03PC02, SG Rigging and Transport Outside Containment; Revision 0
10 CFR 50.59 Screening No. 1978; Calculations EE-G-DC-2841 Revision D, EE-G-DC-2842 Revision C, and EE-G-DC-2843 Revision B; Revision 1
10 CFR 50.59 Screening No. 2031; Modification 03SG04, Vendor Calculation 83A9890; Revision 1
10 CFR 50.59 Screening No. 2096; DCP 03SG06; Revision 0
10 CFR 50.59 Screening No. 2153; DCP 03PC01, ECR-002, Temporary Addition of Polar Crane Hydraulic Motors, Permanent Changes; Revision 1
10 CFR 50.59 Screening No. 2153; DCP 03PC01, ECR-053, Temporary Addition of Polar Crane Hydraulic Motors, Permanent Changes; Revision 2
10 CFR 50.59 Screening No. 2164; Framatome Calculation 32-5044588-00, NAD Calculation CF.P1.00.OPS.006, NAD Memo OC.P1.2004.009; Revision 0

1R04 Equipment Alignment

Diesel Generator D5

Integrated Checklist C1.1.20.7-9; D5 Diesel Generator Valve Status; Revision 10
Integrated Checklist C1.1.20.7-10; D5 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 7
Integrated Checklist C1.1.20.7-11; D5 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 4
Integrated Checklist C1.1.20.7-12; D5 Diesel Generator Circuit Breakers and Panel Switches; Revision 9
CAP 038868; D5 Generator Loaded Hour Meter Stopped During SP 2093

12 Cooling Water Strainer

Integrated Checklist C1.1.35-3; Cooling Water System; Revision 23

22 TDAFW Pump

System Prestart Checklist C28-18, 22 TDAFW Pump; Revision 5

1R05 Fire Protection

Plant Safety Procedure F5, Appendix A, Revision 15; Fire Strategies for Fire Areas 1, 3, 10, 12, 15, 16, 35, 36, 66, 92, and 127.
Plant Safety Procedure F5, Appendix F, Revision 19; Fire Hazard Analysis for Fire Areas; 1, 3, 10, 12, 15, 16, 35, 36, 66, 92, and 127.
NSPLMI-96001; Individual Plant Examination of External Events, Appendix B; Internal Fires Analysis; Revision 2
ENG-ME-094; Prairie Island Fire Hazards Analysis Combustible Loading Analysis, Table 9; Revision 3; Addendum 0
CAP 039142; Fire Extinguisher Not in Location in F5 Appendix A
CAP 039375; CV-3113, 121 Motor Driven Fire Pump to Screen Wash Header Valve Failed to Open

1R06 Flood Protection Measures (Internal)

PINGP Procedure H36; Plant Flooding; Revision 0
5AWI 8.9.0; Internal Flooding Drainage Control; Revision 1
CAP 039083; Potential Critical Drainage Path Obstruction

1R08 Inservice Inspection Activities

ANSI/ASME N45.2.6-1978; Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants; 1978
CAP 038571; 1R23 Reactor Vessel Closure Head Bare Metal Visual Exam Results; dated September 16, 2004
CAP 036802; Identify the Configuration of the Nozzles on the Main Steam Headers; dated May 20, 2004
CE005939; ASME XI/BACC Relevant Leak Discovered on CV-31450 During BACC Walkdown; dated September 13, 2004
CE005956; ASME XI and BACC Relevant Leak Discovered During BACC Walkdown; dated September 13, 2004
CE005943; BACC Relevant Leak on 1PT-729 During BACC Walkdown; dated September 13, 2004
NMC Letter; NRC Bulletin 2002-02: Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs - 15-Day Response; dated August 26, 2002
OE 024001; Assess NRC Information Notice 2003-02: Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion; dated January 21, 2003

OE 024034; Assess NRC RIS 2003-01, Examination of Dissimilar Metal Welds, Supplement 10 to Appendix VIII of Section XI of the ASME Code; dated January 22, 2003
OE 031894; Palo Verde U-2 Shutdown Due to Increased Primary to Secondary Leakage; dated April 16, 2004
Other (OTH) 008357; NRC Information Notice 2001-09; Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a PWR; dated March 28, 2002
Letter; Response to Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants; dated May 25, 1988
SP 1405; Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment; Revision 0
WO 0305297; SP 1403, Reactor Vessel Closure Head Bare Metal Visual Examination; dated September 16, 2004
WO 0406141; SP 1410 RV Head Effective Degradation Year Calculation; dated September 13, 2004

1R11 Licensed Operator Requalification Program

5AWI 3.15.0; Plant Operation; Revision 15
Training Procedure PITC [Prairie Island Training Center] 3.7; License Requalification Examination Development and Administration; Revision 15
CAP 040418; Revise Process to Provide Remediation for Subpar Simulator Performance

1R12 Maintenance Rule Implementation

Maintenance Rule a(1) Action Plan for the Control Room Special Ventilation System; Revision 1
CAP 036039; 121 Control Room Air Supply Fan Stopped
CAP 036556; 121 Control Room Air Handler Tripped
CAP 037294; Control Room Ventilation System Transitioned to Maintenance Rule a(1) Status

1R13 Maintenance Risk Assessments and Emergent Work Control

Simultaneous Unavailability of the 125 Service Air Compressor, Bus 150, D2 Diesel Generator, 122 Control Room Chiller, 22 Component Cooling Water Heat Exchanger, 22 and 24 Containment Fan Coil Units, Motor Operated Valve 32027, and Motor Operated Valve 32030

Operator Logs for October 15, 2004
Risk Assessment for October 15, 2004
NF-39216; Flow Diagram for Unit 1 and 2 Cooling Water; Sheet 1, Revision AH
NF-39217; Flow Diagram for Unit 2 Cooling Water; Sheets 1, Revision AF and Sheet 2, Revision V

Simultaneous Unavailability of the 121 and 122 Instrument Air Compressors, the 12 Motor-Driven Auxiliary Feedwater Pump, and Diesel Generator D2

Risk Assessment for Proposed Work for Week 4412B
Operator Logs for October 18, 2004
CAP 039346; 121 Instrument Air Compressor Cooling Water Valve Broke Off

Simultaneous Unavailability of the 22 and 23 Containment Fan Coil Units

Risk Assessment for Proposed Work for Week 4504B
Operator Logs for November 18, 2004
CAP 39881; Possible 23 Containment Fan Coil Unit Leakage
CAP 39912; Mode Change With 23 Containment Fan Coil Unit Inoperable
CAP 39917; Verification of No Leakage on Unit 1 Containment Fan Coil Units

Emergent Failure of the Bus 26 Load Sequencer

Risk Assessment for Proposed Work for Week 4505A
Operator Logs for November 22, 2004
CAP 039978; Bus 26 Sequencer Failure

Emergent Failure of the Bus 15 Sequencer on November 22, 2004

Risk Assessment for Proposed Work for Week 4505A
Operator Logs for November 22, 2004
CAP 039982; During Performance of SP 1094, Bus 15 Load Sequencer Test Failed Twice

Emergent Failure of the 121 Instrument Air Compressor

Operator Logs for November 24, 2004
Risk Assessment for Proposed Work for Week 4505A
CAP 040038; 121 Instrument Air Compressor Tripped on Low Oil Pressure

Emergent failure of the Unit 2 Volume Control Tank 2LT-141

Unit 2 Configuration Risk Assessment for December 1, 2004
Operator Log Entries; November 30, 2004
CAP 040045; Unit 2 VCT Level Channels Exceeded 5 percent Tolerance per SP 2001B
CAP 040052; Repeat Maintenance on 2LT-141, VCT Level Transmitter

The Simultaneous Unavailability of the 12 RHR Pump, the 11 Charging Pump, the 12 Containment Spray Pump, and Diesel Generator D2

Operator Logs for December 13, 2004
Unit 1 Configuration Risk Assessment for December 13, 2004

1R14 Nonroutine Evolutions

Partial Loss of Instrument Air

Operator Logs for October 18, 2004
Abnormal Operating Procedure C34 AOP1; Loss of Instrument Air; Revision 13

Unit 1 Heat Up and Start Up

1C1.2; Unit 1 Start Up Procedure; Revision 34
Operator Logs for November 15 and 16, 2004
CAP 039863 1R23 - Leakage from Instrument Port Conoseals
CAP 039864; D7 Versus Westinghouse Assembly Specifications for Conoseals

Unit 2 TS Required Shutdown

Operator Logs for November 17, 2004
C35 AOP4;Cooling Water Leak In Containment; Revision 11
Operating Procedure 2C1.3; Unit 2 Shutdown; Revision 53
Operating Procedure 2C1.4; Unit 2 Power Operation; Revision 34
CAP 039881; Possible 23 Containment Fan Cooling Unit Leakage
CAP 039923; Unplanned Limiting Condition for Operation - 22 Containment Fan Cooling Unit

1R15 Operability Evaluations

LTOP Function of the Pressurizer PORVs

ENG-ME-537; Analysis of Pressurizer PORV Operation for LTOP; Revision 0
License Amendment Request Dated August 4, 1978; Low Temperature Overpressure Protection System
Operations Committee Meeting Minutes 2815; September 8, 2004
CAP 026839; If Desired Seat Load is Set on the Pressurizer PORVs, Then the Air Accumulator May Be Small
CAP 039539; Westinghouse Analysis Reveals Higher Required Number of PORV Strokes for LTOP
CE 006462; Westinghouse Analysis Reveals Higher Required Number of PORV Strokes for LTOP

Component Cooling Water Relief Valves

CAP 037533; Justification for Testing of CC-37-14 in Refueling Outage
OPR 000505; Justification for Testing of CC-37-14 in Refueling Outage

Air Operated Valve CV-31252

CAP 039657; CV-31252 Was Not Tested After Maintenance Was Performed
WO 0306643; Preventive Maintenance 31252-2, 11 Excess Letdown Heat Exchanger Component Cooling Water Air Operated Valve Overhaul
General Maintenance Procedure MAS-038; Masoneilan Air Operated Valve Type 38 Actuators; Revision 0
SP 1155A; Component Cooling Water System Quarterly Test Train A; Revision 7

Containment Spray

CAP 039792; Alarm 47019-0103 Cleared With Valid Signal Still In
OPR 000114; Containment Spray System Operability
SP 1083 Unit 1 Integrated SI Test With a Simulated Loss of Offsite Power
Drawings X-HIAW-1- 992, X-HIAW-1- 994, and X-HIAW-1- 1000; Containment Spray Logic

1R16 OWAs

Cooling Water Three-Way Valves and Lubricating Water Filter

CAP 036940; Replacement of CL Pump Seal Filters Should Be Considered an OWA
Prairie Island Operator Workarounds List; last updated October 18, 2004

Leakage Past Letdown Isolation Valves Lifting Letdown Relief Valves

Prairie Island Operator Workarounds List; last updated October 18, 2004
CAP 036983; 2VC-26-1 Lifted During Excess Letdown Operation
CAP 037135; Leakby of Unit 2 Chemical and Volume Control System Isolation Valves Results in a Three to Five Gallon Per Minute Reactor Coolant System Leak and Relief Lift
CAP 039373; 21 D5 Fuel Oil Transfer Pump Has Lost Its Prime Three Times Since April
Crew Meeting Review of Noteworthy Event/Near Miss/Change; dated June 24, 2004

Cumulative Effect Review

Operator Workaround Aggregate Impact Assessment

1R17 Permanent Plant Modifications

Calculation 0010000363-NL02-W-010; Mammoet - Lifting Beam; Revision 5S
Calculation 0010000363-NL02-W-017; Mammoet - OHTS [outside hatch transfer system] Bearing Loads; Revision 5
Calculation 32-5017262-02; Prairie Island LTOP; Revision 2
Calculation 32-5018728-01; Prairie Island RSG Natural Circulation Decay Heat Removal; Revision 1
Calculation 32-5044588-00; Prairie Island Evaluation of the PP7 Interlock on Natural Circulation from 20 Percent Power; Revision 0

Calculation 34191-CALC-C-004; RCS Temporary Supports; Revision 2
Calculation 34191-CALC-C-014; Qualification of Soil Bearing, Buried Pipes and Foundation for SG Rigging Loads; Revision 3
Calculation 34191-CALC-C-016; Qualification of In-Containment Structures for HTS [hatch transfer system] Loading; Revision 2
Calculation 34191-CALC-C-017; Evaluation of Polar Crane Ring Girder for Engineered Lift During the Unit 1 RSG Project; Revision 0
Calculation 34191-CALC-C-018; Design of OSG [original steam generator] "Top Hat" and Lifting Lugs; Revision 2
Calculation 34191-CALC-C-019; Load Qualification of Original Steam Generator Steam Drum Lifting Lugs; Revision 1
Calculation 34191-CALC-C-020; Boom Drop Analysis for Demag CC 2600 Crane Outside Unit 1 Equipment Hatch; Revision 2
Calculation 34191-CALC-—002; Determination of Weight and Center of Gravity for OSG Steam Generator Components; Revision 1
Calculation 83A9891; Prairie Island Type W-9 Nozzle Dams; Revision 0
Calculation C09915.40; Whiting Corporation - 230/20 Ton Polar Crane - Evaluation of Critical Load Carrying Crane Components for a 250 Ton Lifted Load and Class "A" Service Per CMAA 70 (2000) and ASME B30.2 (2001); Revision 1
Calculation ENG-ME-357; Appendix I - High Energy Line Breaks - Break Location Selection; Revision 1, including Addenda 1 and 2
Calculation ENG-ME-400; Stress Plots for High Energy Piping Systems; Revision 1, including Addendum 1
Calculation No. PI-P-100; Evaluation of Replacement Steam Generator Moisture Carryover Instrument Lines for SG11 and SG12; Revision 2
Calculation No. PI-P-101; Evaluation of Replacement Steam Generator External Recirculation Piping and Isolation Valves for RSG 11 and RSG 12; Revision 1
CA008402; Corrective Action - Lifting Lugs on Shield Building Hatch Blocks Are Not Stamped with Rated Load; dated February 6, 2004
CAP 023013; Nonconforming Condition on Framatome RSG NGV/291 for Two Tubesheet Holes; dated April 2, 2002
CAP 023236; Steam Generator Replacement Project Design/Modification Program Anomalies; dated April 23, 2002
CAP 035209; Lifting Lugs on Shield Building Hatch Blocks Are Not Stamped with Rated Load; dated February 5, 2004
CAP 035830; RELAP Is Not Approved as an Analysis as Described in the Calculations; dated March 18, 2004
CAP 036310; RSG Natural Circulation Analysis Goes to 10 Percent Power, Needs to Be Run to 17 Percent Power; dated April 21, 2004
CAP 036356; RSG Stress Analysis Used SRSS Instead of Direct Summation for Combination of Loss of Coolant Accident and Design Basis Earthquake Loads; dated April 23, 2004
CAP 037952; Unapproved Adhesive Sticker Applied to Stainless Steel Surface; dated August 16, 2004
CAP 039091; SG Replacement: During Upending of 11 RSGLA, Wire Rope on Mail Hoist Drum Was Misspooled; dated October 7, 2004
OTH 032167; Evaluate Permanent Use of New SG Drum Pressure Gauge or Initiate Design Change Package to Remove; dated April 28, 2004

Action Item No. 10157; Certified Design Specification Change; Revision 0
Action Item No. 13571; Certified Design Specification Change; Revision 0
Document No. 51-5016039-01; Engineering Information Record: Prairie Island LTOP; dated July 29, 2002
NSP Document No. B0105-NMC001; Welding Manual; Revision 0
Document No. BUCRPI/NGV 1745; Stress and Fatigue Analysis Report, Section 15: Small Nozzles; Revision C
Drawing SK-RECIRC-1; Replacement Steam Generator, External Recirculation Piping and Isolation Valve; Revision 1
Drawing SK-MC011; Replacement Steam Generator (SG11), Moisture Carryover Instrument Line Routing; Revision 1
ECN No. 03SG05-ECN-03; Change to 03SG05 - RSG New Connections - Design Description; Revision 0
ECR No. 111; Revision of Design Documents for a Polar Crane Lifted Load of 260 Tons; dated August 27, 2002
Letter from J. S. Poradzisz (Whiting Corporation) to R. Parlor (Framatome); Subject: Inspection Requirements for Planned Engineered Lifts; dated December 5, 2002
Letter from E. R. Toretta (Whiting Services) to SGT/Prairie Island; Subject: Engineered Lift on Prairie Island Reactor Crane, Serial Number 9915; dated September 30, 2004
Letter FRA 1095 NSP, Framatome ANP to NSP; Subject: Prairie Island RSG Unit 1, Certified Design Specification Change; dated February 13, 2004
Letter NSP1239FRA, NSP to Framatome ANP; Subject: CDS Change 13571 - Small Bore Nozzle Loads; dated April 14, 2004
M410 0004 001; Design Specification for Replacement Steam Generators Nozzle Dams; Revision 0
M530 0001 005; Certified Design Specification for Replacement Steam Generators; Revision 4
NCR No. 154; Exceeded Load Limit of Lifting Device; dated February 18, 2004
PCR 20042557B; Filling, Draining, and Recirculation 11 (12) SG Using the Recirc Rig; dated September 25, 2004
PINGP Units 1 and 2, Pressure and Temperature Limits Report; Revision 3
Procedure 5AWI 3.3.5; 50.59 Screenings; Revision 14
Procedure 5AWI 3.3.6; 50.59 Evaluations; Revision 6
TCN for WO 0310621; Fill and Drain New 11 SG After Installation; dated September 24, 2004
TCN for WO 0310622; Fill and Drain New 12 SG After Installation; dated September 24, 2004
WO 0309477; Install RSG 11 New Connections; dated July 26, 2004
WO 0309478; Install RSG 12 New Connections; dated July 26, 2004
WO 0310393; WP [Work Plan] 2570D, Prepare and Remove OSG 12 Lower Assembly
WO 0310410; WP 3040B, Install RSG 12 Lower Assembly
WO 0405540; Remove RSG11 Vault RTD Ambient Temperature Equipment; dated April 28, 2004
WO 0405541; Remove FW Anti-Stratification Test Equipment; dated April 28, 2004
Work Package 2570D, Attachment No. 48; Trolley Inspection for Planned Engineered Lift; dated September 29, 2004
Modification No. 03BM03; Containment Preparation - Structural/Mechanical; Revision 0
Modification No. 03PC01; Steam Generator Rigging Inside Containment; Revision 0

Modification No. 03PC02; Steam Generator Rigging and Transport Outside Containment; Revision 0
Modification No. 00SG02; Prairie Island Unit 1, Framatome Model 56/19 Replacement Steam Generators; Revision 0
Modification No. 03SG01; RSG and Secondary Piping; Revision 0
Modification No. 03SG02; Replacement Steam Generator Water Level; Revision 0
Modification No. 03SG03; RSG Insulation and Platform Modifications for RSG Clearance; Revision 0
Modification No. 03SG04; RSG Nozzle Dams; Revision 0
Modification No. 03SG05; RSG New Connections; Revision 0
Modification No. 03SG06; Unit 1 RSG Test Equipment Installation; Revision 0
Modification No. 03RC02; RCS Piping and SG Supports; Revision 0

1R20 Refueling and Other Outage Activities

SP 1177; Core Inventory Verification; Revision 11
SP 1750; Post Outage Containment Close-Out Inspection; Revision 27
Operating Procedure 1C1.2; Unit 1 Startup Procedure; Revision 34
Maintenance Procedure D30; Post Refueling Startup Testing; Revision 39

1R23 Temporary Modifications

Scavenging and Combustion Air Damper for the 12 Diesel-Driven Cooling Water Pump

Drawing NF-39603-1; Administrative Building Screenhouse and Control Room Flow Diagram; Revision AM
Drawing NF-39613-2; Screenhouse HVAC Sections; Revision L
QF-0540 (FP-E-MOD-03) Rev. 0; Temporary Modification Control Form for Temporary Modification 04T177
QF-0515A (FP-E-MOD-04) Rev. 1; Design Input Checklist (Part A); Modification 04T177
Calculation ENG-ME-178; DDCLP and MDCLP Room Temperatures with Degraded Combustion Air Damper; Calculation Revision 0, Addenda 3
PINGP 1229, Rev. 11; NMC Standard 10 CFR 50.59 Screening (Rev. 1), Part I; Number 2230
QF-0529 (FP-E-MOD-08) Rev. 0; Engineering Change Notice; ECN No. 04T177-01
WO 0406297; Repair 4 of 20 Damper Flaps Not Opening
Prairie Island Unit 2 Plant Status Report for October 12, 2004
CAP 039398; 122 Control Room Chiller Chemical Feeder Drain and Vent Valves Lack Fittings

PORV LTOP

Configuration Change Process Screening for 04T175; Pressurizer PORV Air Accumulator Supplementation; dated September 14, 2004
Temporary Modification Control Form for 04T175; Pressurizer PORV Air Accumulator Supplementation
10 CFR 50.59 Screening SES-2182; Pressurizer PORV Air Accumulator Supplementation; Revision 0

CAP 038549; Temporary Modification 03T157 Removed Without Approval
CAP 039765; 1R23 Air System for LTOP System Has a Air Leak

4OA1 Performance Indicator Verification

Performance Indicators - Mitigating Systems Unavailability, Unit 1; 4th Quarter 2003 through 3rd Quarter 2004
Performance Indicators - Mitigating Systems Unavailability, Unit 2; 4th Quarter 2003 through 3rd Quarter 2004

4OA2 Identification and Resolution of Problems

Unit 1 Temperature Reduction below PTLR Limits

CAP 02064; Transient RCS Temperatures of <86 Degrees Fahrenheit Observed During 1D8 RCP Runs
CE 001649; Transient RCS Temperatures of <86 Degrees Fahrenheit Observed During 1D8 RCP Runs
CA 003778; Transient RCS Temperatures of <86 Degrees Fahrenheit Observed During 1D8 RCP Runs
CAP 034273; CAP 027064 Closed with Incomplete Resolution of All Concerns
CE 004228; CAP 027064 Closed with Incomplete Resolution of All Concerns
OPR 000468; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
CAP 034715; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
CE 004417; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
CA 008125; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
CA 008390; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
RCE 000188; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
CA 008366; U1 RCS Operation Not Evaluated for Exceeding PTLR RCS Temperature Limit in 1R22
Thread Engagement
CAP 035690; CAP 025425 Was Closed Without Any Evidence of Completed Corrective Actions
CE 004858; CAP 025425 Was Closed Without Any Evidence of Completed Corrective Actions
CA 008676; Correct Short Bolt Issues Involving D1 Diesel Generator
CA 002408; 22 SI Pump Suction Flange Bolts Do Not Meet D63 Engagement Requirements
CAP 035689; Plant Configuration Control Anomalies
CA 008758; Plant Configuration Control Anomalies

Semi-Annual Problem Identification and Resolution Trend Review

Team-Track Hot Button and Key Word Search for Trends performed
December 13, 2004
Maintenance Rule Equipment Events for Previous Years as of October 11, 2004
System Monitoring and Reporting Tool
Top Ten Equipment List as of October 22, 2004
CAP 039373; 21 D5 Fuel Oil Transfer Pump Has Lost Its Prime 3 Times Since April
CAP 039700; Adverse Trend in Operations Performance

4OA5 Other Activities

Steam Generator Replacement (IP 50001)

Business Process Procedure H2; Boric Acid Corrosion Control Program; Revision 5
CAP 039260; RSG 12 SG ID [inside diameter] Weld and Surface Profile Observation in RCS Hot and Cold Legs; dated October 14, 2004
Framatome Document Identifier 51-5039649-00; Technical Summary of Steam Generator Eddy Current Examinations for Prairie Island Nuclear Generating Plant Unit 1, December 2003 - Pre-Service Baseline Inspection; dated February 13, 2004
FRA-ANP Contract Number: 2000002; Eddy Current Final Report, January 2004 - Pre-Service Inspection; dated March 1, 2004
Modification No. 03EX01; Containment Preparation - Electrical; Revision 0
SGT Non-Conformance Report No. 119 SG-11; RSG 11 and 12 Lower Assembly/RUBB Building PINGP As-Found Condition; dated September 3, 2004
SGT Non-Conformance Report No. 117; SG 12 Lower Assembly Girth Prep; dated August 20, 2004
SGT Non-Conformance Report No. 149; Cut #1 to SG11 Cold Leg (Crossover Leg 31 RC-2A); dated September 28, 2004
SGT Non-Conformance Report No. 150; SG 12 Lower Assembly Girth Weld Prep; dated September 28, 2004
SGT Non-Conformance Report No. 167; SG 12 Blowdown Piping Drawing X-HIAW-106-2492; dated October 4, 2004
SGT Non-Conformance Report No. 192; Fit-Up Gap of SG 12 Girth Weld; dated October 17, 2004
SGT Non-Conformance Report No. 193; Fit-Up Gap of SG11 Girth Weld; dated October 17, 2004
SWI NDE-UT-8; Ultrasonic Examination of RSG Feedwater Nozzle Inner Radius; Revision 0
SWI NDE-UT-3; Ultrasonic Examination of Ferritiec Vessels; Revision 0
UT Report 20020081; Tube Sheet/Head UT; dated November 28, 2002
WDC 3042B-001; RSG 12 Girth Weld; dated November 3, 2004
WDC 3065A-001; 29-RC-1A RCS Hot Leg Elbow to RSG Nozzle Safe End (SG11); dated November 6, 2004
WDC 3065A-002; 31-RC-2A RCS Crossover Leg Elbow to RSG Nozzle Safe End (SG12); dated November 6, 2004
WDC 3065-002-R1; 31-RC-2B RCS Crossover Leg Elbow to RSG Nozzle Safe End (SG12)

WO 0306235; SP 1405 Mid-Cycle Boric Acid Exam in CTMT; dated September 10, 2004
WO 0310231, Report No. 2004U090; Nozzle Inner Radius UT; dated November 8, 2004
WO 0310231, Report No. 2004U085; Top Head- Shell UT; dated November 8, 2004
WO 0310231, Report No. 2004U092; Nozzle - Shell UT; dated November 8, 2004
WO 0310316; UT of Valve to Pipe Weld, MS-19, RS-19-1; dated September 20, 2004
WP 3042B; SG11 Girth Weld; dated September 16, 2004

Reactor Pressure Vessel Lower Head Penetration Nozzles (Temporary Instruction 2515/152, Revision 1)

CE 006528; Document Unit 1 RPV Bottom Head Inspection and Evaluate As-Found Condition; dated November 3, 2004
WO 0309438; Unit 1 Reactor Vessel Bottom Head Bare Metal Visual; Revision 1

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADAMS	Agencywide Documents Access and Management System
ASME	American Society of Mechanical Engineers
AWI	Administrative Work Instruction
BACC	Boric Acid Corrosion Control
CA	Corrective Action
CAP	Corrective Action Program
CE	Condition Evaluation
CFR	Code of Federal Regulations
CRAH	Control Room Air Handler
CRSVS	Control Room Special Ventilation System
DRP	Division of Reactor Projects
gpm	gallons per minute
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LTOP	Low Temperature Overpressure Protection
IR	Inspection Report
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
MCC	Motor Control Center
MOLR	Motor Overload Relay
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NMC	Nuclear Management Company, LLC
NRC	U.S. Nuclear Regulatory Commission
OE	Operating Experience
OPR	Operability Recommendation
OSG	Original Steam Generator
OTH	Other
OWA	Operator Workaround
PE	Electrical Preventive Maintenance Procedure
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance Procedure
PORV	Power Operated Relief Valve
psig	pounds per square inch gauge
PTLR	Pressure Temperature Limits Report
RCE	Root Cause Evaluation
RCS	Reactor Coolant System
RPV	Reactor Pressure Vessel
RSG	Replacement Steam Generator
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SP	Surveillance Procedure
TDAFW	Turbine-Driven Auxiliary Feedwater
TI	Temporary Instruction

TS	Technical Specifications
USAR	Updated Safety Analysis Report
UT	Ultrasonic Testing
VT	Visual Test
WO	Work Order
WP	Work Plan