January 29, 2003

Mr. M. Nazar
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 50-282/02-09; 50-306/02-09

Dear Mr. Nazar:

On December 28, 2002, 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 13, 2003, with you and other members of your staff.

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

Based on the results of this inspection, the inspectors identified four issues of very low safety significance (Green). These were determined to involve violations of NRC requirements. However, because of the very low safety significance of the issues and because they were entered into your corrective action program, the NRC is treating the issues 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, 801 Warrenville Road, Lisle, IL 60532-4351; 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.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th

Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during 2002, and the remaining inspections are scheduled for completion in 2003. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Safety and Incident Response. For 2003, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and perform force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

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

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 5
Division of Reactor Projects

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

Enclosure: Inspection Report 50-282/02-09; 50-306/02-09
w/Attachment: Memorandum Regarding TI 2515/149

cc w/encl: Plant Manager, Prairie Island
R. Anderson, Executive Vice President
and Chief Nuclear Officer
Site Licensing Manager
Nuclear Asset Manager
Commissioner, Minnesota
Department of Health
State Liaison Officer, State of Wisconsin
Tribal Council, Prairie Island Indian Community
J. Silberg, Esquire
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P. Marker, Office of the Attorney General
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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:	50-282/02-09; 50-306/02-09
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 28, 2002
Inspectors:	J. Adams, Senior Resident Inspector S. Ray, Senior Resident Inspector, Braidwood S. Burgess, Senior Reactor Analyst D. Karjala, Resident Inspector D. Kimble, Resident Inspector, Monticello M. Mitchell, Radiation Specialist M. Holmberg, Reactor Inspector K. Poertner, Mechanical Engineer, NRR S. Sanders, Reactor Operations Engineer, NRR R. Jickling, Emergency Preparedness Analyst
Approved by:	Kenneth Riemer, Chief Branch 5 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000282/2002-009, 05000306/2002-009; Nuclear Management Company, LLC; on 10/1 -12/28/02, Prairie Island Nuclear Generating Plant, Units 1 & 2. Flood Protection Measures, Inservice Inspection Activities, and Event Followup. In addition, generic safety issue inspections in accordance with Temporary Instruction (TI) 2515/149, “Mitigating Systems Performance Index Pilot Verification,” were conducted.

This report covers a 3-month period of baseline inspection. The inspection was conducted by the resident inspectors, inspectors from the Region III office, and inspectors from the Office of Nuclear Reactor Regulation. Four 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. Inspection Findings

Cornerstone: Initiating Events

Green. A finding of very low safety significance was identified for the existence of prohibited loose materials in the safety-related cooling water pump rooms on three separate occasions. The materials were specifically prohibited due to the potential for the loose materials to obstruct required critical drainage paths from these areas adversely affecting measures for internal flood protection.

This finding is more than minor because it was associated with two of the cornerstone attributes, affected the initiating events cornerstone objective, and was repetitive. However, it was of very low safety significance because it did not contribute to the likelihood of a primary or secondary system loss of coolant accident, did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and did not increase the likelihood of a fire or internal/external flood. The finding was determined to be a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion V. (Section 1R06)

Cornerstone: Barrier Integrity

Green. The inspectors identified a finding of very low safety significance regarding inadequate instructions in three procedures used to conduct ultrasonic examination of plant components. Specifically, the licensee had not included the mode of ultrasonic wave propagation for the material under examination in these procedures.

The finding was more than minor because, if left uncorrected, it could have adversely affected the licensee’s ability to perform an adequate inspection of safety-related components, including the reactor vessel. However, it was of very low safety significance because the licensee confirmed that appropriate ultrasonic examinations had been conducted during past examinations. This finding was determined to be an NCV of 10 CFR 50.55a(g)(4). (Section 1R08)

Green. The inspectors identified a finding of very low safety significance regarding failure to conduct a periodic technical review of an ultrasonic examination procedure used to detect cracks in steam generator and main steam nozzle inner radii.

The finding was more than minor because, if left uncorrected, it could have resulted in failure to incorporate the appropriate technical requirements into the procedure and consequently led to an ineffective examination of plant components. The finding was of very low safety significance because the appropriate technical review was completed and only one technical error was identified which impacted the technical adequacy of the procedure. This finding was determined to be an NCV of 10 CFR Part 50, Appendix B, Criterion V. (Section 1R08)

Cornerstone: Emergency Preparedness

Green. On November 3, 2002, the licensee failed to classify and declare an Unusual Event in accordance with emergency plan implementing procedures following receipt of a seismic event annunciator in the control room and after confirmation with an offsite agency of the occurrence of an earthquake in Alaska.

The failure to declare an Unusual Event is associated with a risk significant planning standard and determined to be of very low safety significance using Manual Chapter 0609, Appendix B, "Emergency Preparedness Significance Determination Process," Sheet 2. The finding was determined to be an NCV of 10 CFR 50.54(q), 50.47(b)(4), and Sections IV.B and IV.D.3 of Appendix E of 10 CFR Part 50. (Section 4OA3)

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

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

REPORT DETAILS

Summary of Plant Status

Unit 1 was operated at or near full power until the unit was shut down for a refueling outage on November 15, 2002. Unit 1 was made critical for physics testing on December 5, and the unit was placed online on December 6. Unit 1 reached full power on December 9, and operated at or near full power for the remainder of the inspection period.

Unit 2 was operated at or near full power for the entire inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

During the week of November 3, 2002, the inspectors conducted plant walkdowns and document reviews to verify that the risk significant systems were adequately protected against impending cold weather. The inspectors concentrated on the safety-related cooling water (CL) pumps, safeguards traveling screens, nonsafety-related CL pumps, and external circulating water deicing equipment. The inspectors used the licensee checklists and procedures listed at the end of this inspection report to verify that the systems were lined up as required. In addition, the inspectors reviewed the Corrective Action Program (CAP) Action Requests (ARs) and work orders (WOs) listed at the end of this report to verify that the licensee had entered problems identified with cold weather operations into the corrective action system and was taking the appropriate compensatory actions.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial walkdowns of accessible portions of the following trains of risk-significant mitigating systems while the trains were of increased importance due to the redundant trains or other related equipment being unavailable:

- 12 safety-related diesel-driven cooling water (DDCL) pump during the unavailability of the 22 safety-related DDCL pump on October 22, 2002; and

- 21 component cooling water (CC) heat exchanger while the 22 CC heat exchanger was out-of-service for temperature control valve calibration on December 12.

The inspectors utilized the valve and electric breaker checklists listed at the end of this report 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 CAP ARs associated with the trains to verify that those documents did not reveal issues that could affect train function. The inspectors referred to the Technical Specifications (TSs) and Updated Safety Analysis Report (USAR) to determine the functional requirements of the systems. In addition, the inspectors reviewed the CAP ARs listed at the end of this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdowns

a. Inspection Scope

On November 1, 2002, the inspectors reviewed the alignment of the Unit 1 safety injection (SI) system outside of containment. On November 25, the inspectors reviewed the portion of the system inside containment. This system was selected because it was considered both safety-significant and risk-significant in the licensee’s probabilistic risk assessment. The inspection consisted of the following activities:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, and the USAR to identify proper system alignment;
- a review of outstanding or completed temporary and permanent modifications to the system;
- a review of control room operator log entries from February 1 through November 1, to identify potential system issues; and
- an electrical and mechanical walkdown of the system to verify proper alignment, component accessibility, availability, and current condition.

The inspectors also reviewed selected issues documented in CAP ARs, to determine if they had been properly addressed. Documents reviewed during this inspection are listed at the end of this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection Area Walkdowns (71111.05)

a. Inspection Scope

The inspectors conducted fire protection walkdown of fire area 86, intake screenhouse on October 9, 2002. During the walkdown, the inspectors focused on the availability and accessibility of fire protection equipment, the condition of fire fighting equipment, the control of transient combustibles, and the condition and operating status of installed fire barriers as described in fire hazards analysis and pre-fire plans. 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 (IPEEE). Additionally, the inspectors assessed the inspected area for the potential to impact equipment which could initiate a plant transient or that could impact the plant's ability to respond to a security event.

The inspectors reviewed the as-found condition of fire doors, dampers, penetration seals, fire detectors, sprinklers, fire hoses and extinguishers, comparing the as-found conditions to the configuration described in fire hazards analysis and pre-fire plans. During this review, the inspectors verified equipment was in its appropriate location, was available for immediate use, and was not obstructed. The inspectors also verified that the as-found transient combustible loading was within the analyzed limits. The inspectors reviewed applicable CAP ARs listed at the end of this report to verify that the licensee was identifying fire protection issues at an appropriate threshold and entering them into their corrective action program.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On October 16, 2002, the inspectors reviewed and assessed protection measures for internal flooding events. The inspectors evaluated whether the licensee took appropriate precautions to mitigate the risk from internal flooding events. Specifically, the inspectors performed the following:

- reviewed the USAR and other selected design basis documents to identify those areas susceptible to internal flooding;
- reviewed the licensee's probabilistic risk analysis and associated flood protection reports to identify risk significant flood areas and protective features;
- reviewed abnormal and alarm response procedures associated with the diagnosis and mitigation of flooding events;
- performed a walkdown of the Units 1 and 2 safety-related DDCL pump rooms, the common safety-related motor-driven cooling water (MDCL) pump room, and the safeguards traveling screens room to evaluate whether appropriate flood protection controls were being maintained; and

- interviewed selected operating, engineering, and maintenance staff regarding internal flood protection controls.

In addition, the inspectors reviewed the corrective action program to verify that identified problems were being entered with the appropriate characterization and significance. The inspectors also reviewed the corrective actions for flood protection related issues documented in selected action requests.

b. Findings

Introduction

On three separate occasions during the inspection period, inspectors identified the existence of loose materials in the safety-related CL pump rooms. These materials were specifically prohibited due to their potential adverse affect on required critical drainage paths. The existence of these conditions resulted in a finding of very low safety significance (Green) and a Non-Cited Violation (NCV) of NRC requirements.

Discussion

No deficiencies with the required flood protection measures were identified on October 16. Subsequently, however, during routine plant walkdowns, the inspectors identified the existence of loose materials in the safety-related cooling water pump rooms that were specifically prohibited due to their potential adverse effect on required critical drainage paths: on October 28, the inspectors identified two oil absorbent pads in the 22 DDCL pump room; on November 6, the inspectors identified a temporary power cable routed through a critical drainage path in the 12 DDCL pump room; and on November 13, the inspectors identified a significant quantity of foreign material in the 121 MDCL pump room while the pump was aligned as a safety-related pump.

In each case listed above, the licensee failed to remove, properly control, or prevent the introduction of materials that could block critical drainage paths associated with operable safety-related CL pumps. Administrative Work Instruction 5AWI 8.9.0, Section 6.2.2, states “materials that could plug drainage paths be prevented from doing so by tethering or anchoring the material when required equipment within the area is operable.” The materials identified by inspectors on October 28 and on November 13 were not tethered or anchored and in both cases the associated safety-related CL pumps were considered operable.

In the November 6th case, Section 6.2.5 of 5AWI 8.9.0 states “ensure temporary or permanent changes that could impact drainage flow within any critical drainage area are in accordance with the plant’s internal flooding analysis.” The installation of the temporary power cable identified by the inspectors had not been evaluated with respect to the internal flooding analysis prior to its routing through the critical drainage area.

Analysis

The inspectors determined that this finding was more than minor. Inspection Manual Chapter (IMC) 0612, Appendix E, Section 4, provides a number of examples of minor procedural errors. Example “a” is similar to this case and indicates that a problem of this type is more than minor if repetitive. The inspectors identified this issue on three separate occasions within a 3-week period. The internal flood protection measures required in these areas were not new requirements; the problems were in areas routinely visited by operators; and the licensee missed opportunities to identify and correct the issues in each of the cases prior to identification by inspectors. Additionally, this finding was associated with two of the cornerstone attributes listed in IMC 0612, Appendix B, Section C and affected the initiating events cornerstone objective. For example, the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations was affected by the materials that were introduced into the safety-related CL pump rooms. Specifically, the design control and human performance attributes were affected because the introduced materials changed the physical conditions assumed in the internal flooding analysis. Therefore, for the time that these conditions existed it could not be shown that the safety-related CL pumps would have remained available during an internal flood. The loss of a safety-related cooling water pump or pumps during an internal flood could upset plant stability.

The inspectors determined that the finding could be evaluated in accordance with IMC 0609, “Significance Determination Process [SDP],” because the finding was associated with an increase in the likelihood of an initiating event. Using the Phase 1 screening, the inspectors determined that the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident, did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and did not increase the likelihood of a fire or internal/external flood. The inspectors determined the finding to be of very low safety significance (Green).

Enforcement

In part, 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” states that activities affecting quality shall be accomplished in accordance with instructions, procedures, or drawings. Contrary to the above, the licensee failed to implement the requirements specified in procedure 5AWI 8.9.0, Section 6. Since the licensee entered the conditions identified by the inspectors into their corrective action program with AR CAP 026010, AR CAP 026158, and AR CAP 026291, this violation is being treated as an NCV in accordance with VI.A.1 of the NRC’s Enforcement Policy (NCV 50-282/306/02-09-01).

1R07 Heat Sink Performance

a. Inspection Scope

On November 15, 2002, the inspectors conducted a walkdown of the data acquisition test equipment installed on the Unit 1 CC heat exchangers and observed the real-time data obtained during pre-test equipment functional tests.

The inspectors reviewed the Unit 1 CC heat exchanger test data obtained from the performance tests conducted on November 16. The inspectors compared the test results to the heat exchanger’s required performance specified in the CC design basis documents listed at the end of this report. The inspectors evaluated test data for indications of heat exchanger deficiencies that could mask degraded performance and other heat exchanger problems that would be indicative of potential common cause heat sink problems that potentially could increase plant risk.

The inspectors reviewed the licensee's performance with respect to the identification and resolution of problems associated with heat sink performance problems. The inspectors focused their evaluation on problems that could result in an initiating event or affect multiple heat exchangers in mitigating systems, thereby increasing risk. A list of corrective action documents reviewed by the inspectors has been included at the end of this report.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system (RCS) boundary and risk significant piping system boundaries, based on review of records and in-process observation of nondestructive examinations.

From November 18 through November 26, 2002, the inspectors observed:

- ultrasonic (UT) examination of an elbow-to-pipe weld W-3 and safe-end-to-elbow weld W-2 on the pressurizer safety relief line inside the Unit 1 containment;
- UT examination of a reducer-to-safe-end weld W-13 on the pressurizer spray line inside the Unit 1 containment;
- dye penetrant (PT) examination of pipe-to-elbow weld W-25 on the residual heat removal (RHR) pump loop B line inside the Unit 1 containment;
- PT examination of the pipe-to-elbow weld W-6 on RCS loop A inside the Unit 1 containment;
- PT examination of the nozzle-to-pipe weld W-12 on RCS crossover loop A inside the Unit 1 containment;
- acquisition and evaluation of eddy current (ET) data on the Unit 1 steam generators (SGs), which occurred in a service building outside the protected area;
- video taped visual examination of the secondary side inspection of SG 11 at the top of the tubesheet to locate potential loose parts, which occurred in a service building within the protected area; and
- in situ pressurization of two SG tubes inside the Unit 1 containment. The tubes tested were located in SG 11 at row 14, column 31, and row 11, column 37, and each contained a single axial ET indication located just above the top of the tubesheet.

From November 18 through November 26, 2002, the inspectors reviewed:

- repair and replacement records required by the American Society of Mechanical Engineers (ASME) Code for the performance of a preventative weld buildup on the control rod drive intermediate canopy seal weld and the replacement of the B loop pressurizer spray valve CV 31225; and
- nondestructive examination reports with Code recordable indications identified during previous UT and PT examinations.

The records reviewed and activities observed were evaluated for conformance with requirements in Section III, V, IX, and XI of the ASME Code.

The inspectors also reviewed a sample of inservice inspection related problems documented in the licensee’s corrective action program, to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements.

b. Findings

(1) Missed SG 12 and SG 21 Tubesheet-to-Head Weld UT Examinations

Introduction

On November 25, 2002, the inspectors identified an unresolved item (URI) associated with the licensee’s failure to perform a volumetric examination of the Unit 1 SG 12 and Unit 2 SG 21 tubesheet-to-head W-A welds during the 1999 and 2002 refueling outages, respectively. At the conclusion of this inspection, the inspectors could not determine the risk of this finding because the licensee had not yet completed re-examination of these welds to determine the size and significance of weld flaws left in service.

Description

For Unit 1, the licensee identified a flaw during the 1999 UT examination of the SG 11 tubesheet-to-head weld W-A that exceeded Code acceptance standards of Table IWB-3410-1. The licensee accepted the flaw based on an analysis derived in Westinghouse document WCAP 14166, “Handbook on Flaw Evaluation for Prairie Island Units 1 and 2 Steam Generators and Pressurizer.” However, the licensee did not examine the SG 12 W-A weld during this outage as required by paragraph IWB-2430 of Section XI of the 1989 Edition, no Addenda, of the ASME Code. For the SG 12 W-A weld, the licensee had not completed a UT examination since 1998. The licensee entered the failure to perform the SG 12 W-A weld examination into the corrective action system (CAP 026715) and no immediate operability evaluation was required because Unit 1 was in cold shutdown. The licensee subsequently initiated actions to perform examinations of the Unit 1 SG 11 and SG 12 W-A welds during the current refueling outage.

During the extent of condition review, the licensee identified that a similar condition also existed for the Unit 2 SG W-A welds. When the licensee examined the SG 22 weld W-A in February of 2002, 14 flaws were identified which exceeded Code acceptance standards of Table IWB-3410-1. The licensee applied a weld flaw analysis derived in

WCAP 14166 to accept these flaws for continued service. However, the licensee did not expand the scope of the inspection to include UT examination of the SG 21 weld W-A. The licensee last performed a UT examination of one-third of the SG 21 weld W-A in May of 2000. The licensee entered the failure to perform the SG 12 W-A weld examination into the corrective action system (CAP 026755), considered that the SG 21 weld W-A was operable, and was evaluating the need to seek NRC approval for Code relief to allow deferral of this weld examination until the next refueling outage in the fall of 2003. In operability recommendation (OPR) 000360, the licensee concluded that the SG 21 W-A weld was operable because only Code acceptable indications were identified during the previous two UT examinations conducted in 1997 and 2000, which provided assurance that no structurally significant flaws could exist. The inspectors noted that the licensee had last performed a full inspection of this weld in 1993 and had not established a basis for their conclusion that no structurally significant flaws were present. The licensee subsequently revised OPR 000360 and included a technical evaluation of the potential inservice flaw sizes based on a methodology established in WCAP 14166. The licensee's revised OPR considered embedded flaw growth using a series of loading transients with the maximum applied stress intensity factor for the maximum size flaw detected. Based on this methodology, the licensee concluded that the indications identified during the 2000 refueling outage were acceptable for 10 years of service without further inspection and SG 21 was operable. The inspectors noted that the application of WCAP 14166 to inservice flaws in SG W-A welds had been accepted by the NRC for previous flaw evaluations, however, not as a basis to allow deferring the required Code examinations.

The licensee was in the third Code interval and was committed to the requirements of Section XI, 1989 Edition, no Addenda, of the ASME Code for these inservice examinations. Specifically, the SG head-to-tubesheet W-A welds were required to be volumetrically examined once per Code interval (10 years) in accordance with the Table IWB-2500 Category B.2.40. Section XI, IWB-2430 required "Examinations performed in accordance with Table IWB-2500-1 that reveal indications exceeding the acceptance standards of Table IWB-3410-1 shall be extended to include additional examinations at this outage. The additional examinations shall include the remaining welds, areas, or parts included in the inspection item listing..." This statement required the licensee to take prompt (at this outage) actions to determine the extent of potential degradation when inservice weld flaws were identified which exceed Code limits. Therefore, the inspectors were concerned that the licensee's decision to not examine SG 12 and SG 21 W-A welds during the 1999 and 2002 refueling outages could have potentially allowed weld flaws of unacceptable size to remain in service.

The licensee staff discussed their decision to not apply the Section XI, IWB-2430 requirements to expand the scope of weld examinations for these SG W-A welds. The licensee staff had applied a successive examination schedule discussed in Section XI, IWB-2420 to the SG 11 and SG 22 W-A welds because flaws were identified that required an analysis to leave in service. The licensee staff then excluded application of IWB-2430 requirements to expand the extent of weld examinations to SG 12 and SG 21 W-A welds, because SG 11 and SG 22 W-A welds were in a successive examination schedule. The licensee staff had interpreted the Section XI, IWB-2430 statement "examinations performed in accordance with Table IWB-2500-1," to allow excluding expansion of weld examinations for "new" weld flaws identified during successive examinations performed under IWB-2420. Section XI, IWB-2420(b) required "If flaw indications or relevant conditions are evaluated in accordance with IWB-3132.4 or IWB-3142.4, respectively, and the component qualifies as acceptable for continued service, the areas containing such flaw indications or relevant conditions shall be reexamined during the next three inspection periods listed in the schedules of inspection programs of IWB 2410." For SG 11 and SG 22 the licensee was performing these successive examinations beginning in 1994 for SG 11 and 1989 for SG 22 after identification of subsurface flaws which exceeded acceptable sizes as identified in Table IWB-3410-1. The licensee staff believed that these subsurface flaw indications which exceeded Code acceptance criteria, were likely fabrication-related weld defects (e.g., slag, inclusions or weld porosity), vice service-induced. However, the licensee's manual UT examination methods were not sufficient to confirm the flaw locations or to determine changes in flaw size (e.g., flaws indications sometimes got smaller in subsequent examinations). Therefore, the licensee staff had considered each flaw identified in the SG W-A welds that exceeded Code acceptance criteria during these examinations to be a "new" flaw.

The inspectors requested the licensee provide a technical basis to support their application of Code requirements to not expand the scope of the SG W-A weld examinations. At the conclusion of the inspection, the licensee staff did not have a documented technical basis, nor an NRC-endorsed Code Case, which supported their potentially nonconservative application of Code requirements.

Analysis

The licensee performance deficiency associated with this finding was a failure to follow the ASME Code examination expansion requirements to volumetrically examine weld W-A on SG 12 and SG 21 during the 1999 and 2002 refueling outages respectively. The inspectors reviewed this issue against the guidance contained in Appendix B, "Issue Dispositioning Screening," of IMC 0612, "Power Reactor Inspection Reports." In particular, the inspectors compared this finding to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612 to determine whether the finding was minor. Following that review, the inspectors concluded that the guidance in Appendix E was not applicable for the specific finding since no examples were provided which involved failure to perform inservice examinations. As a result, the inspectors compared this performance deficiency to the minor questions contained in Section C, "Minor Questions," to Appendix B of IMC 0612. The inspectors concluded that the issue was more than minor because the finding, if left uncorrected, could become a more significant safety concern. Specifically, the licensee's failure to volumetrically examine weld W-A in SG 12 and SG 21 could have resulted in plant operation with unacceptable weld flaws that challenged the reactor coolant pressure boundary integrity.

As a result, the inspectors reviewed this issue in accordance with IMC 0609, "Significance Determination Process." The inspectors conducted this review utilizing the "SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems] and B [Barrier Integrity] Cornerstones." The inspectors determined that this issue potentially affected the NRC's Barrier Integrity Cornerstone. However, the inspectors could not evaluate the significance of this issue until the licensee completed UT examination of SG 12 weld W-A and SG 21 weld W-A to determined the size and significance of weld flaws left in service.

Enforcement

Requirements of 10 CFR 50.55a(g)(4) are, in part, that throughout the service life of a pressurized water-cooled nuclear power facility, components must meet the requirements set forth in the ASME Code, Section XI. Section XI, IWB-2430 required "Examinations performed in accordance with Table IWB-2500-1 that reveal indications exceeding the acceptance standards of Table IWB-3410-1 shall be extended to include additional examinations at this outage. The additional examinations shall include the remaining welds, areas, or parts included in the inspection item listing..."

Contrary to these requirements, on May 22, 1999, the licensee performed an examination as described in Table IWB-2500-1 (Code item B.2.40) for Unit 1 SG 11 weld W-A that revealed an indication which exceeded the acceptance standards of Table IWB-3410-1 and failed to include additional examinations of the remaining Code item B.2.40 welds of Table IWB-2500-1 during the 1999 outage. Specifically, the licensee failed to perform a volumetric examination of weld W-A on SG 12 during the 1999 outage and this weld had not received a volumetric inspection since 1998.

Contrary to these requirements, on February 15, 2002, the licensee performed an examination as described in Table IWB-2500-1 (Code item B.2.40) for Unit 2 SG-22 weld W-A that revealed 14 indications which exceeded the acceptance standards of Table IWB-3410-1 and failed to include additional examinations of the remaining Code Item B.2.40 welds of Table IWB-2500-1 during the 2002 Unit 2 refueling outage. Specifically, the licensee failed to perform a volumetric examination of weld W-A on SG 21 during the February 2002 outage and this weld had not received a volumetric inspection since May 2000.

Because the significance of this finding is not yet known, it is considered an Unresolved Item (URI 50-282/306/02-09-02) pending completion of a UT examination of weld W-A on SG 12 and weld W-A on SG 21.

(2) Lack of ASME Code Requirement in Ultrasonic Examination Procedures

Introduction

The inspectors identified a finding of very low significance (Green) and an associated NCV of 10 CFR 50.55a(g)(4) related to inadequate instructions in three procedures used to conduct ultrasonic examination of plant components.

Description

On November 20, 2002, the inspectors identified three procedures used for conducting UT examinations of ASME Code components, that lacked a Code requirement to specify the mode of wave propagation in the material. Specifically, procedures ISI-UT-3, "Ultrasonic Examination of Ferritic Vessels," Revision 10, ISI-UT-3A, "Ultrasonic Examination of Reactor Vessel Welds," Revision 8, and

ISI-UT-5E, “Ultrasonic Examination of Steam Generator Primary and Main Steam Nozzle Inner Radii,” Revision 1, lacked instructions which described the mode of wave propagation in the material under examination. The inspectors were concerned that failure to include this Code requirement could result in the licensee staff selecting an incorrect UT transducer, which could result in an ineffective weld examination. For example, an L-wave transducer produces both a refracted shear wave and longitudinal wave within the material examined. These two sound waves enter the material at different angles and propagate at different speeds which could cause the licensee staff to misinterpret flaw signals or misinterpret the extent of weld examination coverage achieved.

<u>Analysis</u>

The licensee performance deficiency associated with this finding was failure to incorporate an ASME Code requirement to specify the mode of wave propagation into procedures ISI-UT-3, ISI-UT-3A and ISI-UT-5E. The inspectors reviewed this issue against the guidance contained in Appendix B, “Issue Dispositioning Screening,” of IMC 0612, “Power Reactor Inspection Reports.” In particular, the inspectors compared this finding to the findings identified in Appendix E, “Examples of Minor Issues,” of IMC 0612 to determine whether the finding was minor. The inspectors concluded that the guidance in Appendix E was not applicable for the specific finding since no examples were provided which involved procedure errors which could lead to ineffective weld examinations affecting the pressure boundary integrity. As a result, the inspectors compared this performance deficiency to the minor questions contained in Section C, “Minor Questions,” to Appendix B of IMC 0612. The inspectors concluded that the issue was more than minor because the finding, if left uncorrected, could become a more significant safety concern, in that it could have adversely affected the licensee’s ability to detect flaws in safety-related components, including the reactor vessel. The failure to specify the mode of wave propagation could have allowed the licensee inspection staff to select an L-wave transducer when a shear wave transducer was appropriate or vice versa. The use of an incorrect transducer could render the weld examination ineffective, in that unacceptable weld flaws could potentially go undetected. Based on review of past examination records, the licensee determined that improper transducers had not been used for previous UT examinations. The licensee subsequently initiated changes to the procedures to include the mode of wave propagation in the material under examination.

As a result, the inspectors reviewed this issue in accordance with IMC 0609 “Significance Determination Process,” utilizing the “SDP Phase 1 Screening Worksheet for IE, MS and B Cornerstones.” The inspectors determined that none of the above cornerstones were directly impacted by this finding. Therefore, the inspectors concluded that this issue was not suited for SDP analysis, in accordance with Section 0506.b(3) of IMC 0612. Because this issue had not resulted in an ineffective weld examination, the inspectors concluded that it was of very low risk significance (Green).

Enforcement

Requirements of 10 CFR 50.55a(g)(4) are, in part, that throughout the service life of a pressurized water-cooled nuclear power facility, components must meet the requirements set forth in ASME Code, Section XI. Section XI, Article I-2100 required "Ultrasonic examination of vessel welds greater than 2 inches thickness shall be conducted in accordance with Article 4 of Section V..." Section V, Article 4, T-423, "Written Procedure Requirements," required "Each procedure shall include at least the following information: ..(f) angles and mode(s) of wave propagation in the material."

Contrary to these requirements, on November 20, 2002, the inspectors identified that procedures ISI-UT-3, "Ultrasonic Examination of Ferritic Vessels," Revision 10, ISI-UT-3A, "Ultrasonic Examination of Reactor Vessel Welds," Revision 8, and ISI-UT-5E, "Ultrasonic Examination of Steam Generator Primary and Main Steam Nozzle Inner Radii," Revision 1, did not specify the mode(s) of wave propagation in the material. The failure to specify the mode(s) of wave propagation in the material in these procedures were examples where the requirements of 10 CFR 50.55a(g)(4) were not met and was a violation. However, because of the very low safety significance and because the issue was entered into the licensee's corrective action program (CAP 026513), it is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 50-282/306/02-09-03).

(3) Missed Technical Review for Ultrasonic Examination Procedure

Introduction

The inspectors identified a finding of very low significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," related to a failure to conduct a periodic technical review for an ultrasonic examination procedure used to detect cracks in SG and main steam nozzle inner radii.

Description

On November 20, 2002, the inspectors identified that the licensee had failed to perform a periodic review for technical adequacy of procedure ISI-UT-5E used to perform ultrasonic examination of SG and main steam nozzle inner radii. The licensee issued this procedure in 1997, and as of November 20, 2002, had not performed a review to confirm that it was up-to-date with current requirements and technically accurate. Further, the inspectors had discovered a technical error associated with the mode of wave propagation in this procedure as discussed in Section 1R08.b.(2) above, which could have affected the effectiveness of the UT examination. During the extent of condition review for this issue, the licensee staff identified 11 other non-destructive examination procedures associated with the erosion-corrosion control program (e.g., monitors pipe wall loss) that had not received this periodic review. The licensee personnel had failed to enter these procedures into the Document Review Database, which the licensee used to track implementation of the required procedure reviews.

Analysis

The licensee performance deficiency associated with this finding, was failure to perform a periodic review for technical adequacy of procedure ISI-UT-5E. The inspectors reviewed this issue against the guidance contained in Appendix B, "Issue Dispositioning Screening," of IMC 0612, "Power Reactor Inspection Reports." In particular, the inspectors compared this finding to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612 to determine whether the finding was minor. The inspectors concluded that the guidance in Appendix E was not applicable for the specific finding since no examples were provided which involved failure to conduct technical reviews of procedures which are used to confirm the integrity of the reactor coolant pressure boundary. As a result, the inspectors compared this performance deficiency to the minor questions contained in Section C, "Minor Questions," to Appendix B of IMC 0612. The inspectors concluded that the issue was more than minor because the finding, if left uncorrected, could become a more significant safety concern. Specifically, the inspectors were concerned that the failure to perform this review for procedure ISI-UT-5E could result in failure to incorporate the appropriate technical requirements and consequently lead to an ineffective examination of plant components. The licensee subsequently completed the reviews for procedure ISI-UT-5E (and the 11 others identified by the licensee) and did not identify any technical errors, other than the one technical error associated with mode(s) of wave propagation as discussed in Section 1R08.b.(2). As a result, the inspectors reviewed this issue in accordance with IMC 0609 "Significance Determination Process," utilizing the "SDP Phase 1 Screening Worksheet for IE, MS and B Cornerstones." The inspectors determined that none of the above cornerstones were directly impacted by this finding; therefore, this issue was not suited for SDP analysis in accordance with Section 0506.b(3) of IMC 0612. Because this issue had not resulted in ineffective examinations of plant components, the inspectors concluded that it was of very low risk significance (Green).

Enforcement

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," required, in part, that "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings." Procedure MMRN 1.1, "Reference Manual Policy and Administration," Revision 0 required that all procedures shall be reviewed and/or revised within a 36-month period. Contrary to these requirements, the inspectors identified that as of November 20, 2002, procedure ISI-UT-5E, "Ultrasonic Examination of Steam Generator Primary and Main Steam Nozzle Inner Radii" Revision 1, had not received a review/revision within the 36-month period following the initial procedure issue date of October 6, 1997. The failure to conduct a periodic review of this procedure for technical adequacy was an example of where the requirements of 10 CFR 50, Appendix B, Criterion V, were not met and was a violation. However, because of the very low safety significance and because the issue was entered into the licensee's corrective action program (CAP 026514 and CAP 026574), it is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 50-282/306/02-09-04).

1R11 Licensed Operator Requalification (71111.11)

.1 Written Examination and Operating Test Results

a. Inspection Scope

The inspectors reviewed the pass/fail results of individual written tests, operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during calendar year 2002.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Multiple Cooling Water Pump Bearing/Seal Water Failures

a. Inspection Scope

On October 19, 2002, the inspectors reviewed AR CAPs 023088, 024290, 024661, 024872, 025483, 025825, and 025866 that identified problems with safety-related CL pump bearing/seal water. The proper operation of CL pump bearing/seal water supports the operability of the safety-related CL pumps that provide several safety-significant maintenance rule functions.

The inspectors performed an in-office review of corrective action program documents associated with the bearing/seal water failures. The inspectors compared the licensee's maintenance documentation to the requirements contained in the administrative work instruction (AWI) procedures for the performance of nuclear maintenance, investigation, and troubleshooting. The documents reviewed are listed at the end of this report.

The inspectors reviewed the licensee's implementation of the maintenance rule for the repeat failures of the bearing/seal water by comparing their actions to the requirements contained in the Maintenance Rule, 10 CFR 50.65, and Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, NUMARC 93-01. The inspectors evaluated whether the safety-related CL pumps were scoped in accordance with the maintenance rule, and whether the performance problems associated with bearing/seal water constituted maintenance preventable functional failures.

b. Findings

No findings of significance were identified.

.2 Auxiliary Building Roof Leakage

a. Inspection Scope

On October 25, 2002, the inspectors evaluated the licensee's disposition of the problems documented in General Condition Report (GEN) 200202455 and AR CAP 024598. Both of these corrective action documents identified equipment failures caused by auxiliary building roof leakage. During the review of these problems, the inspectors evaluated the licensee's use of appropriate work practices, review of problems for common cause failures, Maintenance Rule scoping, Maintenance Rule classification, Maintenance Rule performance criteria, and the trending of key performance parameters. The inspectors compared the actions taken by the licensee in response to these problems to established maintenance, Maintenance Rule implementation procedures, and documents listed at the end of this report. In addition, the inspectors reviewed the corrective action program documents listed at the end of this report to verify that the licensee had entered problems identified with effectiveness of maintenance and the implementation of the Maintenance Rule into their corrective action program.

b. Findings

No findings of significance were identified.

.3 Resolution of External Circulating Water Intake Screen Bypass Gate Repeat Failures URI 50-282/306/02-08-02

a. Inspection Scope

On August 20, 2002, during a previous inspection, while investigating the repeat failures of the external circulating water intake screen bypass gates, the inspectors identified that the licensee had inappropriately classified the bypass gates as low safety significant components. Since the bypass gates were improperly classified, the licensee's performance criteria were also inappropriate and bypass gate failures were not properly evaluated for maintenance preventable functional failures. The inspectors determined that the inappropriate maintenance rule safety significance classification of the intake bypass gates was a Green Finding. The inspectors concluded that a violation determination could not be completed until appropriate performance criteria for the low safety significant standby safety significance classification were first established by the maintenance rule expert panel. The need to evaluate the finding for violations of NRC requirements was left as an Unresolved Item (URI 50-282/306/02-08-02).

During the current inspection, on November 29, the inspectors reviewed the licensee's new performance criteria for the bypass gates, (a)(1) evaluation of gate failures in the previous 2 years, and the Maintenance Rule Expert Panel minutes from November 27. The inspectors compared the changes to the guidance provided in NUMARC 93-01 and the requirements of the Maintenance Rule, 10 CFR 50.65.

b. Findings

The inspectors determined that the performance of the bypass gates had not exceeded (a)(2) performance criteria. URI 50-282/306/02-08-02 is closed. No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's management of plant risk during emergent maintenance activities and during activities where more than one risk significant system or train was unavailable. The activities were chosen based on their potential for increasing the probability of an initiating event or impacting the operation of safety significant mitigating equipment. The inspection was conducted to verify 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 reviewed daily configuration risk assessment records, observed shift turnover meetings, observed daily plant status meetings, and reviewed risk assessment documents listed at the end of this report to verify that the equipment configurations were properly listed, that protected equipment was identified and controlled, and that significant aspects of plant risk were communicated to the necessary personnel. The inspectors discussed daily and emergent risk assessments with risk assessment engineers and operators.

The inspectors reviewed the following emergent and planned maintenance activities associated with the simultaneous unavailability of the listed maintenance rule risk significant systems:

- on October 16, 2002, the simultaneous unavailability of the 22 turbine-driven auxiliary feedwater (AFW) pump, 124 air compressor, 121 intake bypass gate, and 121 screenwash pump;
- on October 21, the simultaneous unavailability of the 22 DDCL pump and the D2 emergency diesel generator;
- on October 28, the simultaneous unavailability of the 21 RHR pump and 123 instrument air compressor; and
- on November 4, the simultaneous unavailability of the 121 instrument air compressor, 121 screenwash pump, 121 bypass gate, D1 emergency diesel generator, 11 RHR pump discharge to 11 SI pump suction motor-operated valve MV 32206, and 11 AFW pump.

The inspectors reviewed several ARs to verify that problems associated with plant risk assessment were identified at an appropriate threshold, and that corrective actions commensurate with the significance of the issue were identified and implemented. A detailed list of the documents reviewed during this inspection is included at the end of the report.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-Routine Plant Evolutions and Events (71111.14)

.1 Licensee Response to a Seismic Alarm Received Following Alaskan Earthquake

a. Inspection Scope

On November 3, 2002, a seismic alarm was received in the control room. Operators entered Abnormal Operating Procedure AB-3, "Earthquakes." The inspectors reviewed the operators response to this unplanned event and compared their actions to the actions specified in annunciator response procedures, abnormal operating procedures, and the emergency plan implementing procedures.

b. Findings

The licensee entered AB-3 on receipt of the alarm and confirmed the occurrence of an earthquake in Alaska by contacting the National Earthquake Information Center in Boulder, Colorado. The control room seismic monitor energized, the Seismic Event annunciator was received, and magnetic tape recorder operation initiated. However, a failure of the seismic monitor chart paper recorder to produce a visible indication on its chart paper prevented the timely evaluation of the peak acceleration experienced during the event. Additionally, the failure of operators to follow the emergency plan implementing procedure for event classification prevented classification and declaration of the event. This finding is discussed in detail in Section 4OA3 of this report.

.2 Planned Non-Routine Evolution Observed During the Unit 1 Refueling Outage

a. Inspection Scope

The inspectors observed planned non-routine activities performed during the Unit 1 refueling outage. The inspectors reviewed operator performance and compared their actions to the specified actions contained in plant operating, annunciator response, and abnormal operating procedures. Among the significant activities the inspectors observed during the refueling outage were the unit shutdown, cooldown, and entry into RHR operations on November 16, 2002; RCS draindown activities and reactor vessel head removal on November 20; RCS operation at reduced inventory conditions for installation and removal of SG nozzle dams on November 18 and 27; RCS fill and venting; RCS heat up to normal operating temperature and pressure; reactor startup; and synchronization of the main generator to the grid from December 2 through December 5. The inspectors reviewed CAP ARs to verify that minor issues identified during the performance of these activities were identified and entered into the licensee's corrective action system for resolution.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions, selected action requests, and other corrective action process documents associated with risk significant components and systems for which operability was questioned. On October 8, 2002, the inspectors evaluated the licensee's assessment of operability for the Units 1 and 2 containment buildings after the most recent loss-of-coolant accident analysis revealed a post-accident containment temperature in excess of the temperature assumed in the containment fan cooling unit heat removal analysis. This condition was evaluated to determine whether the continued operability of the containment structure and the systems located inside the containment structure were justified. The inspectors compared the containment structure and systems design criteria in TSs and USAR to the operability evaluation to verify that the containment structure and systems would remain operable. The inspectors verified that compensatory measures identified in the operability evaluation were in place, functioned as intended, and were properly controlled. A detailed list of the documents reviewed during this inspection is included at the end of the report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Review of Selected Workarounds

a. Inspection Scope

On November 1, 2002, the inspectors reviewed OWAs associated with venting of SI pumps to mitigate possible gas intrusion. The venting activity required operators to stand on the respective SI pump. The inspectors verified that the functional capability of the system, human reliability in responding to an initiating event, or the ability of operators to implement abnormal or emergency operating procedures were not significantly affected. The inspectors reviewed the applicable sections of the USAR and TSs and discussed the OWAs with control room operators. The inspectors also reviewed operator logs to identify any potential conditions that should be considered OWAs. A detailed list of the documents reviewed during this inspection is included at the end of the report.

b. Findings

No findings of significance were identified.

.2 Cumulative Effects of OWAs

a. Inspection Scope

On December 12, 2002, the inspectors reviewed 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 inspectors used the documents listed at the end of this report to evaluate the list of OWAs. The inspectors discussed the list of current OWAs with the operations support manager.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

During the week ending November 16, 2002, the inspectors reviewed design change modification 02CL01. This modification provided a new normal source of bearing and shaft lubrication water from the well water system, while retaining the safety-related supply from the CL system on the 22 DDCL pump. The inspectors reviewed and compared the system's design basis, licensing basis, and performance capability to the installed modification in order to verify that the system performance had not been degraded by the installation of the modification. The inspectors also reviewed changes that the modification installation did not place the plant in an unsafe configuration.

The inspectors considered the design adequacy of the modification by performing a review of the modification's impact on the plant's material requirements and replacement components, response time, control signals, equipment protection, operation, failure modes, and other related process requirements.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed post-maintenance testing activities associated with maintenance on important mitigating, barrier integrity, and support systems to ensure that the testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. The inspectors reviewed the appropriate sections of the TSs, USAR, and maintenance documents to determine the systems' safety functions and the scope of the maintenance. In addition, the inspectors reviewed ARs to verify that minor deficiencies identified during these inspections were entered into the licensee's corrective action system. A detailed list of the documents reviewed during this inspection is included at the end of the report.

The inspectors observed and evaluated the post-maintenance activities for the following:

- 124 air compressor following 1000-hour preventive maintenance (PM) on October 17, 2002, WO 0206295;
- 22 DDCL pump following annual inspection and other maintenance activities on October 24, WO 025889;
- 11 SI pump following corrective and preventive maintenance on November 6, WO 0114563;
- 22 DDCL pump following PM on November 15, WO 0204494; and
- 22 DDCL pump following installation of a new source of bearing water on December 16, WO 0211272.

b. <u>Findings</u>

No findings of significance were identified.

1R20 <u>Refueling and Other Outage Activities</u> (71111.20)

a. <u>Inspection Scope</u>

The inspectors observed activities and/or reviewed documents associated with the Unit 1 refueling outage. The inspectors reviewed the outage plan and schedule in order to verify that the shutdown risk had been adequately evaluated in accordance with the licensee's shutdown safety assessment procedures. The inspectors routinely reviewed the licensee's shutdown risk assessments comparing the licensee's assessment to plant equipment configuration and procedural requirements for shutdown risk assessments. During this review, the inspectors also reviewed the capability of plant equipment to perform critical safety functions. The inspectors also observed portions of the fuel handling operations in containment, in the spent fuel pool, and in the control room. The inspectors verified that the licensee performed these activities in accordance with TSs and approved fuel handling procedures. The inspectors conducted a containment cleanliness inspection near the end of the outage to verify that no material remained in containment that could impair flow to the containment recirculation sump.

b. <u>Findings</u>

No findings of significance were identified.

1R22 <u>Surveillance Testing</u> (71111.22)

a. <u>Inspection Scope</u>

The inspectors observed selected surveillance tests and/or reviewed test data to verify that the equipment performance met surveillance procedure (SP) acceptance criteria. The inspectors verified that the tested equipment was capable of performing its intended safety functions as described in TSs and the USAR. The inspectors verified that the testing met the required TS frequency; that the tests were conducted in accordance with the applicable procedures; that operators met prerequisites and established the proper plant conditions; and that the results of the tests were properly reviewed and recorded.

In addition, the inspectors reviewed several ARs to verify that the licensee was identifying surveillance problems at an appropriate threshold, and that corrective actions commensurate with the significance of the issue were identified and implemented. A detailed list of the documents reviewed during this inspection is included at the end of the report.

The following tests were observed and/or evaluated:

- Unit 1 RCS Bolting Inspection, SP 1392, on November 16, 2002;
- Unit 2 Integrated Safety Injection Test with Simulated Loss of Offsite Power, SP 1083, on November 17;
- Safety Injection Check Valve Test (Head Off) Part B: Refueling Water Storage Tank (RWST) to RHR Flow Path Verification, SP 1092B, on November 20;
- SI Check Valve Test (Head Off) Part A: High Head SI Flow Path Verification, SP 1092A, on November 21;
- Core Inventory Verification, SP 1177, on November 25;
- D2 Diesel Generator Monthly Slow Start Test, SP 1305, and D2 Diesel Generator 18-Month 24-Hour Load Test, SP 1335, on November 25 - 26;
- Reactor Protection Logic Time Response Test, SP 1008, on December 2;
- Safety Injection Check Valve Test (Head On) Part D, SP 1092D, and Turbine Building Cooling Water Header Isolation SI Relays 1SI-12X and 1SI-22X Contact Verification Test, SP 1126, on December 2 - 3;
- Unit 1 Containment Coating Inspection, SP 1834, on December 4;
- Reactor Coolant System Integrity Test, SP 1070, on December 4; and
- Post-Outage Containment Close-Out Inspection, SP 1750, on December 5.

b. <u>Findings</u>

No findings of significance were identified.

1R23 <u>Temporary Plant Modifications</u> (71111.23)

.1 <u>Temporary Modification 02T131 Temporary Pipe Patch on a Pinhole Leak in Line 14-ZX-6</u>

a. <u>Inspection Scope</u>

On October 3, 2002, the inspectors reviewed Temporary Modification 02T131 that installed a temporary pipe patch on a pinhole leak in line 14-ZX-6, the cooling water supply line to Unit 1 and Unit 2 . The cooling water line itself was not considered a risk significant component; however, the location of the leak was in close proximity to a 480-volt motor control center (MCC) that provided power to risk significant mitigating system components. Due to the close proximity of the patch to the safety-related MCC, the inspectors considered this temporary modification appropriate for inspection since it could adversely affect the availability, reliability, or functional capability of risk significant mitigating system components powered from the MCC.

The inspectors reviewed the associated 10 CFR 50.59 safety evaluation screening, comparing it with system design basis requirements in the USAR. The inspectors discussed the installation of the pipe patch with design engineers and compared the use of the pipe patch temporary repair to Construction Code B-31.1 (1969) criteria.

b. Findings

No findings of significance were identified.

.2 Temporary Modification 02T147 Temporary Pipe Clamp on the Instrument Air Supply Header to the Unit 2 Containment

On October 22, 2002, an air leak was discovered on the 2-inch instrument air header that feeds the Unit 2 containment. The air leak was caused by degradation of a solder joint between supply piping and an adjacent elbow. The licensee installed a pipe clamp as a preventive measure to preclude separation of the pipe from the elbow if solder joint integrity were to further degrade.

On October 31, the inspectors reviewed Temporary Modification 02T147, which was used for installation of the clamp on the header. The inspectors reviewed the associated 10 CFR 50.59 safety evaluation screening, comparing it with system design basis requirements in the USAR. The inspectors discussed the installations of the pipe clamp with the system engineer and conducted a visual inspection of the pipe clamp installation to assess if its installation adversely affected availability, reliability, or functional capability of the instrument air supply to the Unit 2 containment.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector reviewed Revision 24 of the Prairie Island Plant’s Emergency Plan to determine whether changes identified reduced the effectiveness of the licensee’s emergency planning, pending onsite inspection of the implementation of these changes.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the licensee perform an emergency preparedness drill on October 23, 2002. The inspectors observed activities in the control room simulator. The inspectors also attended the post-drill facility critique for the control room simulator immediately following the drill and reviewed the final drill critique report. The inspectors focused on weaknesses and deficiencies in the drill performance and ensured that the licensee evaluators noted the same weaknesses and deficiencies and entered them into the corrective action program. The inspectors placed emphasis on observations regarding event classification, notifications, protective action recommendations, and site evacuation and accountability activities. As part of the inspection, the inspectors reviewed the drill package listed at the end of this report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns

a. Inspection Scope

The inspectors performed walkdowns of the radiologically controlled area (RCA) to verify the adequacy of radiological boundaries and postings. Specifically, the inspectors performed confirmatory radiation measurements in the Unit 1 containment and auxiliary and waste buildings to verify that radiologically significant work areas (high radiation areas (HRAs), radiation areas, and airborne radioactivity areas) were properly posted and controlled in accordance with 10 CFR Part 20 and the licensee's procedures. Additionally, the inspectors reviewed practices during the ongoing refueling outage for controlling access to contaminated areas and for posting and controlling airborne contamination areas to determine if controls were acceptable. During this review, the inspectors evaluated the adequacy of the dose assessments for any actual internal exposures greater than 50 millirem committed effective dose equivalent.

b. Findings

No findings of significance were identified.

.2 High Risk Significant, High Dose Rate HRA and Very High Radiation Area (VHRA) Controls

a. Inspection Scope

The inspectors reviewed the licensee's controls for access to risk significant HRAs and VHRAs to ensure that the licensee's controls were consistent with the requirements in 10 CFR Part 20 and TSs. Specifically, the inspectors discussed the controls with the radiation protection staff and reviewed applicable procedures. The inspectors also performed walkdowns of the Unit 1 containment building to ensure adequate posting and locking of entrances to high dose rate (>25 rem in one hour at 30 centimeters) HRAs and VHRAs.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed condition reports completed during the previous six months which identified issues in radiation worker and radiation protection technician performance. The inspectors reviewed these documents to assess the licensee's ability to identify repetitive problems, contributing causes, the extent of conditions, and to implement corrective actions which would achieve lasting results.

b. Findings

No findings of significance were identified.

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

.1 Radiological Work/ALARA Planning

a. Inspection Scope

The inspectors examined the station's procedures for radiological work/ALARA planning and scheduling, and evaluated the dose projection methodologies and practices implemented for the 2002 Unit 1 refueling outage to verify that sound technical bases for outage dose estimates existed.

The inspectors reviewed the exposure results and ALARA reviews for selected refueling outage activities to evaluate the accuracy of exposure estimates in the ALARA plans. The inspectors compared the actual exposure results versus the initial exposure estimates, the estimated and actual dose rates, as well as the estimated and actual man-hours expended. The inspectors reviewed the exposure history for each activity and evaluated management involvement in exposure tracking to assess outage dose performance and dose management practices. The inspectors reviewed selected work-in-progress ALARA reviews to determine if additional engineering/dose controls for those activities were necessary, and if required corrective action documents had been generated. Those work activities included:

- Unit 1 SG manway removal;
- Unit 1 SG nozzle dam installation;
- SG diaphragm hot particle retrieval;
- selected inservice inspection (ISI) work;
- removal of insulation; and
- assembling and disassembling of scaffolding.

b. Findings

No findings of significance were identified.

.2 Verification of Exposure Estimate Goals and Exposure Tracking System

g. Inspection Scope

The inspectors reviewed the methodology and assumptions used by the licensee for developing refueling outage exposure estimates and exposure goals. Actual job exposure data was compared with estimates to verify that the licensee could project and, thus, control radiological exposure. The inspectors also reviewed the licensee's exposure tracking system to verify that the level of exposure tracking detail, exposure report timeliness, and exposure report distribution were sufficient to support control of collective exposures. The inspectors evaluated how the licensee had identified problems with its exposure estimates for some jobs, the processes being utilized to revise dose estimates, and methods to improve its dose forecasting procedures to verify that the licensee could adequately track dose.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors observed work activities in the RCA that were performed in radiation areas or HRAs to evaluate the use of ALARA controls. Specifically, the inspectors assessed the implementation of radiation work permits, engineering and ALARA controls, and radiological surveys, and observed pre-job radiological briefings (as available) and radiation protection technician performance for the following Unit 1 refueling work activities:

- Unit 1 SG manway removal;
- Unit 1 SG nozzle dam installation;
- SG diaphragm hot particle retrieval; and
- selected inservice inspection work.

The inspectors also observed radiation worker performance to verify that the training and skill levels demonstrated by the workers was sufficient with respect to the radiological hazards present and the work involved. The inspectors evaluated workers' use of low dose waiting areas and the level of on-the-job supervision to ensure that ALARA requirements were met.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed self-assessments, audits, and condition reports completed during the previous four months which focused on ALARA planning and controls and the radiological source term reduction program. The inspectors reviewed these documents to assess the licensee’s ability to identify repetitive problems, contributing causes, the extent of conditions, and to implement corrective actions which will achieve lasting results.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

The Office of Homeland Security developed a Homeland Security Advisory System (HSAS) to disseminate information regarding the risk of terrorist attacks. The HSAS implements five color-coded threat conditions with a description of corresponding actions at each level. NRC Regulatory Information Summary (RIS) 2002-12a, dated August 19, 2002, “NRC Threat Advisory and Protective Measures System,” discusses the HSAS and provides additional information on protective measures to licensees.

On September 10, the NRC issued a Safeguards Advisory to reactor licensees to implement the protective measures described in RIS 2002-12a in response to the Federal government declaration of threat level “Orange.” Subsequently, on September 24, the Office of Homeland Security downgraded the national security threat condition to “Yellow” and a corresponding reduction in the risk of a terrorist threat.

The inspectors interviewed licensee personnel and security staff, observed the conduct of security operations, and assessed licensee implementation of the threat level “Orange” protective measures. Inspection results were communicated to Region III and Headquarter’s security staff for further evaluation.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Mitigating Systems, Barrier Integrity, and Occupational Radiation Safety

a. Inspection Scope

The inspectors reviewed the performance indicator data submitted by the licensee for completeness and accuracy, and to verify that the licensee had reported data in accordance with the guidance provided by the Nuclear Energy Institute (NEI). The inspectors reviewed documents listed at the end of this report for performance indicator data for mitigating systems and barrier integrity cornerstones. The inspectors reviewed the following performance indicators from the 3rd quarter 2001 through the 2nd quarter 2002:

- Reactor Coolant System Leak Rate on October 11, 2002; and
- Safety System Unavailability - Emergency Alternating Current (AC) Power System on October 24, 2002.

Under the occupational radiation safety cornerstone, the inspectors verified the licensee's assessment of its performance indicator for occupational radiation safety. One reportable element was identified by the licensee for the 2nd quarter of 2002. The inspectors selectively reviewed the licensee's data elements to verify that there were no additional occurrences during the 4th quarter of 2001 and the first three quarters of 2002.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that corrective actions were performed in a timely manner, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are generally denoted in the report.

b. Findings

No findings of significance were identified.

.2 Licensee Resolution of Issues Associated With Unit 1 Emergency Diesel Generators

a. Inspection Scope

On October 1, 2002, the inspectors reviewed the actions taken by the licensee to resolve URI 50/282-01-10-01. This issue dated back to May 16, 2001, and was concerned with the resolution of inadequacies identified in Prairie Island calculations ENG-PI-002, "Probabilistic Risk Assessment of D1 EDG [emergency diesel generator] Room Door Vulnerability to Tornado Missile," and ENG-PI-005, "Tornado & Seismic Evaluation of D1/D2 Components." The inspectors assessed whether the timeliness of the licensee's corrective actions to resolve this issue were commensurate with the safety significance of the issue. The inspectors reviewed USAR and IPEEE sections discussing tornado hardness and seismic qualification for the Unit 1 EDGs and their associated structures, discussed probabilistic risk assessment results assuming that both Unit 1 EDGs and all connections to offsite power are lost during a tornado event with plant risk engineers, and discussed probabilistic risk assessment results with the Region III Senior Reactor Analyst. The inspectors also reviewed the licensee's timeline for correction of the inadequacies in the above referenced calculations.

b. Findings

No findings of significance were identified. Based on licensee corrective actions currently in progress, the inspectors consider URI 50/282-01-10-01 closed.

4OA3 Event Followup (71153)

a. Inspection Scope

The purpose of this inspection was to assess Prairie Island's emergency preparedness response during a seismic event which occurred on November 3, 2002. The inspectors reviewed the operator's response to this unplanned event and compared their actions to the actions specified in annunciator response procedures, abnormal operating procedures, and the emergency plan and implementing procedures.

b. Findings

Introduction

The inspectors identified that the licensee failed to classify and declare an Unusual Event in accordance with emergency plan implementing procedures following receipt of the Seismic Event annunciator with confirmation of the occurrence of an earthquake in Alaska. The finding was considered to be of very low safety significance (Green) and was determined to be a Non-Cited Violation.

Discussion

On November 3, 2002, a seismic alarm was received in the control room. The licensee entered Abnormal Operating Procedure AB-3 and confirmed the occurrence of the Alaskan earthquake by contacting the National Earthquake Information Center in

Boulder, Colorado. The control room seismic monitor energized, the Seismic Event annunciator was received, and magnetic tape operation initiated. However, a failure of the seismic monitor chart paper recorder to produce a visible indication on its chart paper prevented the timely evaluation of the peak acceleration experienced during the event. Additionally, the failure of operators to follow the emergency plan implementing procedure for event classification prevented classification and declaration of the event.

Abnormal Operating Procedure AB-3, Attachment B, directed operators to remove the paper chart from the seismic recorder; determine the peak acceleration of the seismic event; compare the peak acceleration recorded to the acceleration definitions for the Seismic Event, Operational Basis Earthquake, and Design Basis Earthquake; and declare the appropriate emergency action level if necessary. When operators removed the chart paper from the seismic recorder they were unable to read markings on the paper and were unable to promptly determine the peak acceleration of the event. This problem was entered into the corrective action program with AR CAP 026100.

The inability to promptly determine peak acceleration resulted in the inability to complete AB-3, Attachment B. Referring to Step 5.0 of Attachment A of AB-3, operators directed instrument maintenance and engineering personnel to evaluate the magnetic tape recorders. Five hours after the initial indication of the earthquake was received, instrument maintenance and engineering personnel determined the peak acceleration reached during the seismic event was 1 percent of the acceleration due to gravity (g). Operators determined that no emergency action levels were reached and exited AB-3. The licensee recognized the excessive amount of time needed to determine the peak acceleration of the seismic event and entered the condition into their corrective action program with AR CAP 026101.

The licensee declared the seismic monitor inoperable and commenced troubleshooting activities. The inspectors discussed with instrument maintenance personnel the failure of the seismic monitor chart recorder to produce a readable indication of the seismic activity. The inspectors were told that the chart recorder was the light beam galvanometer type and required ultra-violet light sensitive paper to be exposed. The inspectors inquired as to the age of the paper installed in the seismic monitor with respect to its shelf life and was told that there was no shelf life on the paper. After additional prompting by the inspectors and consultation with the manufacturer of the paper, the licensee confirmed that the paper did indeed have a shelf life and the paper installed in the seismic monitor at the time of the event was beyond its 5-year shelf life. The supply chain manager told the inspectors that the paper had not been included in the site's shelf life program. The inspectors identified that the licensee had failed to properly maintain the seismic monitoring equipment. The licensee ordered, received, and installed new ultra-violet sensitive paper into the seismic monitor. The seismic monitor was satisfactorily tested following the installation of the new paper. The corrective actions for this condition were documented in condition evaluation (CE) 001350.

The inspectors reviewed the annunciator response procedures 47023-603 and C81000 for the Seismic Event alarm. The inspectors noted that the annunciator response procedure C81000 indicated that the instrument setpoint for the Seismic Event alarm was 3 percent of the acceleration due to gravity (g) in the vertical or horizontal directions. Analysis of the seismic monitor magnetic tapes showed only a 1 percent g peak acceleration indicating the alarm setpoint was set low in the conservative direction. Instrument maintenance personnel told the inspectors that the seismic monitor had been recently calibrated.

The inspectors reviewed operator actions with respect to the emergency plan implementing procedure F3-2, “Classification of Emergencies.” The inspectors reviewed the operator control room log entries for November 3, 2002, from 4:31 p.m. through 9:31 p.m., noting that the operators only entered the annunciator response procedures C81000 and 47023-603, and abnormal operating procedure AB-3. No log entries were noted that indicated the operators entered F3-2, Attachment 1, Condition 19a, “Earthquake.” Procedure AB-3, Attachment “A,” would have directed the operators to enter F3-2, Attachment 1, Condition 19a, if the seismic monitor paper chart would have functioned properly allowing completion of AB-3, Attachment “B,” and a peak acceleration of greater than or equal to 3 percent g was recorded during the seismic event. As mentioned previously, operators were unable to complete AB-3, Attachment B, and AB-3, Attachment A, Step 2.0. Since Step 2.0 could not be completed, operators skipped Steps 2.0, 3.0, and 4.0. Step 3.0 of AB-3 was the step that referred operators to emergency plan implementing procedure F3-2 for event classification.

Operators should have entered F3-2, Attachment 1, Condition 19a, immediately after the receipt of the Seismic Event alarm. F3-2 requires two conditions to be met necessitating the declaration of an Unusual Event classification. The first condition was the receipt of the Seismic Event annunciator on the seismic monitor. This condition was met on receipt of the alarm at 4:31 p.m. The second condition to confirm the seismic event by one or more offsite sources was met when the licensee confirmed the event with the National Earthquake Information Center in Boulder, Colorado at 4:40 p.m. The inspectors identified that the licensee failed to follow its emergency plan implementing procedure for this event. The licensee entered the issue into their corrective action program as Other (OTH) 023756. This document specified an evaluation of the licensee’s actions for the November 3, 2002, event.

The licensee told the inspectors that the operators did not enter F3-2 and classify the event because they did not believe the event to be of sufficient magnitude to warrant an unusual event declaration. Operators based their decision on the significant distance between the plant site and the earthquake’s epicenter, the absence of earth motion at the plant site as sensed by on-shift plant personnel, and confirmation from the nearby Monticello plant that the event was not detected on their seismic monitors. The verification of seismic activity with the Monticello plant occurred approximately 2 hours after the Seismic Event annunciator was received.

The inspectors reviewed the licensee’s reasoning for not declaring the event and determined that the actions taken by the licensee did not meet the timeliness requirements for event classification and declaration. The regulations do not provide an explicit time limit for classification but do imply that the classification should be made without delay. An event classification time limit of 15 minutes has been accepted by both the NRC and industry. In August of 1995, the NRC issued Emergency Preparedness Position (EPPOS) Number 2, discussing NRC expectations for the timeliness of the classification of emergency conditions. This expectation has been further communicated in industry guidance. Nuclear Energy Institute 99-02, Section 2.4, provided a definition of timely that stated that classifications are made consistent with the goal of 15 minutes once plant parameters reach an Emergency Action Level. In this case, plant parameters (i.e., the Seismic Event annunciator) reached a Emergency Action Level at 4:31 p.m. The information possessed by the licensee at 4:46 p.m. (15 minutes after the receipt of the Seismic Event annunciator) met all criteria for the classification and declaration of an Unusual Event and, therefore, should have been declared at that time.

The inspectors also identified that the procedural guidance contained in AB-3 and F3-2 conflicted. For example, following AB-3, operators must receive a seismic monitor alarm, verify the magnitude of the peak acceleration, and confirm the event with at least one off-site source; whereas, following F3-2, operators need only to receive a seismic monitor alarm and confirm the event with at least one off-site source before declaring an Unusual Event. The issue of conflicting procedural guidance was entered into the corrective action program with AR CAPs 027232 and 027233.

Analysis

The inspectors determined that this event did not have any actual safety consequences or potential for impacting NRC's regulatory function. However, the licensee's failure to make an emergency classification was considered more than minor since it affected an Emergency Preparedness Cornerstone objective. The affected objective is the emergency response organization's performance in an event to ensure that Prairie Island is capable of implementing adequate measures to protect public health and safety during an emergency.

Consequently, this issue represents a finding that is more than minor and which was evaluated using the Emergency Preparedness Significance Determination Process contained in Appendix B to Manual Chapter 0609. Since the finding involved a failure to meet a regulatory requirement, but did not represent a failure to meet the planning standards of 10 CFR 50.47(b) or those of Appendix E to 10 CFR Part 50, the finding was determined to be of very low safety significance (Green).

Enforcement

In part, 10 CFR 50.54(q), 50.47(b)(4), Sections IV.B and IV.D.3 of Appendix E of 10 CFR Part 50 require that an emergency classification declaration be made promptly after an emergency action level is met. Contrary to the above, the licensee failed to classify and declare an Unusual Event on November 3, 2002, when all required conditions necessitating classification and declaration of an Unusual Event were met. Since the licensee entered the conditions identified by the inspectors into their corrective action program with OTH 023756, this violation is being treated as an NCV in accordance with VI.A.1 of the NRC's Enforcement Policy (NCV 50-282/306/02-09-05).

4OA5 Other Activities

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

a. Inspection Scope

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

The objective of TI 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles,” was to implement an on-site NRC review of the licensees' activities in response to NRC Bulletin 2002-02. Specifically, licensee procedures, equipment, and personnel used for VHP examinations were evaluated by the inspectors to confirm that the licensee met commitments associated with Bulletin 2002-02.

From November 18 through November 26, 2002, the inspectors performed a review of the licensee's activities in response to commitments made to NRC Bulletin 2002-02. In response to Bulletin 2002-02, the licensee referred to previous commitments made in response to Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles.” In response to Bulletin 2001-01, the licensee committed to perform an “effective visual examination” of the vessel head and penetration nozzles. To assess the licensee's efforts in conducting an “effective visual examination” of the RPV head and VHP nozzles, the inspectors:

- performed an independent direct visual examination of the nozzle-to-head interface for portions of 20 VHPs;
- observed the licensee's visual examination of the VHPs;
- interviewed nondestructive examination personnel;
- reviewed the head inspection work order; and
- reviewed the head inspection examination results.

Additionally, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation to:

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

b. Observations

Summary

The licensee did not identify any leaking VHP nozzles. The licensee identified three nozzles with white deposits at the VHP nozzle-to-head interface which were not considered indications of VHP leakage.

Evaluation of Inspection Requirements

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

1. Was the examination:

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

Yes. The licensee conducted a direct visual examination of the head with a knowledgeable staff member certified to Level II as a VT-2 examiner in accordance with programs meeting the American Society for Nondestructive Testing Recommended Practice SNT-TC-1A.

b. Performed in accordance with approved procedures?

No. The licensee conducted direct visual examinations in accordance with requirements of a reviewed and approved work order (WO 0200959, "Inspect RV [reactor vessel] Head Penetrations for Leakage"). The use of a work order was consistent with licensee commitments to Bulletin 2001-01. The licensee acceptance criteria established in this work order included "the lack of any relevant indications of the type described in Electric Power Research Institute TR-1006899, 'Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head.'" The inspector concluded that this criterion was consistent with the licensee's commitment to Bulletin 2001-01, which stated "no visual indications of cracks or leaks." The licensee's visual inspection scope was not explicitly defined in the work order. The work order required the licensee inspection personnel to document the examination coverage on an attached worksheet. The inspectors confirmed that the licensee had not committed to complete a 360 degree visual examination of each penetration nozzle.

The inspectors identified that the work order did not implement visual examination quality standards such as those described for visual VT-1, VT-2, and VT-3 examinations in Section XI of the ASME Code. Based on this observation, the licensee changed the work order to implemented a visual quality check for this examination that included resolution of a 1/32 black line on an 18-percent neutral gray card (visual acuity card). The work order did not specify at what distance the licensee's inspector was required to resolve the line on the visual acuity card. The inspectors noted that the licensee inspector was able to resolve this line at distances in excess of five feet. Specifically, the licensee inspector mounted the visual acuity card on a pole and placed it on the vessel head with the portable lighting used during the head examination and was able to resolve the line.

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

Yes. Based on direct observation of the head and penetration nozzles, the inspectors concluded that the lighting and access for the visual examination was adequate to detect boric acid deposits. The licensee's examinations identified three locations (D-12, D-10 and I-11) with white deposits at the VHP nozzle-to-head interface. The licensee characterized these deposits as white flakes and fluffy-yellow/white deposits. The size of two deposit particles was recorded as 1/4- by 1/16-inch and 1/16- by 1/16-inch. The licensee subsequently removed these deposits with a vacuum. Because of the small size and the loose/readily removable nature of these deposits, the licensee did not consider the deposits to be indicative of leakage. The licensee documented the vessel head inspection results in the corrective action system (CAP 026636).

d. Capable of identifying the primary water stress corrosion cracking phenomenon described in the bulletin?

Yes. The inspectors determined through direct observations, interviews with inspection personnel, and reviews of the work order and examination reports that the licensee's efforts were capable of detecting and characterizing leakage from cracking in VHP nozzles. The inspectors determined that the inspection personnel had access to each of the head penetrations (40 total) and head vent nozzle.

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

The reactor head was covered with reflective metal insulation panels installed on a support structure over the top of the reactor head. The insulation was nominally 3 inches thick and was composed of layers of thin stainless steel sheets. Clearance between the head and insulation was approximately 1 inch at the center and 18 inches at the outside nozzles. The insulation structure included four rectangular view ports (5.5 inches by 16 inches), which allowed the licensee access to the bare metal head. The inspector confirmed that most nozzles were readily visible through these viewing ports and that the head was relatively free of debris which would hinder an effective visual examination. With the aid of a mirror, the licensee's inspection staff were able to obtain a 360-degree visual examination of each VHP nozzle-to-head interface through these viewing ports. However, the inspectors could not confirm that the licensee had sufficient access to penetration nozzle L-10 to permit a 360-degree inspection. This nozzle was in close proximity to the vertical reflective metal head insulation panel on the downhill side. The licensee's inspector considered that his inspection was adequate to have detected leakage with the penetration in this configuration.

The licensee's examinations identified three locations (D-12, D-10 and I-11) with white deposits at the VHP nozzle-to-head interface (CAP 026636). The inspectors questioned if these deposits would obstruct or mask leakage deposits at the VHP nozzle-to-head interface. The licensee's inspector did not consider that these deposits would mask any leakage deposits because leakage deposits would be tightly adherent and would remain at the interface following removal of the loose deposits with a vacuum. The inspectors observed VHP nozzle D-12 (with white deposits) prior to, and after vacuum cleaning. The inspectors did not see any deposits remaining at the VHP nozzle-to-head interface following cleaning.

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

   Yes. The inspectors determined through direct observations, interviews with inspection personnel, and reviews of the work order and examination reports that small boron deposits, as described in the Bulletin 2001-01, could be identified and characterized.

4. What material deficiencies (associated with the concerns identified in the bulletin) were identified that require repair?

   None. The licensee did not identify any materiel deficiencies associated with the 40 VHP nozzles or head vent nozzle that were considered indicative of leakage. Thus, the licensee did not identify material deficiencies associated with concerns identified in the bulletin which required repair.

5. What, if any, significant items that could impede effective examinations?

   The inspectors did not identify any significant items which would impede an effective visual examination.

Nozzle Susceptibility Ranking Calculation

The licensee performed Calculation ENG-ME-535 to determine the effective degradation years (EDY) for the VHP nozzles in Units 1 and 2. In Bulletin 2002-02, the EDY is used as a basis to establish appropriate inspection programs for VHP nozzles based on increasing susceptibility to nozzle cracking with increasing EDY. For Unit 1, the licensee calculated an EDY of 10.58 years through September of 2002. Based on this EDY and the guidance on acceptable inspection programs discussed in Bulletin 2002-02, the licensee chose to perform a visual examination of the head during this refueling outage.

The inspectors confirmed that the formula used by the licensee in Calculation ENG-ME-535 was identical to the formula discussed in Bulletin 2002 to calculate EDY. As an input to Calculation ENG-ME-535, the licensee used a normal operating reactor vessel head temperature of 580.2 degrees Fahrenheit (°F). This temperature was taken from Table 5-2 in a proprietary Westinghouse document WCAP 14918, "Probabilistic Evaluation of Reactor Vessel Closure Head Penetration Integrity for Prairie Island Units 1 and 2." The licensee did not have any records onsite to confirm the inputs used by the vendor in determining the vessel head temperature. The licensee subsequently entered this issue into the corrective action program CAP 026603 and initiated Engineering Work Request (EWR) 0036068, “Heat Temperature Input to Calc ENG-ME-535," to obtain appropriate documentation.

The inspectors’ questions about the input temperature used in the calculation prompted the licensee to contact Westinghouse, who identified that the 580.2 °F head temperature was based, in part, on Calculation Note EMT-97-78. This calculation used a computer program (THRIVE) to determine upper bulk mean fluid temperature of the vessel head area for use in loss-of-coolant accident analysis blowdown load calculations. For that application, the Westinghouse had used a cold leg temperature of 527 °F vice the actual in-plant measured value of 530 °F. Westinghouse reported that the output of this calculation performed in 1992 for the upper bulk mean fluid temperature was 577.2 °F. Westinghouse then added 3 °F to adjust for the plant specific cold leg temperature difference to obtain the 580.2 °F value used in WCAP 14918 and as the input value for head temperature in Calculation ENG-ME-535.

In addition to the EDY, an acceptable VHP inspection program was based on whether the licensee had identified cracks or leakage during previous inspections of VHP nozzles. Based on discussions with licensee inspection personnel, the inspectors confirmed that no indications of VHP nozzle leakage had been identified during previous Unit 1 head inspections. However, the licensee inspector reported that a complete 360 degree visual examination of each VHP nozzle-to head interface had not been performed during the previous Unit 1 visual examination.

c. Findings

No findings of significance were identified.

.2 Completion of TI 2515/149, Mitigating Systems Performance Index (MSPI) Pilot Verification

From November 25 through December 20, 2002, the inspectors completed the requirements of the TI to verify that the licensee had correctly implemented the MSPI pilot guidance for reporting unavailability and unreliability of the monitored safety systems. Documents reviewed during this inspection are listed at the end of this report. The detailed results of this inspection are documented in a memorandum included as an attachment to this report.

.3 Completion of Appendix A to TI 2515/148, Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures, Revision 1

The inspectors completed the pre-inspection audit for interim compensatory measures at nuclear power plants, dated September 13, 2002.

4OA6 Meeting(s)

.1 Interim Exit Meetings

Results of Licensed Operator Requalification Testing for Calender Year 2002 and Applicability of NRC IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," with Mr. T. Bacon on November 14, 2002.

Access Control to Radiologically Controlled Areas and ALARA inspection with Mr. M. Nazar on November 22.

TI 2515/150 and inservice inspection (IP 7111108) with Mr. M. Nazar on November 26.

.2 Exit Meeting

The resident inspectors presented the inspection results to Mr. M. Nazar and other members of licensee management on January 13, 2003. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Mitigating Systems

.1 Missed Technical Specification Surveillance Test

Technical Specification Condition 3.7.8.A, "Cooling Water System," states that with no safeguards cooling water pumps operable in one train, then on Unit 1 enter the applicable conditions of the required actions of the Limiting Condition for Operation 3.8.1, "AC Sources." Technical Specification Condition 3.8.1.A states that surveillance requirement (SR) 3.8.1.1 shall be performed within one hour and every eight hours thereafter. On October 26, 2002, the licensee identified that they had failed to meet these requirements on October 24, when the 22 safety-related DDCL pump was declared inoperable for planned maintenance. Upon discovery of the missed surveillance activity, the licensee performed and successfully completed SP 1118, "Verifying Paths from the Grid to Unit 1 Buses," and conducted an investigation that did not identify any degradations in the offsite alternating current power sources. The finding was determined to be of very low safety significance since it did not result in any actual loss of safety function. This issue was entered into the licensee's corrective action program with AR CAP 025986.

.2 Inoperable RHR Suction Relief Valve

The Design Basis Document (DBD) System 15, "Residual Heat Removal System," requires that the RHR system be protected from over-pressure in accordance with the ASME Boiler and Pressure Vessel Code, 1968 Winter. Relief Valve RH-8-1 was intended to perform this function on Unit 1. However, on November 18, 2002, the licensee identified that RH-8-1 had been gagged and was not able to perform its pressure relief function. The valves's work history indicated that it had been gagged since its installation in April 1999. The installation of the gagging device on RH-8-1 constituted a change to the design of the RHR system as described in its design basis and was inconsistent with the design control requirements of 10 CFR 50, Appendix B, Criterion III. The finding was determined to be of very low safety significance since at no time did RHR system pressure approach the piping design pressure nor did it result in non-compliance with low temperature over-pressure protection TSs, increase the likelihood that a loss of decay heat removal would occur, increase the likelihood that a loss of RCS inventory would occur, increase the likelihood that a loss of offsite power would occur, degrade the capability to terminate a leak path or add RCS inventory, degrade the ability to recover decay heat removal once lost, degrade the ability to establish an alternate core cooling path, or degrade the ability of containment to remain intact following a severe accident. This issue was entered into the corrective action program with AR CAP 026440.

KEY POINTS OF CONTACT

Licensee

T. Amundson, Manager Business Support
P. Huffman, Manager of System Engineering
J. Jensen, Production Planning Manager
A. Johnson, Radiation Protection Manager
J. Kivi, Licensing Engineer
R. Lingle, Operations Manager
M. McKeown, Manager of Design Engineering
M. Ladd, General Superintendent Plant Maintenance
M. Nazar, Site Vice President
S. Northard, Director of Engineering
J. Waddell, Superintendent Security
M. Werner, Plant Manager
P. Wildenborg, Lead Technical Health Physicist
R. Womack, Manager of Engineering Programs

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/306/02-09-01	NCV	Failure to Follow Internal Flood Control Procedure (Section 1R06)
50-282/306/02-09-02	URI	Missed UT Examinations for SG 12 and SG 21 W-A Welds (Section 1R08.b.(1))
50-282/306/02-09-03	NCV	Lack of ASME Code Requirement in 3 UT procedures (Section 1R08.b.(2))
50-282/306/02-09-04	NCV	Missed Technical Review for UT Procedure (Section 1R08.b.(3))
50-282/306/02-09-05	NCV	Missed Emergency Classification and Declaration (Section 4OA3)

Closed

50-282/306/02-09-01	NCV	Failure to Follow Internal Flood Control Procedure (Section 1R06)
50-282/306/02-09-03	NCV	Lack of ASME Code Requirement in 3 UT Procedures (Section 1R08.b.(2))
50-282/306/02-09-04	NCV	Missed Technical Review for UT Procedure (Section 1R08.b.(3))

50-282/306/02-09-05	NCV	Missed Emergency Classification and Declaration (Section 4OA3)
50-282/01-10-01	URI	Ability of D1 and D2 Exhaust Lines to Survive a Design Basis Tornado or Seismic Event (Section 4OA2.2)
50-282/306/02-08-02	URI	Maintenance Rule Functional Failure Evaluation of Bypass Gate Failures (Section 1R12.3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

Cold Weather Preparations

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1R04 Equipment Alignment

12 DDCL Pump Partial Walkdown

TS 3.7.8; Cooling Water System; Amendment 158

USAR 10.4.1; Cooling Water System; Revision 24

C35; Cooling Water Operating Procedure; Revision 49

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1R05 Fire Protection

Area Walkdowns
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1R07 Heat Sink Performance
TS 3.7.7; Component Cooling Water System; Amendment 158

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<u>Reduced Inventory Operation</u>
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<u>Unit Startup</u>
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1R15 Operability Evaluations

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Plant Status Report; November 6, 2002

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TS 3.7.8; Cooling Water System; Revision 131

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1R19 Post-Maintenance Testing

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AR CAP 025841; 124 Air Compressor Cooling Jacket Full of Mud; October 17, 2002

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1R20 Refueling and Other Outage Activities

5AWI 15.6.1; Shutdown Safety Assessment; Revision 1

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1R22 Surveillance Testing

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SP 1834; Unit 1 Containment Coating Inspection; Revision 0

<u>SP 1070, Reactor Coolant System Integrity Test</u>

WO 0114211; Reactor Coolant System Integrity Test; December 3, 2002

SP 1070; Reactor Coolant System Integrity Test; Revision 33

AR CAP 027049; Excess Letdown Heat Exchanger Endbell Flange Leak During SP 1070; December 5, 2002

SP 1750, Post Outage Containment Close-Out Inspection
WO 0114186; Post Outage Containment Close-Out Inspection; November 29, 2002

SP 1750; Post Outage Containment Close-Out Inspection; Revision 25

1R23 Temporary Modifications

Cooling Water Pipe Patch
Temporary Modification 02T131; Containment Cooling Line 14-ZX-6 Pipe Patch; May 10, 2002

NMC Standard 10 CFR 50.59 Screening 1487; Revision 0

AR CAP 024556; ZX [Containment Cooling] Piping Inclusion On Top Ten Equipment List; August 8, 2002

AR CAP 021192; Leak on Chill Water Line 14-ZX-6, the Common Header to Unit 1 and Unit 2 ; March 27, 2002

CA001896; Perform Action Plan for ZX Piping to Increase Reliability; August 10, 2002
Construction Code B 31.1; 1969

Prairie Island USAR, Section 5.2.2.3.1; Containment Air Cooling Systems; Revision 22

Instrument Air Pipe Clamp
Temporary Modification 02T147; Instrument Air Pipe Clamp

NMC Standard 10 CFR 50.59 Screening 1632; Revision 0

Operations Logs; 10/22/02, 9:18 P.M.

5AWI 6.5.0; Temporary Modifications; Revision 11

DBD SYS-34; Design Basis Document - Station and Instrument Air System; Revision 4W

Prairie Island USAR, Section 10.3.10.2.2; Instrument Air System; Revision 23

1EP6 Drill Evaluation

PINGP Emergency Plan Drill Package; October 23, 2002, Revision 0

PINGP Emergency Plan Drill Critique Report; October 23, 2002

AR CAP 025951; 2002 Fall Drill - Dosimeters Were Not Distributed to Security; October 24, 2002

AR CAP 0025952; 2002 Fall Drill - Plant Evacuation Ordered in an Untimely Manner; October 24, 2002

AR CAP 0025955; 2002 Fall Drill - Provide an Evacuation Switch in the Technical Support Center; October 24, 2002

AR CAP 0025956; Establish Fast-Track Dispatch for Duty Operators from Operational Support Center; October 24, 2002

AR CAP 0025957; 2002 Fall Drill - Cross-Tie of 480-Volt Safeguards Buses Considered Untimely; October 24, 2002

2OS1 Access Controls for Radiologically Significant Areas

Radiation Protection Implementing Procedure (RPIP) 1133; Multiple TLD [Thermoluminescent Luminescent Dosimeter] Badging; Revision 8

RPIP 1135; RWP [Radiation Work Permit] Coverage; Revision 13

AR CAP 023388; Radiological Postings Removed; May 6, 2002

AR CAP 023386; Contamination Found in a Clean Area Around U2 RHR Pits; May 6, 2002

AR CAP 023404; Operator Reached Across a Rad Boundary and Operated a Valve with Bare Hands; May 7, 2002

AR CAP 026493; High Radiation Area Boundary Left Down; November 20, 2002

AR CAP 023449; Neutron Posting Left Down; May 9, 2002

AR CAP 023459; Roll-up of Rad Worker Practices Issues for the Week Ending 5/9/02; May 10, 2002

AR CAP 023478; Operator Received a Dose Alarm While in the RHR Pit; May 13, 2002

AR CAP 023566; Worker Received Dose Alarm During Spent Fuel Pool Skimmer Filter Change-out; May 20, 2002

AR CAP 023912; Barrel Yard RCA Boundary Was Left Down and Unattended; June 20, 2002

AR CAP 023914; Worker Exhibiting Poor Rad Practices; June 20, 2002

AR CAP 023930; Snubber Test Stand Found to be Contaminated During Routine Survey; June 21, 2002

AR CAP 023974; Contaminated Area Incorrectly Posted; June 25, 2002

AR CAP 024061; Locked HRA Sign Was Found Laying on the Floor Near Locked HRA; July 3, 2002

AR CAP 024220; Radiologically Controlled Areas Have Dual Postings; July 18, 2002

AR CAP 024286; Green Drain Hose Internally Contaminated; July 22, 2002

AR CAP 025715; Rad Worker Practice Changes Not Adequately Conveyed to Plant Personnel; October 11, 2002

AR CAP 025915; Painter Received a Dose Alarm on His ED [Electronic Dosimeter] While in ISFSI [Independent Spent Fuel Storage Installation]; October 22, 2002

AR CAP 026095; Individual Left RCA Prior to Clear Friskall; November 2, 2002

AR CAP 02339; Worker Sweeping from Inside Contaminated Area to Outside the Area; November 16, 2002

AR CAP 026493; High Radiation Area Boundary Left Down; November 20, 2002

2OS2 ALARA Planning and Controls

SA 021671; Radiation Protection Self Assessment; September 13, 2002

D27.18; Special Operations Procedure - Stem Generator Nozzle Dam Installation; Revision 22

MSIP 7009; Steam Generator Nozzle Dam Installation Pre-job Briefing

RPIP 1004; Radiation Protection ALARA Program; Revision 5

5AWI 10.1.1; ALARA Plan; Revision 0

RWP 1022; ALARA Review 2002 U1 SG Primary Manway Remove and Install; October 8, 2002

RWP 1027; ALARA Review 2002 U1 SG Primary Nozzle Dam Install and Remove and SG Closeout Inspection; October 14, 2002

PINGP 1112; Pre-job Brief - 12 CL Insert and Hot Particle Removal; November 19, 2002

AR CAP 023227; Investigate Potential Negative Trend in Entering Controlled Area Without Electronic Dosimetry; April 22,2002

AR CAP 023724; Maintenance Working in Contaminated Area After Hours with No HP [Health Physics] Support; June 6, 2002

AR CAP 023725; U2 CS Pump Room Scaffold Added to Work Week Without Informing ALARA Contact; June 6, 2002

AR CAP 023992; Emergency Electronic Dosimeter Alarm Set-points Were Not Reset Before Issue; June 26, 2002

AR CAP 024129; Operators Performed SP 2090A Under Wrong RWP; July 12, 2002

AR CAP 024140; Clean Area in U2 CS Pump Room Was Contaminated While Performing SP 2090A; July 12, 2002

AR CAP 025131; WO 200241 is for Work in Containment and RWP Required Block Was "N"; September 10, 2002

AR CAP 025490; Dose Goal Not Met 9/22 to 9/29/02; September 30, 2002

AR CAP 026489; Outage Delay and Extra Dose Due to Discreet Radioactive Particle on 12 S/G Cold Leg Diaphragm; November 20, 2002

4OA1 Performance Indicator Verification

Reactor Coolant System Leakage
TS 3.1.8; Reactor Coolant System Leakage; Revision 91

Operations Log Entries, Units 1 and 2; August 1, 2001, through September 1, 2002

AR CAP 025257; Potentially Incorrect Primary to Secondary Leak Rate Values; September 17, 2002

SP 1001AA; Daily Reactor Coolant System Leakage Test; Revision 30

WO 0205837; SP 1001AA Daily Reactor Coolant System Leakage Test; October 10, 2002

Safety System Unavailability - Emergency AC Power System
Performance Indicator Data Summary Reports; Safety System Unavailability - Emergency AC Power System; 4th Quarter 2001, 1st Quarter 2002, 2nd Quarter 2002, and 3rd Quarter 2002

Operations Log Entries; Unit 1 and Unit 2 Control Room; October 1, 2001, through October 24, 2002

SP 2093; D5 Diesel Generator Monthly Slow Start Test; Revision 71

SP 2305; D6 Diesel Generator Monthly Slow Start Test; Revision 19

Occupational Radiation Safety
AR CAP 024181; Radiation Area Sign Was Found Laying on the 695' Drop Area Floor; July 16, 2002

AR CAP 025662; Radiation Area Sign Found Down; October 8, 2002

AR CAP 026004; Potential Adverse Trend in Rad Worker Practices; October 28, 2002

AR CAP 026093; High Radiation Area Key Locker Was Found Open and Unguarded at Access; November 2, 2002

4OA2 Identification and Resolution of Problems
Letter From Walter Djordjevic To Mark McKeown; Walkdown Assessment of D1/D2 [Emergency Diesel Generators] Tornado Missile Vulnerability; September 10, 2002

GEN-PI-005; Tornado and Seismic Evaluation of D1 and D2 Components; Revision 0

ENG-CS-233; Tornado Missile Evaluation; Revision 0

ANSI/ANS-2.3-1983; Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites; American Nuclear Society, 1983

USAR Table 12.2-1; Classification of Structure, Systems, and Components; Revision 23

DBD TOP-05; Hazards; Revision 2W

DBD STR-03; Turbine Building; Revision 2W

GEN 20014805; Inadequate D1/D2 Diesel Tornado Damage Analysis; June 7, 2001

AR CAP 000137; Inadequate D1/D2 Diesel Tornado Damage Analysis; June 4, 2001

OPR 000054; Operability Recommendation CAP 000137

4OA3 Event Followup
Response to a Seismic Alarm Received Following Alaskan Earthquake
Abnormal Operating Procedure, AB-3; Earthquakes; Revision 18

Emergency Plan Implementing Procedure F3-2; Classification of Emergencies; Revision 30

Technical Requirements Manual, Section 3.3.4; Miscellaneous Instrumentation; Revision 3

Operations Logs, Control Room; November 3 through November 4, 2002

Alarm Response Procedure 47023-0603; Seismic Event; Revision 23

Remote Alarm Response Procedure C81000; Seismic Event; Revision 0

5AWI 8.2.4; Shelf Life Program; Revision 0

AR CAP 026100; Seismic Equipment, Unable to Read Chart; November 3, 2002

AR CAP 026101; Delay In Confirming Magnitude of Seismic Activity; November 3, 2002

AR CAP 027235; Evaluate and/or Determine Maintenance Department Shelf Life Controls; December 13, 2002

CE 001350; Evaluate and If Necessary Initiate Corrective Action Regarding CAP 026201; November 7, 2002

OPR 000350; Operability of Seismic Monitor Chart Recorder as Used In AB-3; November 4, 2002

AR CAP 027232; Improved Guidance Needed In F3-2 Regarding Classification of Earthquakes; December 13, 2002

AR CAP 027233; Improved Guidance Needed In AB-3 “Earthquakes”; December 13, 2002

CA 003539; Evaluate and If Necessary Initiate Corrective Action Regarding CAP 027232; December 17, 2002

CA 003540; Evaluate and If Necessary Initiate Corrective Action Regarding CAP 027233; December 17, 2002

PINGP 1224; Crew Meeting Review of Noteworthy Event/Near Miss/Change; November 8, 2002

SWI EP-300; Emergency Plan Activation Evaluation; Revision 0

OTH 023756; Using Guidance of SWI EP-300, Emergency Plan Activation Evaluation, Relative to the November 3, 2002, Seismic Annunciator Alarm Event; January 9, 2003

EPPOS No. 2; Emergency Preparedness Position On Timeliness Of Classification Of Emergency Conditions, Revision 0

NEI 99-02, Section 2.4; Emergency Preparedness Cornerstone; Revision 2

4OA5 Other Activities

TI 2515/149; Mitigating Systems Performance Index Pilot Verification; September 24, 2002

Draft NEI 99-02 MSPI, Appendix F; Methodologies for Computing the Unavailability Index and Determining Performance Index Validity; Revision 0

Draft NEI 99-02 MSPI, Attachment A; Mitigating System Performance Index; September 24, 2002

Electronic Control Room Logs; July 1, 2000, through September 30, 2002

Electronic Limiting Conditions for Operations Logs; July 1, 2000, through September 30, 2002

Excel Spreadsheets for MSPI Data Submittals, Baseline Data; 2nd Quarter 2002, and 3rd Quarter 2002

Performance Indicator Data; from www.nrc.gov/NRR/OVERSIGHT/ website; 3rd Quarter 2000 through 3rd Quarter 2002

Prairie Island MSPI Notebook

4OA7 Licensee-Identified Violation

PINGP TS, Section 3.7.8; Cooling Water System; Amendment 158

PINGP TSs, Section 3.7.8; AC Sources; Amendment 158

AR CAP 025986; Missed Forced Cascade During 22 DDCL Pump Outage; October 26, 2002

CE 001282; Evaluate Potential Reportability of Failure to Complete SP 1118; October 29, 2002

Root Cause Evaluation 000175; Perform Root Cause Evaluation into 22 DDCL Pump Issue; October 29, 2002

Operator Logs from October 24 through October 26, 2002

SP 1118; Verifying Paths from the Grid to Unit 1 Buses; Revision 15

DBD SYS-15; Design Basis Document for the Residual Heat Removal System; Revision 3

1C1.3; Unit 1 Shutdown Procedure; Revision 50

USAR Section 4.4.3.3; Low Temperature Overpressurization Mitigation; Revision 23

USAR Section 6.2; Safety Injection System; Revision 22

TS 3.4.12; Low Temperature Overpressure Protection; Amendment 158

TS 3.4.13; Low Temperature Overpressure Protection; Amendment 158

AR CAP 026440; Discovered Test Rod Installed on RH-8-1, 11/12 RHR Pumps Suction; November 18, 2002

ACE 008610; Conduct ACE Regarding CAP 026440; November 20, 2002

OPR 000358; Determine if Valve/RHR is Operable in This Configuration; November 19, 2002

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AR	Action Request
ASME	American Society of Mechanical Engineers
AWI	Administrative Work Instruction
B	Barrier Integrity
CA	Caustic Addition
CAP	Corrective Action Program
CC	Component Cooling Water
CE	Condition Evaluation
CL	Cooling Water
CS	Containment Spray
CFR	Code of Federal Regulations
DBD	Design Basis Document
DDCL	Diesel-Driven Cooling Water
°F	Degrees Fahrenheit
DRP	Division of Reactor Projects
ED	Electronic Dosimeter
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
EPPOS	Emergency Preparedness Position
ET	Eddy Current
EWR	Engineering Work Request
GEN	General Condition Report
GTAW	Gas Tungsten Arc Welding
HC	Hydrogen Control
HP	Health Physics
HRA	High Radiation Area
HSAS	Homeland Security Advisory System
IE	Initiating Event
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
IPEEE	Individual Plant Examination of External Events

IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
ISI	Inservice Inspection
LOCA	Loss of Coolant Accident
MCC	Motor Control Center
MDCL	Motor-Driven Cooling Water
MRE	Maintenance Rule Evaluation
MS	Mitigating System
MSIP	Maintenance Standards Implementing Procedure
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NMC	Nuclear Management Corporation, LLC
NRC	U.S. Nuclear Regulatory Commission
NSP	Northern States Power
OTH	Other
OPR	Operability Recommendation
OWA	Operator Workaround
PARS	Publicly Available Records
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
PMT	Post-Maintenance Test
PT	Dye Penetrant
PWR	Pressurized Water Reactor
RC	Reactor Coolant
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RIS	Regulatory Information Summary
RPIP	Radiation Protection Implementing Procedure
RPV	Reactor Pressure Vessel
RV	Reactor Vessel
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SP	Surveillance Procedure
SR	Surveillance Requirement
TB	Terminal Box
TDAFW	Turbine-Driven Auxiliary Feedwater
TI	Temporary Instruction
TLD	Thermoluminescent Dosimeter
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area

WO	Work Order
ZX	Containment Cooling

December 20, 2002

MEMORANDUM TO: John Thompson, Senior Reactor Operations Engineer
Inspection Programs Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

THRU: Ken Riemer, Branch Chief
Reactor Programs Branch 5, Region III

FROM: John Adams, Senior Resident Inspector, Prairie Island

SUBJECT: COMPLETION OF TEMPORARY INSTRUCTION (TI) 2515/149 AT PRAIRIE ISLAND

The inspectors completed the requirements of TI 2515/149, “Mitigating Systems Performance Index (MSPI) Pilot Verification,” at Prairie Island on December 20, 2002. The inspectors determined that the licensee made a reasonable best effort to provide accurate and complete data for this voluntary pilot program. Most data errors were small and most other problems were because the guidance for the MSPI program was still under development.

The following discrepancies/issues were noted: (Paragraph numbers correspond to the inspection requirements sections of TI 2515/149.)

03.02 Risk-Significant Functions

- The licensee did not originally specify which Maintenance Rule risk-significant functions were to be counted as MSPI functions. All Maintenance Rule functions were listed. Licensee engineers revised the list of functions during the inspection.

- The licensee originally listed the auxiliary feedwater (AFW) system function as “To provide water to the steam generators ...” Since the success criterion is met by only supplying flow to one steam generator, the function should have been stated as “To provide water to at least one steam generator ...” to be consistent with Nuclear Energy Institute (NEI) 99-02, draft Attachment A. Licensee engineers corrected the function description during the inspection.

- The licensee did not include the electrical cross-ties from the other unit’s safeguards busses as a risk-significant function of the emergency AC power (EAC) system although it is modeled in its probabilistic risk assessment (PRA) and is a significant factor in calculating the Fussell-Vesley (F-V) value. (See additional comments under 03.04.)

03.03 Success Criteria

- The licensee's MSPI and Maintenance Rule success criteria for AFW included providing 200 gallons per minute (gpm) to at least one steam generator within one minute at 1300 pounds per square inch - atmosphere (psia). The licensee's design basis documentation (DBD) stated success is 200 gpm to at least one steam generator within one minute at 1142.6 pounds per square inch - gauge (psig). Licensee engineers revised the MSPI success criteria to match the design basis of 1142.6 psig during the inspection.

- The licensee's MSPI success criteria did not indicate where the parameters specified came from (such as DBD, Updated Safety Analysis Report (USAR), or PRA). The licensee was informed that this information should be available for inspection.

- One of the success criteria for the component cooling water (CC) system was listed as 200 degrees. This was a piping design limit but obviously the system could not meet its function of cooling front line systems if it were that hot. The licensee was informed that this criterion should be revised.

03.04 Unreliability Boundary Definition

- For AFW, the licensee did not document why the valves in the safety-related backup water supply from the cooling water system were not included as active components.

- The licensee did not document why AFW steam generator isolation valves (such as MV-32242) are not considered active components like they did for the throttle valves (such as MV-32238).

- For AFW, the licensee included the recirculation valves (CV-31153, CV-31154, CV-31418, and CV-31419) as active components but they have no F-V because they are not modeled in the PRA. There was a statement in the licensee's MSPI documentation that the valves will be modified to be normally open, but that is not true anymore. Since the valves have no F-V values, unreliability data submitted for these valves do not get counted in the MSPI calculation.

- For the cooling water (CL) system, the licensee did not document why dump-to-grade valves MV-32329, 32322, and 32036 were not included as active components.

- For CC, the licensee included MV-32120 and other valves as active components but they had zero F-V values assigned. The licensee documented a qualitative discussion as to why the F-V valves would be negligible, but did not provide any quantitative evaluation to support it. The licensee stated that the valves were modeled in the PRA and that they would provide the quantitative importance values. Since the valves have such low F-V values, their unreliability data do not contribute to the MSPI calculation.

- For CL, the heat exchanger throttle valves (CV-31381, CV-31411, CV-31383, and CV-31384) are included as active components but are not modeled in the PRA and have F-V values of zero. Therefore, unreliability data reported for these valves do not get counted in the MSPI calculation.

- Emergency Operating Procedure E-0, Step 8, has an action to close MV-32115, "Component Cooling Water Supply to the Spent Fuel Pool Heat Exchanger." The USAR indicates that a component cooling train could fail due to excessive flow if the valve is not closed. The licensee did not include this valve as an active component but agreed during the inspection that it should be included.

- For EAC, the cross-tie breakers from the other unit are modeled in the PRA and have a large effect on the F-V values for the emergency diesel generators. However, the licensee did not include the cross-tie breakers as active components. According to NEI 99-02, the breakers should be included as active components since they are in the PRA. Licensee engineers stated during the inspection that they intend to add the breakers as active components. However, NEI 99-02, Draft Appendix F, Table 2, does not have industry information for breakers, and they are not listed as one of the component types to choose from in the MSPI spreadsheet. In order to add these active components, the NEI spreadsheet will have to be revised.

- The licensee did not document why the safety injection accumulator discharge valves were not included as active components although the Emergency Operating Procedures direct that they be closed during certain accidents.

- For the high pressure safety injection (SI) system, valves, such as MV-32202, were included as active components but are not in the PRA. F-V values were assigned that the licensee PRA engineers say are conservative, but they did not make similar assignments for other valves without F-V values. The licensee should justify why number is conservative, and possibly apply the same technique to other valves like CV-31381 discussed above. During the inspection, the licensee stated that they will consider assigning conservative F-V values to all active components not modeled in the PRA.

- The licensee's PRA model assumed the A train CC pump and both non-safety CL pumps were continuously running. Since the model assumed they were running, there was no unavailability F-V importance factor for them. Thus any unavailability data for those pumps do not get counted in the MSPI calculation. However, the licensee reported unavailability hours for those pumps. Unavailablity hours for the pumps assumed to be running in the PRA should be assigned to the pumps assumed to be in standby so that they get counted in the MSPI calculation, or appropriate unavailability F-V values should be assigned to the pumps. The licensee's PRA engineer stated that this issue would be reviewed.

03.05 Train/Segment Unavailability Boundary Definition

- The licensee did not specify electrical boundaries. NEI 00-02 guidance stated that the last breaker or relay for electrical power and controls should be in the boundaries for pumps and valves.

03.06 Entry of Baseline Data - Planned Unavailability

- The licensee's calculation for subtracting unplanned unavailability from total unavailability to get just the planned hours had a discrepancy in that some cascading unplanned unavailability hours were more than the total unplanned unavailability hours for the train. This resulted in errors in the baseline planned unavailability. Licensee engineers found the source of the error during the inspection.

03.07 Entry of Baseline Data - Unplanned Unavailability

- No discrepancies were noted. Correct table values were used.

03.08 Entry of Base line Data - Unreliability

- No discrepancies were noted. Correct table values were used.

03.09 Entry of Performance Data - Unavailability

- The inspectors sampled data reported for the 2nd quarter 2002 for CC and CL and the 3rd quarter 2002 for AFW for the current performance index and also sampled data for the 3rd quarter 2000 for AFW and 4th quarter 2000 for CC and CL for verification of historic values.

- No discrepancies were identified in AFW unavailability data for the 3rd quarter 2002.

- The licensee made a small error in the reported unavailable time for the 22 CC train when there was a problem with the 22 CC heat exchanger temperature control valve, CV-31384, on May 5-6, 2002. Licensee engineers found the source of the error during the inspection.

- No discrepancies were noted in the CL unavailability for the 2nd quarter 2002.

- The inspectors identified errors in the reported data for unavailability of AFW for the 3rd quarter 2000 for all except the 12 AFW pump. Licensee engineers later identified that some unavailable time had been double counted.

03.10 Entry of Performance Data - Unreliability

The inspectors sampled data from the 2nd quarter 2002 for CC and CL and the 3rd quarter 2002 for AFW for current performance and also sampled data for the 3rd quarter

2000 for AFW and 4th quarter 2000 for CC and CL for verification of historic values. The inspectors also performed a very limited sampling of data for other systems.

- For the AFW, SI, and RHR systems, the licensee estimated pump start demands, run times, and valve stroke demands based on normal surveillance schedules. The licensee did not provide auditable records of how those estimated were obtained.

- The inspectors noted that the licensee reported one start demand for each RHR pump during the 2nd quarter 2002. According to the electronic control room log and process book, there were two demands on the 22 RHR pump. This was one example of an error due to estimating start demands and run times based only on the number of surveillance tests that are typically done.

- The licensee reported the correct number of start demands for the 11 and 12 CC pumps for the 2nd quarter 2002. However, the inspectors identified that one of the starts on each of the pumps was a post-maintenance test (PMT). In general, the licensee did not eliminate PMTs from reported start demands for most systems.

- The inspectors identified that the run hours reported for the 11 CC pump were 24 hours short for the 2nd quarter 2002. Licensee engineers found the source of the error during the inspection.

- The licensee reported seven starts for each of the 21 and 22 CC pumps in the 2nd quarter 2002. However, the inspectors determined that one of the starts on the 21 CC and two of the starts on the 22 CC were PMTs and should not have been counted.

- The inspectors identified that the licensee did not report the May 2, 2002, trip of the 22 CL pump as a start demand failure (it was running less than an hour). The trip was due to a spurious overspeed trip due to radio interference. The trip happened during a surveillance test but took more than a trivial amount of time to diagnose. The inspectors determined that the trip should have been considered a start demand failure. During the inspection, the licensee agreed to count it as a failure.

- The licensee reported six start demands on the 22 CL pump during the 3rd quarter 2002. The inspectors could only identify four. During the inspection, the licensee found the source of the error.

03.11 <u>MSPI Calculation</u>

- Some of the MSPI F-V coefficients were not verified because the licensee had not identified all of the F-V coefficients due to certain components not being modeled in their PRA (as noted in Section 03.04) or the F-V coefficient was truncated out at a 1E-10 value. Specific components with no F-V value due to truncation include:

- Units 1 and 2 CC heat exchanger outlet valves, MV-32120, MV-32121, MV-32122, and MV-32123;
- Units 1 and 2 Turbine Building Loop A/B Cooling Water Header Valves, MV-32031 and MV-32033;
- Units 1 and 2 SI pump suction valves, MV-32163 and MV-32191;
- Units 1 and 2 SI test to refueling water storage tank isolation valves, MV-32202, MV-32203, MV-32204, and MV-32205;
- Units 1 and 2 Bus 15 to Bus 25 tie breaker, 15-8; and
- Units 1 and 2 Bus 25 to Bus 15 tie breaker, 25-17.

- The NRC staff has not qualified the licensee’s PRA.