UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

May 14, 2013

Mr. Jim Lynch
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2013002;
05000306/2013002; AND 07200010/2013001

Dear Mr. Lynch:

On March 31, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed inspection report documents the inspection results which were discussed on April 11, 2013, with you and other members of your staff.

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

Six NRC identified findings and one self-revealed finding of very low safety significance (Green) were identified during this inspection. These findings were determined to involve violations of NRC requirements. Additionally, the NRC has determined a Severity Level IV violation occurred. This traditional enforcement violation was associated with one of the NRC identified findings. Further, licensee-identified violations which were determined to be of very low safety significance are listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy.

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

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room)..

Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

Docket Nos. 50-282; 50-306; 72-010
License Nos. DPR-42; DPR-60; SNM-2506

Enclosure: Inspection Report 05000282/2013002; 05000306/2013002; and 07200010/2013001
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306; 72-010
License Nos:	DPR-42; DPR-60; SNM-2506
Report No:	05000282/2013002; 05000306/2013002; and 07200010/2013001
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	January 1 through March 31, 2013
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector T. Bilik, Engineering Inspector J. Bozga, Engineering Inspector A. Dunlop, Senior Engineering Inspector M. Holmberg, Senior Engineering Inspector M. Learn, Independent Spent Fuel Storage Installation Inspector C. Moore, Operator Licensing Examiner D. Passehl, Senior Reactor Analyst M. Phalen, Senior Health Physicist
Approved by:	Kenneth Riemer, Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000282/2013002; 05000306/2013002; 07200010/2013001, 01/01/2013 – 03/31/2013; Prairie Island Nuclear Generating Plant, Units 1 and 2; Flooding Protection, Surveillance Testing, Performance Indicators, and Event Followup.

This report covers a 3-month period of inspection by resident inspectors, announced baseline inspections by regional inspectors, and an inspection of the independent spent fuel storage installation (ISFSI). Seven Green findings were identified by the inspectors. The findings were considered non-cited violations (NCVs) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross Cutting Areas" dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," on February 4, 2013, due to the licensee's failure to follow procedures for material storage near a Unit 2 Turbine Building critical drainage path. Specifically, ten drums were not secured in accordance with Section 6.2.11 of Procedure 5AWI 8.9.0, "Internal Flooding Drainage Control." Corrective actions for this issue included removing the material and providing training to personnel on internal flooding drainage control requirements.

  The inspectors determined that this finding was more than minor because if left uncorrected the unsecured material could become buoyant, impede water drainage, and impact the function of safety-related equipment following an internal flood. This finding was of very low safety significance because each question listed in IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions," was answered "no." This finding was cross-cutting in the Human Performance, Work Control area because the licensee failed to keep personnel appraised of the operational impact of work activities and plant conditions that may affect work activities H.3(b). (Section 1R06.1)

- Green. The inspectors identified a finding of very low safety significance and an non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," on December 29, 2012, due to the failure to correct a condition adverse to quality. Specifically, the licensee failed to correct safety injection (SI) accumulator check valve SI-6-4 after the valve failed surveillance testing. Corrective actions for this issue included performing an operability evaluation which determined that SI-6-4 was operable but nonconforming, scheduling the testing of SI-6-4 for the next refueling outage, and performing an extent of condition review.

The inspectors determined that that this issue was more than minor because if left uncorrected the failure to correct conditions adverse to quality could become a more significant safety concern due to safety-related equipment issues being unresolved. This issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no." The inspectors concluded that this issue was cross cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee did not thoroughly evaluate the problems with SI-6-4 to ensure that the resolution addressed the cause P.1(c). (Section 1R22.1b.(1))

- Green. The inspectors identified finding of very low safety significance and an non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," on January 28, 2013, due to the failure to have instructions appropriate to the circumstance to address the presence of foreign material in the new D2 emergency diesel generator (EDG) air start piping assembly. This resulted in the D2 EDG failing to start during monthly surveillance testing. Corrective actions for this issue included removing the foreign material from the piping assembly and inspecting the remaining D1 and D2 EDG air start piping assemblies for cleanliness.

  The inspectors determined that this issue was more than minor because if left uncorrected, the presence of foreign material in safety-related components could lead to a more significant safety concern. Specifically, foreign material could migrate into various areas and render safety-related equipment inoperable. The inspectors determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no" due to the ability to start the D2 EDG using the remaining air start "train" and the lack of foreign material in this portion of the D2 EDG starting air system. The inspectors determined that this issue was cross cutting in the Problem Identification and Resolution, Operating Experience area because the licensee had not institutionalized the operating experience regarding solenoid valve sticking due to foreign material through changes to station processes, procedures, equipment and training programs P.2(b). (Section 1R22.1b.(3))

- Green. The inspectors identified a finding of very low safety significance and an non-citied violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to establish measures for the selection and review for suitability of application of parts that are essential to the safety-related functions of structures, systems and components (SSC). Specifically, the licensee failed to ensure that the D5 and D6 EDG radiator fan motor thermal overload heaters were sized in accordance with Procedure H6.3, "General Electric Thermal Overload Heater Sizing for Non-Motor Operated Valve Motors." This resulted in the D6 EDG becoming inoperable due to Fan #2 on Engine #1 tripping during surveillance testing conducted on December 17, 2012.

  This issue was determined to be more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone. In addition, this issue impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2 was answered "no." The

inspectors determined that this issue was cross cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee did not take appropriate corrective actions to address safety issues in a timely manner commensurate with their safety significance and complexity P.1(d). (Section 1R22.1b.(4))

- Severity Level IV. The inspectors identified a Severity Level IV non-citied violation of 10 CFR Part 50.9, "Completeness and Accuracy of Information," and an associated finding of very low safety significance (Green) due to the licensee's failure to provide information to the Commission that was complete and accurate in all material respects. Specifically, the licensee failed to follow procedures to ensure that the Mitigating Systems Performance Index (MSPI) for the emergency alternating current power systems was accurately reported for the third and fourth quarters of 2012. Once the information inaccuracies were corrected, the Unit 2 MSPI performance indicator (PI) changed from green to white. Corrective actions for this issue included correcting the inaccurate information, assigning dedicated resources to manage the PI reporting process, and performing an extent of condition review to ensure that the remaining PIs were appropriately reported.

  This issue was determined to be more than minor because it was related to a PI and caused the PI to exceed a threshold. This finding was evaluated for significance using IMC 0609, Appendix M, because the other SDP methods and tools were not adequate to determine the significance of the finding. After consulting with NRC management, the inspectors determined that this finding was of very low safety significance because the actual time the PI was inaccurately reported was short and the reporting inaccuracies had no impact on the ability of safety related equipment to perform its safety function. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the inaccurate reporting was caused by a failure to follow procedures H.4(b).

  The violation of 10 CFR Part 50.9 impacted the ability of the NRC to perform its regulatory oversight function and was determined to be Severity Level IV based upon Example 6.9.d.11 of the NRC Enforcement Policy. (Section 4OA1.5)

- Green. The inspectors identified a finding of very low safety significance and an non-citied violation of 10 CFR Part 50, Appendix B, Criterion XVI, on August 14, 2012, due to the licensee's failure to identify and correct a condition adverse to quality. Specifically, the licensee failed to identify and correct a condition of thick smoke resulting from an exhaust manifold oil leak on the D1 EDG; this condition had existed since April 13, 2012. This issue led to an unplanned shutdown of the Unit 1 reactor due to the discovery of a similar condition on the D2 EDG. Corrective actions included completing an equipment cause evaluation and replacing the EDG exhaust manifold gaskets and bolting.

  The inspectors determined the finding was more than minor because, if left uncorrected, the failure to promptly identify and correct conditions adverse to quality could become a more significant safety concern. Specifically, the failure to identify and correct emergency diesel generator oil leaks could lead to a fire hazard and the unavailability of safety-related equipment. A Senior Reactor Analyst determined that this finding was of very low safety significance because the overall change in core damage frequency due

to this issue was 3.3E-7/yr. The inspectors determined the finding was cross-cutting in the Problem Identification and Resolution, Operating Experience area because of the licensee's failure to implement and institutionalize operating experience through changes to station processes, procedures, equipment, and training programs P.2(b). (Section 4OA3.1)

Cornerstone: Barrier Integrity

- Green. A self-revealed finding of very low safety significance and an non-citied violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred on March 19, 2013, due to the licensee's failure to follow Procedure 5AWI 3.10.1, "Methods of Performing Verifications." Specifically, Appendix A of Procedure 5AWI 3.10.1 required that concurrent verification be performed for any action involving circuits that were opened at fuses or sliders. The failure to perform concurrent verification during the removal of a fuse during clearance order activities resulted in the incorrect fuse being removed which rendered a containment isolation valve inoperable. Corrective actions for this issue included re-installation of the fuse and returning the containment isolation valve to service. The licensee was developing additional actions to address the performance of the operators at the conclusion of the inspection period.

  The inspectors determined that this finding was more than minor because if left uncorrected, the failure to properly conduct verification activities could become a more significant safety concern. This finding was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," was answered "no." The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the licensee failed to assure human error prevention techniques were used such that work activities were performed safely H.4(a). (Section 1R22.1b.(2))

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's corrective action program (CAP). These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period in power ascension following Refueling Outage 1R28. Upon achieving full power levels, Unit 1 operated at, or near, full power for the remainder of the inspection period. Small reductions in reactor power were completed during the period to allow for required testing of plant equipment.

Unit 2 began the inspection period at full power. On January 19, 2013, operations personnel reduced Unit 2 reactor power to perform condenser tube cleaning. Unit 2 returned to full power following the cleaning activities. Small reductions in reactor power were completed during the period to allow for required testing of plant equipment.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 122 Control Room Chiller;
- 12 Control Rod Drive Motor Generator; and
- D6 Emergency Diesel Generator (EDG).

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Safety Analysis Report (USAR), Technical Specification (TS) requirements, outstanding work orders (WOs), corrective action reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable.
The inspectors examined the material condition of the components and observed equipment operating parameters to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the Corrective Action Program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04-05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On February 16, 2013, the inspectors performed a complete system alignment inspection on accessible portions of the 12 Diesel Driven Cooling Water Pump and the "A" Cooling Water Header to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on the availability, accessibility, and condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone 2 – Auxiliary Feedwater Pump Room;
- Fire Zone 4 – Unit 1 695' Elevation of the Turbine Building (NFPA [National Fire Protection Association] 805 High Risk Alternate Compensatory Measure);
- Fire Zone 12 – Relay Room;
- Fire Zone 15 – Unit 1 715' Elevation of the Turbine Building (NFPA 805 High Risk Alternate Compensatory Measure);

- Fire Zone 37 – Unit 2 695' Elevation of the Turbine Building (NFPA 805 High Risk Alternate Compensatory Measure); and
- Fire Zone 44 – Unit 2 715' Elevation of the Turbine Building (NFPA 805 High Risk Alternate Compensatory Measure).

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the licensee's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the licensee's ability to respond to a security event. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

On February 4, 2013, the inspectors performed a walkdown to evaluate the licensee's continued implementation of turbine building internal flooding compensatory measures instituted in 2009. The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding. The inspectors also reviewed the licensee's corrective action documents with respect to past internal flooding related items identified in the CAP to verify the adequacy of the corrective actions.

Documents reviewed are listed in the Attachment to this report. This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and a non-citied violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," on February 4, 2013, due to the failure to implement requirements for the control of material near a critical drainage path. Specifically, ten drums were not secured in accordance with Section 6.2.11 of Procedure 5AWI 8.9.0, "Internal Flooding Drainage Control."

Description: During a walkdown of the Unit 2 Turbine Building on February 4, 2013, the inspectors observed ten 55-gallon drums tied off to a structural member with a single rope near the Unit 2 Turbine Building roll-up door. In April 2009, the licensee implemented several compensatory measures as part of a turbine building internal flooding operability concern. These measures included opening both turbine building roll-up doors approximately 16 inches to allow water from an internal flooding event to escape the turbine building. The licensee also revised Procedure 5AWI 8.9.0 to incorporate specific requirements for the control of material within critical drainage paths or near the turbine building roll-up doors. Specifically, Procedure 5AWI 8.9.0 stated the following:

- drainage paths were to remain clear of obstructions that might impede drainage flow;
- materials that could float in, or be swept to, the roll-up door areas by 12 inches of water must be fixed in place when not in use;
- individual items must be tethered to structural members to prevent movement; and
- multiple items must be tethered together with tied netting and secured to a structural member to prevent movement.

The inspectors determined the ten 55-gallon drums were not secured in accordance with 5AWI 8.9.0, Section 6.2.11.c.6 requirements. The inspectors discussed the issue with the Unit 2 Control Room Supervisor. The supervisor confirmed that the method used to tether the drums did not meet 5AWI 8.9.0 procedural requirements.

Analysis: The inspectors determined the failure to properly control material that could impede critical drainage path flow and impact the operation of safety-related equipment following an internal flood was a performance deficiency that impacted the Mitigating Systems Cornerstone and required evaluation using the Significance Determination Process (SDP).

The inspectors determined the finding was more than minor because if left uncorrected the unsecured material could become buoyant, impede water drainage, and impact the function of safety-related equipment following an internal flooding. Specifically, the failure to properly secure ten 55-gallon drums presented a challenge to a critical drainage path used to ensure the availability of safety-related equipment during specific initiating events.

The inspectors utilized IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," and concluded that the significance of this finding be determined using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power."

The inspectors determined that this finding was of very low safety significance because each question listed in Inspection Manual Chapter (IMC) 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no." The inspectors determined that this finding was cross-cutting in the Human Performance, Work Control area because of the licensee's failure to keep personnel appraised of the operational impact of work activities and plant conditions that may affect work activities (H.3(b)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be accomplished in accordance with instructions, procedures, and drawings.

Procedure 5AWI 8.9.0 established drainage and process control requirements necessary to maintain equipment operable during an internal flood. Section 6.2.11.a.1 designated the turbine building roll-up doors as critical drainage paths when the respective unit was in Modes 1 through 4.

Section 6.2.11.c.3 required drainage paths to remain clear of obstructions (i.e. stored/staged material) that might impede drainage flow.

Section 6.2.11.c.4 specified material that could float in 12 inches of water, or be swept to the door by 12 inches of flowing water, be fixed in place when not in use.

Lastly, to be fixed in place, Section 6.2.11.c.6 required tethering individual items to structural members, adding weight to the item so it would not float, or firmly grouping individual items together with tied netting and tethering as a group to a structural member.

Contrary to the above, on February 4, 2013, an activity affecting quality was not accomplished in accordance with Section 6.2.11 of Procedure 5AWI 8.9.0. Specifically, ten 55-gallon drums were not tethered together to a structural member with tied netting. In addition, weight was not added to the drums to ensure that the drums would not be swept away by 12 inches of water. As a result, the material potentially challenged a critical drainage path established for the protection of engineered safety systems from internal turbine building flooding consequences.

Because this violation was of very low safety significance, and it was entered into the licensee's corrective action program as CAPs 1368845 and 1374550, this violation is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000306/2013002-01; Potential for Critical Drainage Path Blockage due to Improper Material Storage)**. Completed corrective actions included removing the material and providing training to personnel on internal flooding drainage control procedure requirements.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On January 15, 2013, the inspectors observed a crew of licensed operators in the simulator during training to verify that operator performance was adequate, evaluators

were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On January 19, 2013, the inspectors observed control room operators perform a planned Unit 2 power reduction. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of procedures;
- control board manipulations; and
- oversight and direction from supervisors.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- 11 Control Rod Drive Motor Generator Set and
- Anticipatory Mitigating System Actuation Circuitry.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR Part 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR Part 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Emergent work on the Bus 26 Load Sequencer;
- Emergent work on the 11 Shield Building Ventilation System;
- Planned maintenance on Transformer CT-11;
- Emergent work on the D1 EDG; and
- Planned maintenance on the 21 Shield Building Ventilation System.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR Part 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

Documents reviewed are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- CAP 1364224 – Impact of Higher than Normal Condensate Storage Tank Temperatures on Auxiliary Feedwater Pump Operability;
- CAP 1366645 – Received Alarm on Seismic Monitoring Panel;
- CAP 1367286 – Procedure G1 Does Not Credit a Specific Procedure for Surveillance Requirement 3.4.16.2;
- CAP 1368044 – D2 Failed to Start and Locked Out during SP 1305;

- Engineering Change 21360 – Inservice Testing of SI-6-3 and SI-6-4 as Series Check Valves in lieu of Testing Each Check Valve Individually;
- Operability Recommendation (OPR) 1364709 – Operability of Safety Injection Accumulator Check Valve SI-6-4 Following a Surveillance Test Failure; and
- OPR 1365473 – Operability of Multiple Pressure Isolation Valves Following the Identification That Valves Were Not Properly Tested.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and the USAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

This operability inspection constituted seven samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Bus 26 Load Sequencer return to service testing following relay replacement;
- 22 Shield Building Ventilation return to service testing;
- D1 and D2 EDG return to service testing follow air start piping foreign material concerns;
- D1 EDG return to service testing following governor hunting concerns;
- D2 EDG return to service testing following erratic speed switch output concerns;
- 22 Diesel Driven Cooling Water Pump return to service testing following planned maintenance;
- D2 EDG return to service testing following increased frequency concerns; and
- 12 Diesel Driven Cooling Water Pump return to service following planned maintenance.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems, entering them in the CAP, and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted eight post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- SP 1028B – Radiation Monitor Monthly Source Check (reactor coolant system leakage detection);
- SP 1094 - Bus 15 Load Sequencer Testing (routine);
- SP 1103 – 11 Turbine Driven Auxiliary Feedwater Pump Test (inservice testing);
- SP 1269 – Safety Injection Accumulator Check Valves Refueling Leak Test (reactor coolant system leak detection);
- SP 1305 – D2 Diesel Generator Monthly Slow Start (routine);
- SP 2095 - Bus 26 Load Sequencer Testing (routine);
- SP 2285 – Containment Isolation Valves For Reactor Coolant Drain Tank to Gas Analyzer Quarterly (containment isolation valve);
- SP 2305 – D6 Diesel Generator Monthly Slow Start (routine); and
- Unit 1 Containment Fan Coil Inspection due to humidity concerns (containment isolation valve).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers (ASME) code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples, one inservice testing sample, two reactor coolant system leak detection inspection samples, and two containment isolation valve samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

(1) Failure to Correct Valve SI-6-4 After It Failed Surveillance Testing

Introduction: The inspectors identified a finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," due to the failure to correct a condition adverse to quality. Specifically, the licensee failed to correct safety injection (SI) accumulator check valve SI-6-4 after the valve failed surveillance testing on December 28 and 29, 2012.

Description: On December 28, 2012, the licensee completed SP 1269, "SI Accumulator Check Valves Refueling Leak Test." This test measured the leakage through two in series check valves to ensure that the 11 SI accumulator was protected from over pressurization by the reactor coolant system (RCS). During the testing, SI accumulator check valve SI-6-4 indicated a leakage rate of greater than 15 gallons per minute (gpm) when reactor pressure was approximately 900 pounds per square inch gauge (psig). After completing testing on SI-6-4, the licensee performed the same leakage test on check valve SI-6-3. Testing performed on SI-6-3 showed that this valve exhibited zero leakage. Since at least one of the two check valves exhibited leakage less than the 3.17 gpm acceptance criteria, the licensee determined that the 11 SI accumulator was adequately protected from over pressurization. However, SI-6-4 was required to be tested when the Unit 1 reactor reached normal operating pressure and temperature to ensure that all inservice testing (IST) requirements were met. In addition, the licensee believed that the higher reactor pressure would assist in fully closing SI-6-4.

Over the next 24 hours, operations personnel completed the actions needed for Unit 1 to reach normal operating temperature and pressure. Immediately following this achievement, the licensee tested SI-6-4 using SP 1070, "Reactor Coolant System Integrity Test." During this test, the licensee estimated the leakage across SI-6-4 as 41 gpm. Since this leak rate exceeded the acceptance criteria within SP 1070, the licensee declared SI-6-4 inoperable.

On December 30, 2012, engineering personnel approved Engineering Evaluation EC-21360, "Inservice Testing of SI-6-3 and SI-6-4 as Series Check Valves in Lieu of Testing Each Check Valve Individually." The licensee used this evaluation as a basis for concluding that SI-6-3 and SI-6-4 could be tested as a valve pair rather than as two individual valves. When the licensee initially wrote the evaluation, engineering personnel believed that the check valves were classified as Category B/C valves under the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code). The ASME OM Code defined Category B/C valves as check valves for which seat leakage in the closed position was inconsequential. The evaluation stated that ASME OM Code, Subsection ISTC-5223, "Series Valve Pairs," allowed Category B/C check valves installed in a series configuration to be tested as a valve pair as long as provisions did not exist to test the valves individually and the USAR only assumed closure of one valve to complete the safety function. Based upon the information provided in ISTC-5223, and the fact that SI-6-3 exhibited zero leakage, the licensee concluded that SI-6-3 and SI-6-4 were operable. The licensee documented this operability conclusion in CAP 1364709.

A short time later, the licensee approved another evaluation which allowed for mechanically agitating SI-6-4. The inspectors discussed concerns regarding the mechanical agitation and the potential for preconditioning SI-6-4 with a senior licensee manager. The licensee believed that the agitation was acceptable and did not constitute preconditioning because SI-6-4 had been declared operable. The licensee measured the internal leakage across SI-6-4 following the mechanical agitation and found that the combined leakage through SI-6-3 and SI-6-4 was less than the acceptance criteria specified in SP 1070.

The NRC began reviewing EC-21360 on December 31, 2012. Initially, the inspectors were concerned about the licensee's statement that SI-6-3 and SI-6-4 could not be tested individually. This concern was developed based upon the fact that the licensee had been individually testing these valves for several years. The only change that had occurred was that the licensee had refurbished both of the SI check valves during Refueling Outage 1R28.

The following day, the licensee discovered that their response to Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," contained a commitment to the NRC to treat SI-6-3 and SI-6-4 as Category A valves. The ASME OM Code defined Category A valves as valves for which seat leakage was limited to a specific maximum amount in the closed position for fulfillment of their required function. However, the licensee continued to believe that the conclusions provided in EC-21360 applied to Category A valves.

On January 4, 2013, the NRC held discussions with the licensee regarding EC-21360. The NRC informed the licensee that the logic provided in the EC was flawed based upon the following:

- ISTC-5223 applied only to check valve exercising and not check valve leakage testing;
- ISTC-5223 applied to series check valves that did not have individual test provisions. Since the licensee had tested these valves individually for several years, and the plant design had not changed, there was no basis for suddenly concluding that the testing provisions no longer existed;
- ISTC-5223 applied to designs where only one valve in the pair was required to close. Due to the discovery that SI-6-3 and SI-6-4 were Category A pressure isolation valves, Paragraph 4.1.1 of NUREG-1482, Revision 1, required that each pressure isolation valve be tested individually.

The NRC determined that since the justification provided in EC-21360 was flawed, the operability discussion provided in CAP 1364709 was also incorrect.

During an additional review, the inspectors found that the licensee had failed to take corrective actions to address the condition of SI-6-4 as discussed in Subsection ISTC-3630(f) of the ASME OM Code and Procedure FP-OP-OL-01, Attachment 2, "Guidelines for Operability Recommendations." Both of these documents stated that if a valve's IST results indicated that a valve had degraded to an unacceptable condition, then it shall be immediately declared inoperable until the cause of the condition is determined and corrected. In addition, Criterion XVI of 10 CFR Part 50, Appendix B, required conditions adverse to quality be promptly

identified and corrected. According to NSPM-1, "Northern States Power-Minnesota Quality Assurance Topical Report," a condition adverse to quality was defined as a(n) failure, malfunction, deficiency, deviation, abnormal occurrence, nonconformance, defective material or equipment, or an out-of-control process, including a failure to follow procedures. The inspectors concluded that although the licensee declared SI-6-4 inoperable following testing on December 29, 2012, the failure of SI-6-4 to meet surveillance procedure acceptance criteria was a condition adverse to quality which was not corrected.

On January 9, 2013, the licensee completed OPR 1364709-04 to document why the 11 SI accumulator and SI-6-4 continued to be operable. The licensee determined that the 11 SI accumulator was operable because it was able to perform its safety function of introducing borated water into the reactor core following a loss of coolant accident. However, SI-6-4 was determined to operable but nonconforming because although the leakage across SI-6-4 was reduced, the mechanical agitation constituted unacceptable preconditioning. As a result, the reduced leakage amount could not be used to demonstrate that SI-6-4 had been appropriately tested as required by the ASME OM Code. The licensee determined that SI-6-4 was also nonconforming due to the failure to complete the corrective actions required by ISTC-3630(f).

Analysis: The inspectors determined that the failure to correct the condition adverse to quality associated with SI-6-4 was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because if left uncorrected the failure correct conditions adverse to quality could become a more significant safety concern. Specifically, this type of action could result in long-term degradation of and/or nonconforming safety-related equipment.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and concluded that this issue was associated with the Mitigating Systems Cornerstone. The inspectors determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no." Specifically, this finding did not result in a loss of the 11 SI accumulator because SI-6-3 provided adequate over pressure protection. In addition, previously performed testing adequately demonstrated that SI-6-3 and SI-6-4 would open to allow the contents of the 11 SI accumulator to inject borated water into the RCS following a loss of coolant accident. The inspectors determined that this issue was cross cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee did not thoroughly evaluate the problems with SI-6-4 to ensure that the resolution addressed the cause P.1(c).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that conditions adverse to quality, such as failures and nonconformances, be corrected.

Contrary to the above, on December 29, 2012, the licensee failed to correct a condition adverse to quality. Specifically, SI accumulator check valve SI-6-4 failed its surveillance test and the licensee did not take action to correct it prior to returning the valve to service and instead relied upon another valve in series to provide leak tightness for the system.

These actions did not meet the ASME Category A pressure isolation valve requirements specified in Section ISTC-3630(f) of the ASME OM Code.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAPs 1364709 and 1378318, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2013002-02: Failure to Correct Condition Adverse to Quality on SI-6-4)**.

Corrective actions for this issue included performing an extent of condition review to assure that other valves were being appropriately tested as required by the ASME OM Code (see Section 4OA7 of this report for additional details). The licensee also planned to test SI-6-4 during the next refueling outage. The inspectors determined that the failure to properly test SI-6-4 during Refueling Outage 1R28 was not an immediate safety concern because actions taken following the surveillance test failure resulted in lowering the leakage past SI-6-4, the 11 SI accumulator was protected against over pressurization, and other testing demonstrated that SI-6-3 and SI-6-4 would open to allow the 11 SI accumulator to inject into the reactor vessel following a loss of coolant accident.

(2) Failure to Follow Procedure Results in Unplanned TS Entry

Introduction: A self-revealed finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," occurred on March 19, 2013, due to the licensee's failure to follow Procedure 5AWI 3.10.1, "Methods of Performing Verifications." Specifically, Step 3 of Appendix A to Procedure 5AWI 3.10.1 required that concurrent verification be performed for any action involving circuits that were opened at fuses or sliders. The failure to perform concurrent verification during fuse removal activities associated with WO 339621 resulted in the incorrect fuse being removed and a containment isolation valve becoming inoperable.

Description: On March 19, 2013, operations personnel performed clearance order activities to support WO 339621. During these activities, a non-licensed operator removed a fuse from Panel 251-13p instead of Panel 251-11p. This action resulted in Control Valve (CV) 31732, "21 Reactor Coolant Drain Tank to 122 Gas Analyzer Isolation Valve," to re-position to its fail safe position. The re-positioning caused an unplanned entry into TS 3.6.3.A which required containment isolation valves to be operable. The operator immediately recognized his mistake and contacted the control room operators to report what had happened.

The licensee initially determined that this event was caused by the non-licensed operator failing to perform a proper verification/validation of the fuse to be removed (a human performance error prevention technique) prior to removing the fuse. A subsequent review determined that a discussion regarding the need for a peer check (another verification/validation technique) just prior to the fuse removal was completed as part of the pre-job brief for the clearance order activity. However, operations personnel decided that a peer check was not needed because the removal of 125 volt fuses was thought to be simple and not complex.

Procedure 5AWI 3.10.1, "Methods of Performing Verifications," established the licensee's requirements regarding the types of verifications needed during specific work activities. Specifically, Step 3 of 5AWI 3.10.1, Appendix A, required that concurrent verification be performed during actions or manipulations involving circuits that are opened at fuses or sliders. The inspectors determined that the clearance order activity performed to support WO 339621 was an action or manipulation that involved a circuit opened at a fuse. However, proper verification of the fuse to be removed was not performed in accordance with the procedural requirements.

Analysis: The inspectors determined the failure to perform verification activities for manipulations involving the removal of fuses as required by 5AWI 3.10.1 was a performance deficiency that was within the licensee's ability to foresee and correct. This finding was more than minor because if left uncorrected, the failure to properly conduct work verification activities could become a more significant safety concern due to the operation of incorrect components or the unintended rendering of safety-related equipment inoperable. The inspectors utilized IMC 0609, Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and concluded that the finding was associated with the Barrier Integrity Cornerstone. This finding was determined to be of very low safety significance because each question contained in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," was answered "no." The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the licensee failed to assure human error prevention techniques were used such that work activities were performed safely (H.4(a)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be accomplished in accordance with instructions, procedures, and drawings appropriate to the circumstance.

Procedure 5AWI 3.10.1, "Methods of Performing Verifications," delineates requirements for methods of performing verifications. Step 3 of 5AWI 3.10.1, Appendix A, required that concurrent verification be performed during actions or manipulations involving circuits that are opened at fuses or sliders. The inspectors determined, in this case, that the removal of fuses was an activity affecting quality since the removal impacted the operability of safety-related equipment.

Contrary to the above, on March 19, 2013, an activity affecting quality was not accomplished in accordance with Step 3 of procedure 5AWI 3.10.1; specifically, the requirements for the verification of manipulations involving circuits that are opened at fuses. As a result, an incorrect fuse was removed which resulted in a containment isolation valve re-positioning and entry into TS 3.6.3.

Because this violation was of very low safety significance, and it was entered into the licensee's corrective action process as CAP 1375245, this violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy
(NCV 05000306/2013002-03: Failure to Follow Procedures during Fuse Removal Activities). Corrective actions for this issue included re-installing the fuse and restoring the containment isolation valve to service. Additional corrective actions regarding operator performance were pending at the conclusion of the inspection period.

(3) Inadequate Work Instructions for Foreign Material Removal Results in D2 Emergency Diesel Generator Failure to Start

Introduction: An inspector identified finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified on January 28, 2013, due to the failure to have instructions appropriate to the circumstance to address the presence of foreign material in the D2 EDG air start piping assembly. This resulted in the D2 EDG failing to start during monthly surveillance testing.

Description: During Refueling Outage 1R28, the licensee took action to replace the D1 and D2 EDG air start piping assemblies due to component obsolescence. Prior to installing the assemblies, the licensee performed quality control receipt inspection activities and identified the presence of foreign material in two specific locations within the assembly that was subsequently installed on the D2 EDG. The licensee initiated CAP 1356631 and Overage, Shortage, Damaged and Discrepant (OSD&D) Report 4792 to document this condition.

The D2 EDG contained two "trains" of air start motors and valves. Under normal conditions, both air start "trains" were in service even though only one "train" was needed to start the EDG. On January 28, 2013, operations personnel performed monthly testing of the D2 EDG using Procedure SP 1305, "D2 Diesel Generator Monthly Slow Start." During testing, SP 1305 directed that one "train" of air start motors and valves be removed from service to allow for the detection of possible failures on the remaining air start train. Immediately upon attempting to start the D2 EDG, operations personnel received both local and control room alarms indicating that the EDG had failed to start due to a problem with the starting air system. Approximately 12 hours later, operations personnel discovered procedural guidance which allowed SP 1305 to be performed using the air start "train" that had been previously removed from service. Once the remaining air start "train" was returned to service, operations personnel completed SP 1305 successfully.

Subsequent troubleshooting of the D2 EDG air start piping assembly identified that foreign material (i.e., pipe thread sealant used by the assembly manufacturer) was present in one or more of the solenoid operators for the D2 EDG air start valves. The presence of the foreign material caused internal components within the solenoid to stick. As a result, the air start valve(s) could not reposition to allow air to enter and start the EDG. The inspectors reviewed CAP 1356631, OSD&D 4792, and WO 422107 and found that instructions were added into WO 422107 to ensure that the previously identified foreign material was removed and that the piping was clear. The inspectors also noted that the licensee had performed at least three successful tests of the EDG after the piping assembly was cleaned and installed. However, neither the inspectors nor the licensee were able to locate engineering evaluations or WO procedure steps which evaluated or removed the potential impacts of the foreign material on the operation of the air start valve solenoid operators. This was noteworthy as industry operating experience existed regarding the sudden failure of the specific type of solenoid valve operators used in the piping assembly due to sticking caused by pipe thread sealant. This also resulted in this issue becoming inspector identified since the licensee had not captured the failure to address the operating experience within the CAP.

Analysis: The inspectors determined that the failure to have appropriate work instructions to ensure that all foreign material was removed from the D2 EDG air start piping assembly prior to installation was a performance deficiency that was within the licensee's ability to foresee and correct. This issue was determined to be more than minor because if left uncorrected, the presence of foreign material in safety-related components could lead to a more significant safety concern. Specifically, foreign material could migrate into SSCs and render safety-related equipment inoperable.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and concluded that this issue was associated with the Mitigating Systems Cornerstone. The inspectors determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no." Specifically, the licensee was able to start the D2 EDG using the remaining air start "train" and no foreign material was found in this portion of the D2 EDG starting air piping assembly during a subsequent inspection. The inspectors determined that this issue was cross cutting in the Problem Identification and Resolution, Operating Experience area because the licensee had not institutionalized the operating experience regarding solenoid valve sticking due to foreign material through changes to station processes, procedures, equipment and training programs (P.2(b)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by instructions, procedures and drawings appropriate to the circumstance and shall be accomplished in accordance with those instructions, procedures and drawings.

Contrary to the above, between October 29, 2012 and January 28, 2013, instructions contained in WO 422107 regarding the removal of foreign material from the D2 EDG air start piping, an activity affecting quality, were not appropriate to the circumstance. Specifically, the instructions failed to address the possibility that foreign material could be present in the solenoid valve operators contained within the D2 EDG air start piping assembly. As a result, pieces of the foreign material within the air start piping solenoid valve(s) caused the D2 EDG to fail to start on January 28, 2013.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAP 1378228, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2013002-04: Inadequate Work Instructions for Removing Foreign Material from D2 EDG Air Start Piping)**. Corrective actions for this issue included removing the foreign material by replacing the solenoid valve and inspecting all other D1 and D2 EDG air start piping assemblies to ensure they were free of foreign material.

(4) Undersized Motor Overload Heaters Render D6 EDG Inoperable

Introduction: The inspectors identified a finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to establish measures for the selection and review for suitability of application of parts that are essential to the safety-related functions of SSCs. Specifically, the licensee failed to ensure that the thermal overload heaters for the D5 and D6 EDG radiator fan motors were appropriately sized in accordance with Procedure H6.3, "General Electric

Thermal Overload Heater Sizing for Non-Motor Operated Valve Motors." This resulted in the D6 EDG becoming inoperable due to radiator fan #2 on Engine #1 tripping during monthly EDG surveillance testing.

Description: On December 17, 2012, radiator fan #2 for D6 Engine #1 tripped. Operations personnel immediately declared the EDG inoperable and initiated WO 470367. Subsequent troubleshooting activities included testing and/or inspecting multiple components in an attempt to determine the cause of the fan trip. Although the cause was not clearly identified, the licensee believed that the most likely cause was due to spurious operation of the radiator fan motor overload relay (MOLR). As a result, the licensee replaced the MOLR, operated the fan for approximately 4 hours, and returned the D6 EDG to service.

During the week of March 26, 2013, the inspectors reviewed the results of the licensee's equipment causal evaluation and the historical performance of the D5 and D6 EDG radiator fans. After reviewing this information, the inspectors were concerned that replacing the D6 EDG radiator fan #2 MOLR in December 2012 may not have corrected the condition discussed above. This concern was based upon the following:

- No deficiencies were found during testing of the previously installed MOLR;
- Corrective actions proposed or taken to address the December 2012 radiator fan trip were exactly the same, or similar to, actions taken to address previous fan trips that occurred in 1994 and 2004;
- Previous corrective action information indicated that the radiator fans were being operated at greater than the name plate full load amperage rating during cold weather (this is because current draw increases as air temperature decreases due to the change in air density);
- The bounding fan motor current draw and outside air temperature were unknown; and
- Previous recommended actions to reduce radiator fan current draw, such as changing the fan blade pitch, had not been aggressively pursued.

The inspectors discussed the information provided above with licensee personnel on March 28 and April 1, 2013. The inspectors questioned the appropriateness of the actions based upon a February 2013 CAP (CAP 1371080) which documented radiator fan currents between 70 and 80 amps for approximately one minute and then 63 to 68 amps over the next 24 hours. The inspectors noted that CAP 1371080 contained an action to determine whether the radiator fan MOLR heaters were appropriate sized in April 2013. However, considering the fact that the radiator fan tripping appeared to be temperature dependent and extremely cold outside air temperatures were not likely in April, the inspectors considered the CAP action completion date to be untimely.

On April 2, 2013, engineering personnel initiated CAP 1377245 based upon the inspectors concerns. Specifically, the licensee determined that the fan motor current values recorded in February 2013 were considerably close to the motor overload heater setpoint and that the size of the installed motor overload heater was smaller than what would have been required by Procedure H6.3, "General Electric Thermal Overload Heater Sizing for Non-Motor Operated Valve Motors."

The inspectors reviewed Procedure H6.3 and the information contained in the CAPs initiated following the 1994 and 2004 radiator fan trips. The inspectors found that the licensee had increased the MOLR heater size for the D5 and D6 radiator fans in 1994 based upon the vendor's recommendation. No information was located to determine how the licensee evaluated the acceptability of the vendor's information. In 1995, the methodology for selecting MOLR heater sizes contained in Procedure H6.3 was revised into its current form. Although additional radiator fan trips occurred, the inspectors were unable to find any information indicating that the licensee had considered the possibility that undersized MOLR heaters had caused the 2004 and 2012 fan trips.

Analysis: The inspectors determined that the failure to establish design control measures to ensure that the D5 and D6 MOLR heaters were sized as required by Section 3.0 of Procedure H6.3 was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and concluded that this issue impacted the Mitigating Systems Cornerstone. The inspectors determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "no." Specifically, this issue did not affect the design of the EDG ventilation system nor did it result in a loss of safety function for greater than the TS allowed outage time. The inspectors determined that this issue was cross cutting in the Problem Identification and Resolution, CAP area because the licensee did not take appropriate corrective actions to address safety issues in a timely manner commensurate with their safety significance and complexity (P.1(d)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established for the selection and review for suitability of application of parts that are essential to the safety-related functions of SSCs. The licensee used Procedure H6.3, "General Electric Thermal Overload Heater Sizing for Non-Motor Operated Valve Motors," Section 3.0 to determine and select appropriately sized MOLR heaters.

Contrary to the above, between 1995 and April 2, 2013, measures were not established for the selection and review for suitability of application of parts that are essential to the safety-related functions of SSCs. Specifically, the MOLR heaters installed in the D5 and D6 EDG radiator fans were unsuitable to support the essential function of the safety-related EDGs and resulted in the D6 EDG becoming inoperable on December 17, 2012.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAP 1377245, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2013002-05: Improperly Sized Motor Overload Heaters Rendered D6 EDG Inoperable)**. Corrective actions for this issue included installing properly sized overload heaters for the D5 EDG radiator fans during a planned April 2013 EDG outage and scheduling the D6 EDG radiator fan MOLR heaters for future replacement.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on February 12, 2013, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Simulator and Emergency Offsite Facility to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also reviewed the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff, to verify whether the licensee staff was properly identifying weaknesses, and to determine whether licensee personnel were entering these issues into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings were identified.

.2 Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on January 15, 2013, which required emergency plan implementation by an operations crew. This evolution was planned to be evaluated and included in performance indicator (PI) data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06-06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation (71124.08)

This inspection constituted one complete sample as defined in IP 71124.08-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the solid radioactive waste system description in the USAR, the Process Control Program (PCP), and the recent Radiological Effluent Release (RER) Report for information on the types, amounts, and processing of radioactive waste disposed.

The inspectors reviewed the scope of any quality assurance audits in this area since the last inspection to gain insights into the licensee's performance and inform the "smart sampling" inspection planning.

b. Findings

No findings were identified.

.2 Radioactive Material Storage (02.02)

a. Inspection Scope

The inspectors selected areas where containers of radioactive waste were stored, and evaluated whether the containers were labeled in accordance with 10 CFR 20.1904, "Labeling Containers," or controlled in accordance with 10 CFR 20.1905, "Exemptions to Labeling Requirements," as appropriate.

The inspectors assessed whether the radioactive material storage areas were controlled and posted in accordance with the requirements of 10 CFR Part 20, "Standards for Protection against Radiation." For materials stored or used in the controlled or unrestricted areas, the inspectors evaluated whether they were secured against unauthorized removal and controlled in accordance with 10 CFR 20.1801, "Security of Stored Material," and 10 CFR 20.1802, "Control of Material Not in Storage," as appropriate.

The inspectors evaluated whether the licensee established a process for monitoring the impact of long term storage (e.g., buildup of any gases produced by waste decomposition, chemical reactions, container deformation, loss of container integrity, or re-release of free-flowing water) that was sufficient to identify potential unmonitored, unplanned releases or nonconformance with waste disposal requirements.

The inspectors selected containers of stored radioactive material and assessed each container for signs of swelling, leakage, and deformation.

b. Findings

No findings were identified.

.3 Radioactive Waste System Walkdown (02.03)

a. Inspection Scope

The inspectors walked down accessible portions of select radioactive waste processing systems to assess whether the current system configuration and operation agreed with the descriptions in the USAR, Offsite Dose Calculation Manual (OCDM), and PCP.

The inspectors reviewed administrative and/or physical controls (i.e., drainage and isolation of the system from other systems) to assess whether equipment which was not in service or abandoned in place would not contribute to an unmonitored release path and/or affect operating systems or be a source of unnecessary personnel exposure. The inspectors assessed whether the licensee reviewed the safety significance of systems and equipment abandoned in place in accordance with 10 CFR Part 50.59, “Changes, Tests, and Experiments.”

The inspectors reviewed the adequacy of changes made to the radioactive waste processing systems since the last inspection. The inspectors evaluated whether changes from what was described in the USAR were reviewed and documented in accordance with 10 CFR Part 50.59, as appropriate and to assess the impact on radiation doses to members of the public.

The inspectors selected processes for transferring radioactive waste resin and/or sludge discharges into shipping/disposal containers and assessed whether the waste stream mixing, sampling procedures, and methodology for waste concentration averaging were consistent with the PCP, and provided representative samples of the waste product for the purposes of waste classification as described in 10 CFR 61.55, “Waste Classification.”

For those systems that provide tank recirculation, the inspectors evaluated whether the tank recirculation procedures provided sufficient mixing.

The inspectors assessed whether the licensee’s process control program correctly described the current methods and procedures for dewatering and waste stabilization (e.g., removal of freestanding liquid).

b. Findings

No findings were identified.

.4 Waste Characterization and Classification (02.04)

a. Inspection Scope

The inspectors selected the following radioactive waste streams for review:

- Bead Resin;
- Dry Active Waste;
- High Level Filters;
- Low Level Filters; and
- Steam Generator Blow Down.

For the waste streams listed above, the inspectors assessed whether the licensee's radiochemical sample analysis results (i.e., "10 CFR Part 61" analysis) were sufficient to support radioactive waste characterization as required by 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste." The inspectors evaluated whether the licensee's use of scaling factors and calculations to account for difficult to measure radionuclides was technically sound and based on current 10 CFR Part 61 analysis for the selected radioactive waste streams.

The inspectors evaluated whether changes to plant operational parameters were taken into account to: (1) maintain the validity of the waste stream composition data between the annual or biennial sample analysis update; and (2) assure that waste shipments continued to meet the requirements of 10 CFR Part 61 for the waste streams selected above.

The inspectors evaluated whether the licensee had established and maintained an adequate quality assurance program to ensure compliance with the waste classification and characterization requirements of 10 CFR 61.55 and 10 CFR 61.56, "Waste Characteristics."

b. Findings

No findings were identified.

.5 Shipment Preparation (02.05)

a. Inspection Scope

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. The inspectors assessed whether the requirements of applicable transport cask certificate of compliance had been met. The inspectors evaluated whether the receiving licensee was authorized to receive the shipment packages. The inspectors evaluated whether the licensee's procedures for cask loading and closure procedures were consistent with the vendor's current approved procedures.

Due to limited opportunities for direct observation, the inspectors reviewed the technical instructions presented to workers during routine training. The inspectors assessed whether the licensee's training program provided training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

b. Findings

No findings were identified.

.6 Shipping Records (02.06)

a. Inspection Scope

The inspectors evaluated whether the shipping documents indicated the proper shipper name; emergency response information and a 24-hour contact telephone number; accurate curie content and volume of material; and appropriate waste classification, transport index, and United Nations number for the following radioactive shipments:

- Shipment Number 11-005 - Class B Resin HIC 139;
- Shipment Number 11-012 - Damaged Fuel Assembly;
- Shipment Number 11-052 - Westinghouse Sipper;
- Shipment Number 12-037 - One (1) New Fuel Bundle; and
- Shipment Number 12-049 - DAW Sealands.

Additionally, the inspectors assessed whether the shipment placarding was consistent with the information in the shipping documentation.

b. Findings

No findings were identified.

.7 Identification and Resolution of Problems (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation were being identified by the licensee at an appropriate threshold, were properly characterized, and were properly addressed for resolution in the licensee's CAP. Additionally, the inspectors evaluated whether the corrective actions were appropriate for a selected sample of problems documented by the licensee that involved radioactive waste processing, handling, storage, and transportation.

The inspectors reviewed results of selected audits performed since the last inspection of this program and evaluated the adequacy of the licensee's corrective actions for issues identified during those audits.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours PI for Prairie Island Units 1 and 2 for the period from the first quarter of 2012 through the fourth quarter of 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, corrective action reports, event reports and NRC Integrated Inspection Reports for the period given above to validate the accuracy of the submittals. The inspectors also reviewed the licensee's corrective action database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned scrams per 7000 critical hours samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI for Prairie Island Units 1 and 2 for the period from the first quarter of 2012 through the fourth quarter of 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, corrective action reports, event reports and NRC Integrated Inspection Reports for the period given above to validate the accuracy of the submittals. The inspectors also reviewed the licensee's corrective action database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned scrams with complications samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Unplanned Transients per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients per 7000 Critical Hours PI for Prairie Island Units 1 and 2 for the period from the first quarter of 2012 through the fourth quarter of 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator narrative logs, corrective action reports, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period given above to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s corrective action database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned transients per 7000 critical hours samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for Unit 1 and Unit 2 for the period from the first quarter of 2012 through the fourth quarter of 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, and NUREG-1022, “Event Reporting Guidelines 10 CFR Part 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the licensee’s operator narrative logs, operability assessments, maintenance rule records, maintenance WOs, corrective action reports, event reports and NRC Integrated Inspection Reports for the period given above to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s corrective action database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two safety system functional failure samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Emergency Alternating Current Power Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency alternating current (AC - Power System PI for Prairie Island Units 1 and 2 for the period from the third quarter of 2012 through the fourth quarter of 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, corrective action reports, event reports and NRC Integrated Inspection Reports for the period given above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's corrective action database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and one issue was identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR Part 50.9, "Completeness and Accuracy of Information," and an associated finding of very low safety significance (Green) due to the licensee's failure to provide information to the Commission that was complete and accurate in all material respects. Specifically, the licensee failed to follow procedures to ensure that the MSPI for the emergency AC power systems was accurately reported for the third and fourth quarters of 2012. Once the information inaccuracies were corrected, the Unit 2 MSPI for the emergency AC power systems changed from green to white.

Description: On January 21, 2013, the licensee reported their fourth quarter 2012 PI information to the NRC. Approximately three days later, NRC headquarters staff requested that the resident inspectors review the licensee's PI information prior to the information being placed on the NRC's public web page. The inspectors found that the color designation for the Unit 1 and Unit 2 MSPI – emergency AC power systems was gray rather than green, white, yellow or red. Under normal conditions, gray was used to indicate PIs that were either not applicable to a specific reactor unit or where insufficient data was available to determine the PI's color.

The inspectors immediately questioned the licensee's performance assessment staff to determine why the PIs were reported as gray. The licensee determined that the PIs were gray because evaluations regarding a common mode failure of the D1 and D2

EDGs from August 2012 and a D6 EDG radiator fan failure from December 2012 were not completed in a timely manner. These equipment issues are discussed in Sections 4OA3.1 and 1R22 of this inspection report. Upon completing these evaluations, the licensee determined that the color of the Unit 1 MSPI – emergency AC power systems PI remained green. However, the D6 EDG radiator fan failure caused the Unit 2 MSPI – emergency AC power systems PI to transition from green to white.

Analysis: The inspectors determined that the failure to provide information to the Commission that was complete and accurate in all material respects was contrary to 10 CFR Part 50.9 and was a performance deficiency that could have and should have been reasonably prevented by the licensee. Specifically, Section 4.3.3 of Procedure H33, "Performance Indicator Reporting," required the following:

- all failures affecting MSPI monitored components be evaluated to determine MSPI impacts;
- all MSPI and/or potential MSPI failures be reviewed by the MSPI Review Board; and
- the data coordinator ensure that failure data was entered into the failure reporting database.

These procedural requirements were not initially met for the failures discussed above. In addition, Procedure H33.2, "Mitigating Systems Cornerstone Unavailability Performance Indicator Reporting Instructions," required that MSPI unavailability and unreliability data be reviewed and validated by additional engineering personnel and senior licensee management. The licensee determined that the review and validation of the MSPI data was not rigorously performed.

In accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that this issue was more than minor because it was related to a PI and caused the Unit 2 MSPI for the emergency AC power systems to change color from green to white. The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings." However, because the existing SDP methods and tools were not adequate to determine the significance of the finding, IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Attributes," was used to determine this finding's significance. After consulting with NRC management, the inspectors determined that this finding was of very low safety significance (Green) because the actual time the PI was inaccurately reported was short and the reporting inaccuracies had no impact on the ability of safety related equipment to perform its safety function **(FIN 05000306/2013002-06: Failure to Provide Accurate Performance Indicator Data)**. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the inaccurate reporting was caused by a failure to follow procedures H.4(b).

The inspectors also determined that the violation of 10 CFR Part 50.9 impacted the ability of the NRC to perform its regulatory oversight function and was subject to traditional enforcement.

Enforcement: Title 10 CFR Part 50.9(a), "Completeness and Accuracy of Information," requires, in part, that information provided to the NRC by all licensees be complete and accurate in all material respects. Contrary to the above, on January 21, 2013, the licensee failed to provide fourth quarter 2012 PI data for the Unit 2 MSPI – emergency AC power systems to the NRC that was complete and accurate in all material respects. Specifically, the licensee failed to include the December 2012 failure of a D6 EDG radiator fan as an MSPI failure. This was material to the NRC, because once the information was corrected, the Unit 2 MSPI performance indicator changed from Green to White. This violation is characterized as a Severity Level IV NCV, consistent with Example 6.9.d.11 of the Enforcement Policy. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAPs 1367890, 1369056, and 1369064, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy
(NCV 05000306/2013002-07: Failure to Provide Accurate Performance Indicator Data). Corrective actions for this issue included submitting the accurate information, providing additional training to personnel responsible for PIs, ensuring the scheduling of PI review boards supported the timely submittal of PI information to the Commission, and performing an extent of condition review to ensure that all remaining PIs were accurately reported.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status activities to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Review of Operations Department's Actions to Address Operator Fundamentals Weaknesses

a. Inspection Scope

On April 5, 2012, the licensee initiated CAP 1332102, "Adverse Trend Noted in Operator Fundamentals," due to four events that were caused by inadequate use of operator fundamental tools. The four events included:

- Reactor Coolant System Drain Down Event;
- Automatic Start of the 11 Component Cooling Water Pump;
- Introduction of River Water into the 21 Steam Generator; and
- Operation of the 12 Boric Acid Transfer Pump without a Discharge Flow Path.

The licensee reviewed each of these events and developed an action plan to improve the overall performance within the Operations Department. During this inspection period, the inspectors reviewed the action plan, discussed the contents of the plan with non-licensed operators, licensed operators, operations management, and operations training personnel, and observed the operators during training and in-plant activities to determine whether the actions contained in the plan had resulted in improved operator performance.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Observations and Findings

No findings were identified. The inspectors determined that the actions taken to date had improved operator performance. However, additional actions were needed to

continue upon the improvement and to demonstrate that the improved performance was sustained. Specific actions taken included:

- Implementation of a tiered decision making process to aid in making conservative decisions during critical times;
- Establishing additional training on operator fundamentals such as teamwork, indication monitoring, and the development of a natural bias for conservative actions;
- Establishing a check operator position to monitor overall performance of the on-shift crew and identify weaknesses in operator fundamentals that needed to be addressed;
- Providing additional coaching on operator fundamentals during the observation of work activities; and
- Establishing a zero tolerance for procedure use and adherence issues.

During targeted observations of control room activities, the inspectors found that the operators actively used the tiered decision making process by involving multiple departments in the decision and documenting the final decision within the control room logs. Integration of operator fundamentals such as team work, high standards for plant operation, indication monitoring, natural bias for conservative decision making, and knowledge were evident during observations of control room turnovers, pre-job briefings, and training. The inspectors also noted that operations personnel demonstrated improved advocacy regarding the resolution of equipment issues.

.4 Selected Issue Follow-Up Inspection: Review of Corrective Actions Taken to Address Valve 2RH-3-2 Material Condition and Testing Methodology Issues

a. Inspection Scope

On February 22, 2012, the licensee initiated CAP 1326085 due to the 21 residual heat removal (RHR) pump suction check valve, 2RH-3-2, failing surveillance testing. The inspectors observed actions taken by the licensee when the test failure occurred to ensure that valve 2RH-3-2 was properly returned to service. However due to the fact that this same valve experienced testing difficulties in 2010, the inspectors chose to perform a more in-depth review of the licensee's causal evaluation and corrective actions by reviewing corrective action documents, reviewing procedure changes and the valve's maintenance work history, and discussing testing methodology changes with operations and engineering personnel.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Observations and Findings

No findings were identified. On May 19, 2010, the licensee initiated CAP 1233577 when the 21 and 22 RHR pump suction check valves failed to meet the acceptance criteria specified in Surveillance Procedure (SP) 2369, "Exercising 21 and 22 RHR Pump Suction Line Check Valves." The licensee immediately declared both RHR trains inoperable due to the surveillance test failure. The licensee determined that the surveillance test failure occurred due to a change in the valve testing methodology. This

change resulted in creating a lower differential pressure across the valves during testing. As a result, the pressure experienced within the piping to assist in closing the check valves was reduced. In response to this event, the licensee revised SP 2369 so that each valve was tested individually. Both valves successfully passed their surveillance test. However, 2RH-3-2 was found to have increased leakage past its seat. The inspectors reviewed the revised testing methodology and the surveillance test results and had no concerns.

On February 22, 2012, the licensee performed SP 2369 as part of Refueling Outage 2R27. During this test, valve 2RH-3-2 failed due to excessive leakage across the valve's seat. The licensee declared the 21 RHR pump inoperable and completed the actions required by TSs. Initially, the inspectors were concerned that valve 2RH-3-2 had failed its surveillance test due to unrecognized testing methodology issues. Subsequent troubleshooting determined that the surveillance test failure occurred due to an internal valve issue rather than a testing issue. The licensee repaired valve 2RH-3-2 and returned the 21 RHR system to service. The inspectors reviewed the licensee's maintenance repair documents, pictures of the as-found condition of the valve, and post-maintenance test results and had no concerns.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Unresolved Item 05000282/2012004-02: Unit 1 Required Shutdown Due to D1 and D2 EDG Exhaust Fires

a. Inspection Scope

As discussed in NRC Inspection Report 05000282/2012004, the inspectors evaluated activities during an unplanned Unit 1 shutdown to effect repairs to the D1 and D2 EDGs due to exhaust manifold fires. Upon the conclusion of that inspection period, the inspectors determined the licensee had not completed its evaluation regarding the cause of the fires. As a result the inspectors were unable to assess whether a performance deficiency existed. During this inspection period, the inspectors reviewed the licensee's causal evaluations for technical adequacy to determine whether a performance deficiency led to the EDG inoperability and the Unit 1 shut down.

This inspection was not counted as an inspection sample due to similarities between it and the activities performed during the closure of Licensee Event Report 05000282/2012-005-00 (see Section 4OA3.2 of this report).

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," due to the failure to identify and correct a condition adverse to quality. Specifically, the licensee failed to correct a condition of thick smoke resulting from an exhaust manifold oil leak on the D1 EDG.

Description: On August 13, 2012, the licensee performed a scheduled monthly surveillance on the D1 EDG. This surveillance resulted in thick smoke and a small fire on the EDG exhaust manifold. Operations personnel immediately shut down the EDG

and declared it inoperable. Subsequent troubleshooting determined that the fire appeared to be caused by an exhaust manifold gasket oil leak at the exhaust extension joint between the ring collector and the turbocharger.

The licensee completed actions to determine whether a common cause failure existed with the remaining operable EDG as required by the TS. On August 14, 2012, the licensee ran the D2 EDG and identified a similar condition where a small fire was present on the exhaust manifold. The D2 EDG was declared inoperable. Since both Unit 1 EDGs were inoperable and the licensee was unable to restore one EDG to operable status within 2 hours, operations personnel were required to shut down the Unit 1 reactor. The licensee documented the D1 fire in CAP 1348004 and the D2 fire in CAP 1348106.

The inspectors reviewed various licensee corrective action documents, causal evaluations, and operating experience related to the EDG fires. On April 13, 2012, the licensee initiated CAP 1333622 to document the presence of thick smoke in the D1 EDG room during surveillance testing. Although the individual initiating the CAP documented a recommendation to repair or modify the exhaust system so that it didn't smoke, the licensee did not take any action on this recommendation. The only licensee action resulting from CAP 1333622 was to evaluate the room air quality during the next engine run. The inspectors found that CAP 1333622 was closed after the licensee determined the room ventilation should adequately remove the smoke. No actions were taken to address exhaust manifold oil leakage as a contributor to the thick smoke. The inspectors also observed operation of the D1 EDG on three separate occasions following the initiation of CAP 1333622. Each time, the inspectors noted continued thick smoke conditions. Operability of the EDGs was not challenged as no fire occurred during these EDG runs. The inspectors discussed their observations with licensee management after each observed EDG run. However, no actions specific to resolving the condition resulted from these discussions.

On January 29, 2009, the licensee initiated CAP 1167382 due to a fire on the exhaust extension to turbocharger insulation during D1 EDG surveillance testing. The inspectors reviewed CAP 1167382 and found that this fire was also preceded by a buildup of smoke and haze in the room. In response to this issue, the licensee completed an apparent cause evaluation (ACE) and determined that oil soaked insulation in conjunction with high exhaust temperatures was the cause of the fire. No action was taken to address the insulation from becoming oil soaked due to the exhaust manifold oil leak.

Information Notice (IN) 2008-05, "Fires Involving Emergency Diesel Generator Exhaust Manifolds" discusses the susceptibility of Fairbanks-Morse Opposed Piston EDGs to exhaust fires that can cause oil to ignite when contact is made with the hot exhaust manifolds. The inspector determined that the IN was applicable to Prairie Island since the Unit 1 EDGs were a similar engine design. The inspectors found that the licensee evaluated the Information Notice in CAP 1138187. The licensee's evaluation focused on mitigating fires rather than correcting them.

The results of the licensee's equipment causal evaluation (ECE) for CAP 1348310 determined the August 2012 fire events were preventable. Specifically, the ECE documented that licensee actions relating to IN 2008-05 were focused on accepting the

condition as being design related and resultant actions were non-conservative for elimination of the issue. The ECE also documented several missed opportunities to identify and correct this condition as part of the causal evaluation performed following the March 2009 EDG fire. Apparent Cause Evaluation 1167382 discussed fires occurring on the exhaust manifolds were preceded by a build-up of smoke and haze in the room. The ACE also discussed how oil passing through leaking exhaust manifold connections can collect in insulation on the exterior of the manifold and ignite when the exhaust gases become hot enough. The missed operating experience opportunities were documented in CAP 1364131.

Analysis: The inspectors determined that the failure to identify and correct a condition adverse to quality with the D1 EDG was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because, if left uncorrected, the failure to promptly identify and correct conditions adverse to quality could become a more significant safety concern. Specifically, the failure to identify and correct emergency diesel generator oil leaks could lead to a fire hazard and the unavailability of safety-related equipment.

The inspectors utilized IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” and concluded that this finding was associated with the Mitigating Systems Cornerstone. In accordance with IMC 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” the inspectors determined that a detailed risk evaluation was needed since a loss of safety function was created when both of the Unit 1 EDGs were rendered inoperable and unavailable to complete repairs.

The Senior Reactor Analyst (SRA) evaluated the finding using the Prairie Island Standardized Plant Analysis Risk (SPAR) external event model and the NRC Risk Assessment Standardization Project (RASP) Handbook. The SRAs determined through discussions with the inspectors and review of licensee records that the exposure time was best defined by the time during which the DGs were inoperable and unavailable. The SRAs performed a condition analysis and initiating event analysis and summed the results to obtain the internal events risk, per the guidance in Section 8.3 of the Handbook. Because the result of the internal events risk was greater than 1E-7/yr, the SRAs also performed an external event analysis, and evaluated large early release frequency (LERF) risk as well.

For the condition analysis, the SRAs calculated the risk assuming that the D1 EDG was unavailable for approximately 26-hours (rounded up) and the D1 and D2 EDGs were unavailable together for approximately 15 hours (rounded up). For the initiating event analysis, the SRA calculated the transient risk of the manual plant shutdown.

Using the SPAR model, the result of the D1 EDG 26-hour unavailability was a change in core damage frequency (ΔCDF) of 6.9E-9/yr. The result of the D1 and D2 EDG combined 15-hour unavailability was a (ΔCDF) of 8.4E-8/yr. The result of the transient analysis was a ΔCDF of 1.0E-7/yr. The total internal events risk was the sum of these three values, or about 2E-7/yr. The dominant risk involved the manual plant shutdown with failures of primary and secondary cooling.

For external event risk, the fire risk contribution was estimated using information from the licensee's Individual Plant Examination for External Events (IPEEE) submitted in October 1998. The contribution to the risk of the finding was limited to fires that cause a loss of offsite power (LOOP). From the Prairie Island IPEEE, there is only one fire initiating event which is postulated to lead to a LOOP. The initiating event is a fire in the control room G-panel. The panel fire frequency is 2.34E-4/yr and is further reduced in the IPEEE by a severity factor of 0.12. Making the conservative assumption that both EDGs were unavailable for the interval between when the first EDG became unavailable and when the last EDG was restored (i.e., a total time of 2416 minutes or 1.68 days), resulted in a delta (ΔCDF) for the fire risk of 1.3E-7/yr.

Seismic risk contributions were screened using the RASP Handbook. Per Appendix 1, Table 1, of Handbook Volume 2, the estimated frequency of seismically-induced LOOP events at Prairie Island is 1.68E-5/yr based on USGS 2008 data (ML11220A1980). This value is orders of magnitude lower than the internal events LOOP frequency. As a result, the seismic risk contributions to this issue were insignificant.

Internal flooding events by themselves were not expected to result in a LOOP initiating event. Thus flooding risk contributions were determined to be insignificant.

The SRA used IMC 0609, Appendix H, "Containment Integrity Significance Determination Process" to determine the potential risk contribution due to LERF. Prairie Island is a 2- Loop Westinghouse PWR with a large dry containment. Sequences important to LERF include steam generator tube rupture events and inter-system loss of coolant accident (LOCA) events. These were not the dominant core damage sequences for this finding and thus the risk significance due to LERF was insignificant.

Based upon the risk information provided above, the SRA determined that the overall risk significance for this finding was 3.3E-7/yr, a finding of very low risk significance (Green).

The inspectors determined that this finding was cross-cutting in the Problem Identification, Operating Experience area because of the licensee's failure to implement and institutionalize operating experience through changes to station processes, procedures, equipment, and training programs (P.2(b)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that conditions adverse to quality, such as deficiencies and nonconformance, are promptly identified and corrected.

Contrary to the above, between April 12, 2012, and August 13, 2012, the licensee failed to promptly identify and correct a condition adverse to quality. Specifically, during an April 12, 2012 D1 EDG surveillance, thick smoke from an exhaust manifold oil leak was noticed. However, the licensee did not promptly identify and correct the exhaust manifold oil leak until an exhaust manifold fire rendered the D1 EDG inoperable on August 13, 2012. Opposite EDG train common cause testing resulted in a similar fire, EDG inoperability, and a TS shutdown of Unit 1 on August 14, 2012, due to both EDGs being declared inoperable.

Because this violation was of very low safety significance, and it was entered into the licensee's corrective action program as CAP 1348310, it is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. (**NCV 05000282/2013002-08: Failure to Correct Condition Adverse to Quality on D1 EDG**). Corrective actions included replacing the EDG exhaust manifold gaskets and bolting and modifying the exhaust insulation to prevent oil from accumulating in the exhaust manifold area.

.2 (Closed) Licensee Event Report 05000282/2012-005-00: Unit 1 Diesel Generators Inoperable due to Exhaust Fire

a. Inspection Scope

On August 17, 2012, the licensee shut down the Unit 1 reactor after discovering that both Unit 1 EDGs were inoperable due to exhaust manifold fires. The inspectors reviewed the operation of both EDGs, observed the exhaust fire locations, discussed EDG material condition with licensee personnel, observed reactor shut down activities, and monitored the licensee's corrective actions to restore the Unit 1 EDGs to service. Inspector activities during the shutdown were documented in NRC Inspection Report 05000282/2012004; 05000306/2012004. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

An inspector identified finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," is discussed in Section 4OA3.1 of this inspection report.

4OA5 Other Activities

.1 (Closed) Temporary Instruction-2515/182 - Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks

a. Inspection Scope

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued guidance document NEI 09-14, "Guideline for the Management of Buried Piping Integrity" (ADAMS Accession No. ML1030901420), to describe the goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. On December 31, 2010, NEI issued Revision 1 to NEI 09-14 (ADAMS Accession No. ML110700122), with an expanded scope of components which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued Temporary Instruction (TI)-2515/182, "Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks," to gather information related to the industry's implementation of this initiative.

From February 25 through March 1, 2013, the inspectors conducted a review of records and procedures related to the licensee's program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI-2515/182. This review was done to confirm that

the licensee's program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14 and to confirm that these attributes were scheduled and/or completed by the NEI 09-14, Revision 1, deadlines. To determine if the program attribute was accomplished in a manner which reflected good or poor practices in program management, the inspectors interviewed licensee staff responsible for the buried piping program. Additionally, the inspector performed a walkdown of rectifiers, anode beds and test points used for the operation and maintenance of the cathodic protection system.

Based upon the scope of the review described above, Phase II of TI-2515/182 was completed.

b. Observations

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.a of the TI and it was confirmed that activities which correspond to completion dates specified in the program which have passed since the Phase 1 inspection was conducted, have been completed.

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.b of the TI and responses to specific questions found in http://portal.nrc.gov/edo/nrr/dirs/irib/Inspection 20Manual 20Forms%20Templates%20Attachments/Forms/AllItems.aspx were submitted to the NRC Headquarters staff.

c. Findings

No findings were identified.

.1 Operation of an Independent Spent Fuel Storage Facility Installation at Operating Plants (60855.1)

Operation of an Independent Spent Fuel Storage

a. Inspection Scope

The inspectors observed and evaluated select licensee loading, processing, and heavy loads operations involving cask number 30. The inspectors verified compliance with the independent spent fuel storage (ISFSI) license conditions, ISFSI TS, and associated ISFSI procedures. Specifically, the inspectors observed: preparations for fuel loading; cask lid placement; removal of the cask from the spent fuel pool; removal of water from the cask; cask vacuum drying; and cask helium backfilling.

The inspectors reviewed procedures used to perform ISFSI cask receipt inspection, preparation, loading, processing, transfer, monitoring, and storage activities. The inspectors reviewed the licensee's procedures for compliance with its control of heavy loads program and associated crane standards.

The inspectors attended licensee infrequently performed evolution briefings, daily briefings, operations briefings, and in-field briefings to ensure the licensee was adequately preparing for in field operations and communicating the status of cask loading to appropriate individuals.

The inspectors reviewed the licensee's procedures associated with fuel characterization and selection for storage. Cask 30 is the first TN-40HT cask to be loaded with high burnup fuel at Prairie Island. The inspectors reviewed the fuel selection package for cask 30 to verify that the licensee was loading fuel in accordance with the TS approved contents. Parameters reviewed included fuel assembly heat load, type, initial enrichment, burnup, cooling time, and verification of no damage. The licensee did not load burnable poison rod assemblies or thimble plug devices.

The inspectors reviewed CAP documentation and the associated corrective actions. The inspectors reviewed the licensee's 10 CFR 72.48 screenings and evaluations since the last ISFSI inspection.

At the time of the inspection the licensee was undergoing license renewal for the Part 72 site specific ISFSI. Aspects of license renewal, including the licensee's proposed aging management plan were not inspected during this inspection; however, the aging management plan will be the subject of a future inspection.

Additional activities not reviewed during this inspection requiring review by inspection procedure IP 60855.1 were reviewed previously and documented in NRC Inspection Report 05000282/2012005, 05000306/2012005 and 07200010/2012001.

.2 (Closed) Unresolved Item 07200010/2012001-01: Addition of Gauge Inaccuracy to Procedural Acceptance Criteria May Cause Independent Spent Fuel Storage Installation Technical Specification Non-Compliance

a. Inspection Scope

On November 17, 2010, the licensee wrote CAP 1259086 due to the fact that acceptance criteria in the D95.3 procedures had not accounted for gauge inaccuracy when demonstrating compliance with the ISFSI TS. The inspectors reviewed CAP 1370456 and concluded that ISFSI TS for cask vacuum drying and helium backfilling may not have been met. The inspectors reviewed additional information pertaining to the licensee's operability determination. The licensee performed an operability assessment that concluded the casks would continue to perform their design function with the addition of the gauge inaccuracy. The inspectors reviewed the licensee's reportability evaluation that was performed to ensure the requirements of 10 CFR 72.75 were met. The inspectors reviewed the licensee's revised procedures to ensure adequate corrective actions were implemented.

This item did not constitute an inspection sample and is closed.

b. Findings

The inspectors consulted with the office of Nuclear Material Safety and Safeguards regarding compliance with the TS limits and operability analysis. A licensee identified NCV is documented in Section 4OA7 of this inspection report.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 11, 2013, the inspectors presented the inspection results to Mr. J. Lynch, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (TI -2515/182) with the Assistant Plant Manager, Mr. Tim Allen, and other members of the licensee staff on March 1, 2013.
- The inspection results for the area of radioactive solid waste processing and radioactive material handling, storage, and transportation with Mr. Kevin Davison, Director - Site Operations, on March 1, 2013.
- The operation of an ISFSI inspection with Mr. Kevin Davison, Director – Site Operations on March 28, 2013.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) or Severity Level IV were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy for being dispositioned as NCVs.

- Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, activities affecting quality shall be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures or drawings. Step 7.2.4 of SP 2324, “22 Battery Monthly Inspection,” required that the electrolyte level in each battery cell be observed and recorded on Table 2, “Battery Data Sheet.” Contrary to the above, on December 18, 2012, the system engineer identified that electrical maintenance personnel failed to accomplish SP 2324, “22 Battery Monthly Inspection,” an activity affecting quality, in accordance with the procedural instructions. Specifically, the electrolyte level of each cell was not recorded on Table 2. The failure to record the electrolyte level resulted in the licensee invoking TS Surveillance Requirement 3.0.3 due to the missed surveillance test. The licensee subsequently observed the electrolyte level in each cell of the 22 Battery and found that the levels were acceptable. The inspectors determined that the failure to follow SP 2324 was a performance deficiency. The inspectors assessed the significance of this deficiency using IMC 0609, Appendix A, “The Significance Determination Process for Findings at Power.” The inspectors determined that

this issue was of very low safety significance (Green) because each of the questions contained in the Mitigating Systems portion of IMC 0609, Appendix A, Exhibit 2 could be answered "no." The licensee documented this issue in CAP 1365129. Corrective actions for this issue included obtaining and recording the electrolyte levels, coaching personnel on the human performance tools that can be used to ensure procedure compliance, and providing additional training to maintenance supervision regarding their oversight responsibilities.

- Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR Part 50.2 and as specified in the license application, for those SSCs to which this appendix applies are correctly translated into specifications, drawings, procedures and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled. The design control measures shall provide for verifying or checking the adequacy of design such as by the performance of a suitable testing program. Contrary to the above, on January 5, 2013, the licensee identified that regulatory requirements regarding the testing of multiple ASME OM Code, Category A pressure isolation valves had not been correctly translated into procedures. As a result, the verification of each valve's design had not been adequately verified or checked by the performance of a suitable testing program since approximately February 25, 1998. The inspectors determined that the failure to perform suitable testing on multiple ASME OM Code, Category A pressure isolation valves was a performance deficiency. The inspectors assessed the significance of this deficiency using IMC 0609, Appendix A, "The Significance Determination Process for Findings at Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions contained in the Mitigating Systems portion of IMC 0609, Appendix A, Exhibit 2 could be answered "no." The licensee documented this issue in CAP 1365473. Corrective actions for this issue included satisfactorily performing testing on those valves that could be tested with the reactor at power, ensuring that valves that could only be tested during an outage were incorporated into the respective refueling outage schedule, and performing an extent of condition review to ensure that other valves were appropriately classified and tested as required by the ASME OM Code.

- Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures or drawings. Step 6.3 of Procedure SWI O-200.3, "Technical Specification Entry and Exit," required that a peer check be obtained when log entries regarding TS limiting conditions for operation (LCO) were made by another senior reactor operator (SRO). Contrary to the above, on January 10, 2013, the work control center SRO failed to obtain a peer check of a log entry made regarding the entry into TS LCO 3.7.8. As a result, the operations crew failed to identify that TS LCO 3.8.1 also needed to be entered. Because TS 3.8.1 was not entered, operations personnel failed to perform TS Surveillance

Requirement 3.8.1.1 within 1 hour of rendering the D1 EDG inoperable. This issue was identified by an oncoming SRO as part of his shift turnover activities. The inspectors determined that the failure to follow SWI O-200.3 was a performance deficiency. The inspectors assessed the significance of this deficiency using IMC 0609, Appendix A, "The Significance Determination Process for Findings at Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions contained in the Mitigating Systems portion of IMC 0609, Appendix A, Exhibit 2 could be answered "no." The licensee documented this issue in CAP 1366155. Corrective actions for this issue included successfully satisfying the requirements of TS Surveillance Requirement 3.8.1.1, discussing the event with all operations personnel, issuing an operating instruction to provide additional guidance regarding entry into and exiting of LCOs, and removing the involved SROs from licensed duties until remedial training could be provided.

- Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, activities affecting quality shall be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures or drawings. Contrary to the above, on February 5, 2013, maintenance personnel calibrated a differential pressure switch on the 11 shield building ventilation system, an activity affecting quality, without having instructions, procedures, or drawings appropriate to the circumstance. The failure to have instructions or procedures appropriate to the circumstance resulted in maintenance personnel unknowingly rendering the 11 shield building ventilation system inoperable. In addition, the inappropriate work instructions and a lack of communications from the maintenance personnel to the licensed operators resulted in a failure to implement TS 3.6.9 once the 11 shield building ventilation system became inoperable. The inspectors assessed the significance of this finding using IMC 0609, Appendix A, "The Significance Determination Process for Findings at Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions contained in the Mitigating Systems portion of IMC 0609, Appendix A, Exhibit 2 could be answered "no." The licensee documented this issue as CAP 1369077. Corrective actions for this issue included performing a site wide stand down to reinforce the requirement that work on safety related equipment must be documented by instructions or procedures appropriate for the task at hand, removing the maintenance workers qualifications until remedial training could be provided, and placing an additional supervisor within the specific maintenance department to ensure that individuals fully understood the scope of the work requested to be performed.

- Title 10 CFR Part 72.150, "Instructions, Procedures and Drawings," requires, in part, that licensees shall prescribe activities affecting quality by documented instructions, procedures, or drawings of a type appropriate to the circumstances. Instructions, procedures, and drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, prior to November 17, 2010, the licensee failed to perform ISFSI surveillance requirement testing with a

procedure appropriate to the circumstance. Specifically, quantitative acceptance criteria contained in D95.3, “TN-40 Cask Removal and Storage Procedure, Revision 15,” and preceding revisions did not include gauge uncertainty when performing cask vacuum drying and helium backfilling surveillance requirements. As a result, the licensee was unable to verify that casks 1-26 were loaded in accordance with cask technical specification requirements.

The violation was determined to be more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” and Appendix E, Example 4c. Consistent with the guidance in the NRC Enforcement Manual, Section 2.6.D, if a violation does not fit an example in the enforcement policy violation examples, it should be assigned a severity level: (1) commensurate with its safety significance; and, (2) informed by similar violations addressed in the Violation Examples. The violation screened as having very low safety significance, Severity Level IV. Specifically, following identification of the issue the licensee performed an operability assessment that showed the casks would continue to perform their design function with the addition of the gauge inaccuracy. The licensee documented this issue as CAPs 1259086 and 1370456. Corrective actions for this issue included issuing the revised procedure, performing an extent of condition review, performing an operability assessment of affected casks, and screening the issue for reportability.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Lynch, Site Vice President
K. Davison, Director – Site Operations
A. Mitchell, Site Engineering Director
S. Sharp, Plant Manager
T. Allen, Assistant Plant Manager
J. Anderson, Regulatory Affairs Manager
J. Boesch, Maintenance Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
K. DenHerder, Backup Buried Pipe Program Owner
D. Gauger, Chemistry/Environmental Manager
J. Hamilton, Security Manager
J. Lash, Nuclear Oversight Manager
S. Lappegaard, Production Planning Manager
B. Meek, Safety and Human Performance Manager
O. Nelson, ISFSI Project Engineer
K. Peterson, Business Support Manager
J. Ruttar, Operations Manager
L. Samson, Corporate Manager Spent Fuel Projects
P. Taylor, Buried Pipe Program Owner

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2
T. Wengert, Project Mananger, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000306/2013002-01	NCV	Failure to Properly Secure Materials Near Critical Drainage Path (Section 1R06)
05000282/2013002-02	NCV	Failure to Correct Condition Adverse to Quality for Valve SI-6-4 (Section 1R22.1b.(1))
05000306/2013002-03	NCV	Failure to Follow Procedure During Fuse Removal Activities (Section 1R22.1b.(2))
05000282/2013002-04	NCV	Inadequate Work Instructions for Foreign Material Removal From D2 EDG Air Start Piping (Section 1R22.1b.(3))
05000306/2013002-05	NCV	Improperly Sized Motor Overload Heaters Render D6 EDG Inoperable (Section 1R22.1b(4))
05000306/2013002-06	FIN	Failure to Provide Accurate Performance Indicator Data (Section 4OA1.5)
05000306/2013002-07	NCV	Failure to Provide Accurate Performance Indicator Data (Section 4OA1.5)
05000282/2013002-08	NCV	Failure to Correct Condition Adverse to Quality on the D1 EDG (Section 4OA3.1)

Closed

05000306/2013002-01	NCV	Failure to Properly Secure Materials Near Critical Drainage Path
05000282/2013002-02	NCV	Failure to Correct Condition Adverse to Quality for Valve SI-6-4
05000306/2013002-03	NCV	Failure to Follow Procedure During Fuse Removal Activities
05000282/2013002-04	NCV	Inadequate Work Instructions for Foreign Material Removal From D2 EDG Air Start Piping
05000306/2013002-05	NCV	Improperly Sized Motor Overload Heaters Rendered D6 EDG Inoperable
05000306/2013002-06	FIN	Failure to Provide Accurate Performance Indicator Data
05000306/2013002-07	NCV	Failure to Provide Accurate Performance Indicator Data
05000282/2013002-08	NCV	Failure to Correct Condition Adverse to Quality on the D1 EDG
05000282/2012004-02	URI	Unit 1 Required Shutdown due to D1 and D2 EDG Exhaust Fires
05000282/2012-005-00	LER	Unit 1 Diesel Generators Inoperable due to Exhaust Fire
2515/182	TI	Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks
07200010/2012001-01	URI	Addition of Gauge Inaccuracy to Procedural Acceptance Criteria May Cause ISFSI Technical Specification Non-Compliance

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment

- C1.1.20.7-13; D6 Diesel Generator Valve Status; Revision 15
- C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels And Switches; Revision 12
- C1.1.20.7-15; D6 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 6
- C1.1.20.7-16; D6 Diesel Generator Circuit Breakers and Panel Switches; Revision 8
- C1.1.35-1; Cooling Water System Unit 1; Revision 11
- C1.1.35-2; Cooling Water System Unit 2; Revision 10
- C1.1.35-3; Cooling Water System; Revision 31
- C37.11-1; Chilled Water Safeguards System; Revision 20
- CAP 1267344; 12 Diesel Driven Cooling Water Pump Line Shaft Bearing Flow Switch Low Flow; January 21, 2011
- CAP 1268625; Cooling Water System Summer Readiness Review; January 31, 2011
- CAP 1269706; Cooling Water System Walkdown Deficiencies in Turbine Building; February 4, 2011
- CAP 1271753; CV-31381 11 Component Cooling Heat Exchanger Cooling Water Outlet Control Valve Outside Reference Range; February 19, 2011
- CAP 1305309; 12 Diesel Driven Cooling Water Pump Shutdown Solenoid not Reset; October 15, 2011
- CAP 1369572; 2FO-4-14 D5/D6 Fuel Oil Storage Tansk Emergency Fill Connection Not At Full Closed; February 8, 2013
- System Health Report; Cooling Water System; no date provided

1R05 Fire Protection

- CAP 1368986; NRC Inspector Questioned Wood Stool in Auxiliary Feedwater Pump Room Cage; February 4, 2012
- Procedure F5 Appendix A; Fire Zone Plans and Maps; Various Revisions
- Procedure F5 Appendix F; Fire Hazard Analysis; Revision 27

1R06 Flood Protection (Internal)

- 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 9
- CAP 1178236; No HELB Flooding Calculation For Turbine Building; April 15, 2009
- CAP 1368845; Barrels Improperly Tethered 695' U2 Turbine Truck aisle; February 4, 2013
- CAP 1374550; Barrels Improperly Tethered in Critical Drainage Area; March 14, 2013
- OPR 1178236; No HELB Flooding Calculation For Turbine Building; October 9, 2009

1R12 Maintenance Effectiveness

- B8; AMSAC/DSS System Description; Revision 8

- ECE 1335166-04; Trip of 22 Reactor Coolant Pump not Recognized by AMSAC; November 1, 2012
- Figure B8-6; AMSAC/DSS Actuation Logic; Revision 8
- Figure B8-8; AMSAC/DSS Logic; Revision 8

1R13 Maintenance Risk Assessment and Emergent Work

- CAP 1369880; Hot Work Caused Fire Alarm in Fire Protection Zone 2 – F5 Appendix K Protected; February 12, 2013
- CAP 1370259; Missed Opportunity for CT 11 Risk during EDG 1 and 2 Maintenance; February 13, 2013
- FP-OP-COO-01, Attachment 19; Work Management; Revision 9
- FP-OP-COO-01, Attachment 6; Control Room Conduct; Revision 11
- FP-OP-PEQ-01; Protected Equipment Program; Revision 9
- Weekly and Daily Work Management Risk Assessment Reports

1R15 Operability Evaluations

- CAP 1238829; RCS Leak Detection WRT R11 In Question; June 24, 2010
- CAP 1355122; Found Pipe Hanger RSIH-22 Disconnected in Unit 1 Containment; October 15, 2012
- CAP 1362575; Seismic Alarms Caused by Voltage Sags; December 10, 2012
- CAP 1364224; 21/22 Condensate Storage Rank Temperature Exceeded 92 Degrees; December 21, 2012
- CAP 1366645; Received Valid Event Alarm on Seismic Monitoring Panel; January 16, 2013
- CAP 1367286; G1 Does Not Credit A Specific Procedure For SR 3.4.16.2; January 21, 2013
- Control Room Narrative Logs; December 21, 2012
- EC 21354; Determine Maximum Operating Temperature of Condensate Storage Tank; Revision 0
- Emergency Action Level Reference Manual; Revision 5
- Maintenance Rule Functional Failure Evaluation 1364224; Unit 2 Condensate Storage Tanks Exceeded 92 Degrees; January 2, 2013
- OPR 1238829; RCS Leak Detection WRT R11 In Question; Revision 1
- OPR 1367286; G1 Does Not Credit A Specific Procedure For SR 3.4.16.2; January 29, 2013

1R19 Post Maintenance Testing

- 5AWI 3.12.4; Post-Maintenance Testing; Revision 22
- CAP 1367373; Bus 26 Safeguards Load Sequencer Failure In SP 2095; January 22, 2013
- CAP 1369251; Question Encountered On Operability of 22 Shield Building Vent; February 6, 2013
- FP-WM-OVW-01; Work Management Overview; Revision 9
- ICPM 0-035-22; 22 Shield Building Exhaust PAC Filter Temp Switch Cal; Revision 7
- PE-0007; 5HK250/350 Breaker Testing Maintenance & Repair – Minor; Revision 10
- PM 3002-2-22; 22 DDCLP Diesel Minor Periodic Maintenance; Revision 40
- SP 2073B; Monthly Train B Shield Building Ventilation System Test; Revision 8
- SP 2095; Bus 26 Load Sequencer Test; Revision 30
- SWI 0-200.3; Technical Specification Entry And Exit; Revision 0
- USAR Section 5; Prairie Island Updated Safety Analysis Report; Revision 31
- WO 449508; PE-26-13 Breaker Testing, Maintenance, & Repair (Breaker 26-13); January 30, 2013

- WO 455753; PM 3002-2-22; 22 DDCLP Diesel Minor Periodic Maintenance; February 27, 2013
- WO 472791; Bus 26 Load Sequencer Failure In SP 2095; January 23, 2013
- WO 473283; Perform Post Maintenance Testing on CV-31954 and Solenoid Valve 33644; February 4, 2013
- Work Plan 433400-03; Mech:SV-33751, Remove Socket Welds; Revision 00
- Work Plan 433400-08; Perform Post Maintenance Test For SV-33751; Revision 00
- Work Plan 472791-01; Bus 26 Load Sequencer Failure In SP 2095; January 22, 2013

1R22 Surveillance Test

- ASME OMa Code-1999; ISTC-5224 – Corrective Action; no date provided
- ASME OMb Code-2000; ISTC-3630 - Leakage Rate for Other Than Containment Isolation Valves; no date provided
- CAP 1356631; Foreign Material Found in D2 Replacement Air Start Assembly; October 26, 2012
- CAP 1365445; Site Application of ISTC 5223 for SI-6-4 Testing; January 4, 2013
- CAP 1365705; Generic Letter 87-06 Response on Category A Valve Seat Leakage; January 8, 2013
- CAP 1368044; D2 Failed to Start and Locked Out During SP 1305; January 28, 2013
- CAP 1371080; Load on D6 Radiator Fan Appears Higher than Anticipated; February 20, 2013
- CAP 1377245; D5/D6 Radiator Fan MOLR Sizing; April 2, 2013
- CAP 46556; Breaker 211K-7 for Radiator Fan Tripped; April 11, 1995
- CAP 567296; D5 Engine 2 Fan 2 Breaker Tripped on Thermal Overload; January 19, 2004
- Certificate of Conformance Xcel Energy Purchase Order 00036957, Revision 001; October 25, 2012
- ECE 1363570; D6 Engine 1 Fan #2 Stopped during SP 2305; February 14, 2013
- FP-SC-RSI-02; Quality Receipt; Revision 11
- FP-SC-RSI-03; Overage, Shortage, Damaged and Discrepant Report; Revision 8
- H6.3; General Electric Thermal Overload Heater Sizing for Non-Motor Operated Valve Motors; Revision 4
- OSD&D Report 4792; October 30, 2012
- PMCR 1042070; Update D5 and D6 Breaker Preventive Maintenance; July 31, 2006
- Quality Inspection Checklist for Purchase Order 36957; D1/D2 Air Start Assembly; October 29, 2012
- SP 1094; Bus 15 Load Sequencer Test; Revision 30
- SP 1305; D2 Diesel Generator Monthly Slow Start Test; Revision 47
- SP 2095; Bus 26 Load Sequencer Test; Revision 30
- SP 2285 – Containment Isolation Valves For RCDT to Gas Analyzer Quarterly; Revision 16
- WO 0471243; SP 2285 Containment Isolation Valves For RCDT to Gas Analyzer Quarterly; March 19, 2013
- WO 422107-01; Replace D2 Diesel Generator Air Start Valves; October 29, 2012
- WO 422107-10 #1; D2 Air Start Using CV-31956; Revision 0
- WO 422107-10 #2; D2 Air Start Using CV-31955; Revision 0
- WO 449743-01; SP 1094 Bus 15 Load Sequencer Monthly Test; January 14, 2013
- WO 450208-01; SP 2095 Bus 26 Load sequencer Monthly Test; January 22, 2012
- WO 452600-1; D2 Diesel Generator Local Manual Air Start with Voltage Regulator Calibration and Speed Droop Adjustment; Revision 0

1EP6 Emergency Preparedness

- EP Drill Narrative Summary; February 12, 2013
- SEG P9112SD-0601; Simulator Exercise Guide Licensed Operator Requalification Cycle 12F

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation

- C49.10; Clamshell Operations; Revision 16
- CAP 1318422; Snapshot Self-Assessment; Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation; dated January 18, 2013
- CAP 1336648; ODCM Change Documentation Not In Accordance With Technical Specification Requirements; dated May 7, 2012
- CAP 1337791; Radioactive Waste Shipping Vehicle Inspection Weakness; dated May 15, 2012
- CAP 1353146; FF21 Shipment Delayed Due to Unqualified Personnel; dated October 12, 2012
- CAP 1361792; Obscured High Radiation Area Posting at the 12 RHR Pit Entrance; dated December 4, 2012
- CAP 1369448; Stop Work Initiated for Radioactive Material Shipments; Monticello NRC Shipping Inspection OE; dated February 7, 2013
- D11.11; Radioactive Material Shipment LSA/SCO/LDT Quantity to a Licensed Processing Facility; Revision 17
- D11.7; Radioactive Material Shipment LSA/SCO/LDT Quantity to a Licensed Facility; Revision 21
- D20.13; Sluicing Resin from 12 Mixed Bed IX to 121 Spent Resin Tank; Revision 19
- D20.16; Sluicing Resin from 11 Evap Condensate IX to a Resin Shipping Liner; Revision 16
- D59; Process Control Program for Solidification/Dewatering of Radioactive Waste from Liquid Systems; Revision 10
- FP-RP-RW-02; Radioactive Shipping Procedure; Revision 6
- FP-WM-IRM-01; Integrated Risk-Management; Revision 8
- NOS Observation Report 2012-02-003; Radiation Protection; May 15, 2012
- NOS Observation Report 2012-03-025; Radiation Protection; September 21, 2012
- NOS Observation Report 2012-04-031; Radiation Protection; December 31, 2012
- PM 4629; WL and WG Concealed Tank Inspections; Revision 1
- QF-2007; (FP-WM-IRM-01); Planning and Approval of High Risk or Scheduled Risk Work; Revision 3
- QF-2010; (FP-WM-IRM-01); Work Order Risk Screening Worksheet; Revision 15
- RPIP 1303; Packaging of Radioactive Material for Shipment; Revision 9
- RPIP 1310; Rad Waste Streams Scaling Factors; Revision 11
- RPIP 1319; Loading LSA Boxes/Sealand Containers; Revision 20
- RPIP 1721; Resin Sluice; Revision 22
- Shipment Number 11-005; Class B Resin HIC 139; March 2011
- Shipment Number 11-012; Damaged Fuel Assembly; April 2011
- Shipment Number 11-052; Westinghouse Sipper; December 2011
- Shipment Number 12-037; One (1) New Fuel Bundle; September 2012
- Shipment Number 12-049; DAW Sealands; December 2012
- Title 10 CFR Part 61 Waste Characterization Analysis; Bead Resin; August 2012
- Title 10 CFR Part 61 Waste Characterization Analysis; Dry Active Waste; August 2012
- Title 10 CFR Part 61 Waste Characterization Analysis; High Level Filters; August 2012

- Title 10 CFR Part 61 Waste Characterization Analysis; Low Level Filters; August 2012
- Title 10 CFR Part 61 Waste Characterization Analysis; SGBD Resin; February 2013

4OA1 Performance Indicator Verification

- CAP 1367890; MSPI EAC Unreliability Index Data Incomplete for 3Q12 and 4Q12; January 24, 2013
- CAP 1369056; Emergency AC Power MSPI Indicator is White; February 5, 2013
- CAP 1369064; NRC Performance Indicator Data Submitted without MSPI Failure Data; February 4, 2013
- FG-E-ICES-01; ICES Equipment Failure Reporting; Revision 0
- FP-PA-PI-02; NRC/INPO/WANO Performance Indicator Reporting; Revision 6
- H33.2; Mitigating Systems Cornerstone Unavailability Performance Indicator Reporting Instructions; Revision 9
- H33; Performance Indicator Reporting; Revision 12
- MSPI Failure Determination 1363570-03; D6 Engine 1 Fan 2 Stopped during SP 2305; January 14, 2013

4OA2 Identification and Resolution of Problems

- ACE 1233577-01; Apparent Cause Evaluation for CAP 1233577; August 5, 2010
- CAP 1233577; Unit 2 RHR Suction Check Valves Fail SP 2369 Closed Function; May 19, 2010
- CAP 1326085; 2RH-3-2 21 RHR Pump Suction Check Failed; February 22, 2012
- CAP 1332102; Adverse Trend Noted in Operator Fundamentals; April 3, 2012
- CAP 1371053; Adverse Trend in Drill and Exercise Performance Failures from January 2012 through February 2013; February 19, 2013
- EC 19885; Past Operability for 2RH-3-2; April 6, 2012

4OA5 Other Activities

- 10 CFR 72.75 Review – Cap 01259086; D95.3 Revision 16 Does Not Account for Meter
- 2013CA001; UT Thickness Calibration Report, LIS 18008 and LIS 18009; January 29, 2013
- 72.48-1099; Shorter Aluminum and Poison Plates in TN-40HT Casks; Revision 0
  Accuracy
  Amendment Nos. 92 and 93
- Annual Cathodic Protection Survey PINGP; August 15, 2012
- BOP-UT-12-034; UT Thickness Examination, 3-FO-44 for Buried Pipe Program; August 8, 2012
- BOP-VT-12-115; VT-3 Report for 30” CW, 30”-CL-123, ID of 30” Pipe and Elbow; November 23, 2012
- BOP-VT-13-004; VT-1 Report for LIS 18008 and LIS 18009 ½” SA Piping; January 29, 2013
- CAP 1197637; Failed QC Coatings Inspection; December 18, 2009
  CAP 1249377; Plant Operators have Logged ISFSI Pressure as Unable to Scan; September 12, 2010
  CAP 1259086; D95.3 Revision 16 Does Not Account for Meter Accuracy; November 17, 2010
- CAP 1342828; Deferral of PMID 6614-09 CW System Structure Inspection; June 25, 2012
  CAP 1366377; No Auxiliary Building Crane Minimum Operating Temperature Specified; January 13, 2013
- CAP 1370456; Original ISFSI TS 2.1 and TS 2.2 Not Met; February 15, 2013
- CAP 1370752; Snap Shot NEI 09-14 Revision 1, H58, H%*.1, and CD 5.39; February 18, 2013

- CAP 1371183; U2 FOST Vaults not Included in NEI 09-014 R1 Scope; February 21, 2013
- CAP 1371191; UPTI SSA: BPWORKS Risk Rank for DE/WL Piping May be Too High; February 21, 2013
- CAP 1371280; UPTI SSA: Add New Environmentally Sensitive Scope per NSIAC; February 21, 2013
- CAP 1371296; UPTI SSA: Undocumented Prioritization of Underground Pipes; February 21, 2013
- CAP 1371297; 4 percent of APEC Survey Areas not Covered by CP; February 21, 2013
- CAP 1376685; Cask 30 Has Boric Acid Buildup on Vent Port; March 28, 2013
- CAP 1376790; Cask 30 Helium Leak Rate TS Surveillance Not Met; March 29, 2013
- CAP1267747; NEI 09-14 Guidelines for the Management of Buried Piping Evaluate NEI 09-14 [Rev 1]; January 25, 2011
- CD 5.26; Program Engineering; Revision 5
- CD 5.39; Fleet Underground Piping and Tank Integrity Program Standard; Revision 2
- D92; Excavation; Revision 9
- D95.1; TN-40 Cask Loading Procedure; Revision 19
  D95.3; TN-40 Cask Removal and Storage Procedure; Revision 21
- D95.4; TN-40 Cask Receipt Procedure; Revision 23
- D95.7; Auxiliary Building Crane Malfunction with and Empty Cask; Revision 0
- D95.8; Auxiliary Building Crane Malfunction with a Loaded Cask; Revision 0
- D95.9; Establishment of Helium Environment; Revision 0
- Evaluation of TS Compliance CE01259086-06
- FL-ESP-PGM-063M; Underground Piping and Tank Integrity (UPTI) Program Owner; Revision 3
- FP-PE-NDE-425; Ultrasonic Thickness Examination – Localized Corrosion; Revision 1
- FP-PE-PHS-01; Program Health Process; Revision 14
- Generic Licensing Topical Report EDR-1 (P)-A; October, 8, 1982
- H 58.1; PINGP Buried Pipe Inspection Plan; Revision 0
- H 58; Underground Piping and Tank Integrity Program; Revision 3
- H24.3; Structures Monitoring Program; Revision 9
  January 22, 2013
- Letter from TN to Prairie Island; Expanded Operability Discussion for Casks 1 through 26;
- Letter to PINGP; SER, PINGP, Units 1 and 2 – Relief Request from ASME Code, Section XI, Inservice Inspection Program Relief Requests Nos. 1-RR-4-7 and 2-RR-4-7 (TAC Nos. MD3809 and MD3810); October 31, 2007
- Letter to R. William Borchardt; Revision to the Industry Initiative on Underground Piping and Tanks Integrity; February 8, 2013
- MIC-09-069, 70, 71, 72; UT Thickness Examination of FP Piping, NF-39256-1 P1; September 11, 2009
- MWO 105237; Unit 0 Ground and Cathodic Protection System; Revision 2
- PING 196; Turbine Building Data – Unit 2; Revision 111
- PING 196; Turbine Building Data – Unit 2; Revision 112
- PINGP 1066; CL/FP Pipe or CL HX Internal Inspection; Revision 10
- PM 3586-10; Periodic Structures Inspection; Revision 8
- QF-1030-17; Corrosion of Plant Materials; Revision 0
- QF-1030-20; Fleet Mentor Guide, Engineering Support Personnel Training Program, FL-ESP-TPD; Revision 6
- QF-1306; Excavation Permit; Revision 8
- Quarterly Program Health Report Buried Pipe and Tank Program PINGP; February 11, 2013

- Report No. 1101501.402; Area Potential and Earth Current (APEC) Survey, PINGP; Revision 0
- Safety Evaluation Report – Prairie Island Nuclear Generating Plant, Units Nos. 1 and 2;
- SP 1075.HT; TN-40HT Fuel Selection and Identification; Revision 2
- Spec 106A – Sect. II; Standard Specification Protective Coating for Steel Pipe; January 1, 1976
- TP 1626; Cathodic Protection Monthly Inspection; Revision 12
- WO 379943; Eng-Inspect Buried Portions of 6-FP-22 and 10-FP-22; November 12, 2009
- WO 408202; PM 3586 Circ Water System Structure Inspection; November 23, 2012
- WO 419861; U0 Inspect 3" Buried Fuel Oil Pipe East of PT Screenhouse; August 6, 2012
- WO 419862; U1 Inspect 30" CL & 2" SA Line Between PT Screenhouse and Turbine Building; November 16, 2012
- WO 427745; Cathodic Protection Monthly Inspection; January 16, 2012
- WO 427747; Cathodic Protection Monthly Inspection; March 5, 2012
- WO 432265; Cathodic Protection Monthly Inspection; June 4, 2012
- WO 438332-01; SP 1075 TN-40 Fuel Selection and Identification; March 20, 2013
- WO 448984; Cathodic Protection Monthly Inspection; January 7, 2013

4OA7 Licensee Identified Non-Cited Violations

- ASME OMa Code-1999; ISTC-5224 – Corrective Action; no date provided
- ASME OMb Code-2000; ISTC-3630 - Leakage Rate for Other Than Containment Isolation Valves; no date provided
- CAP 1365129; Acceptance Criteria for 22 Battery SP 2324 Missed for 58 Cells; January 2, 2013
- CAP 1365445; Site Application of ISTC 5223 for SI-6-4 Testing; January 4, 2013
- CAP 1365705; Generic Letter 87-06 Response on Category A Valve Seat Leakage; January 8, 2013
- CAP 1365876; Missed Technical Specification Surveillance and Untimely Surveillance Requirement 3.0.3 Entry; January 9, 2013
- CAP 1366155; Unit 1 Shift Supervisor Failed to Enter LCO 3.8.1 Upon Entering LCO 3.7.8; January 10, 2013
- CAP 1369077; Fix it Now Team Inadvertently Rendered 11 Shield Building Ventilation System Inoperable; February 5, 2013
- Clearance Order 44510; ICPM 0-035-21 – 21 Shield Building Ventilation Exhaust Filter Technical Specification Calibration; February 13, 2012
- Control Room Narrative Logs; February 13, 2012
- G1; Surveillance and Periodic Test Program; Revision 47
- H37; Battery Monitoring and Maintenance Program; Revision 4
- ICPM 0-035-21; 21 Shield Building Exhaust PAC Filter Temperature Switch Calibration; Revision 7
- SP 2324; 22 Battery Monthly Inspection; Revision 15
- WO 447899-01; SP 2324 22 Battery Monthly Inspection; December 18, 2012

LIST OF ACRONYMS USED

ΔCDF	Change in Core Damage Frequency
AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agencywide Document Access Management System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CV	Control Valve
DRP	Division of Reactor Projects
ECE	Equipment Causal Evaluation
EDG	Emergency Diesel Generator
gpm	Gallons per Minute
IMC	Inspection Manual Chapter
IN	Information Notice
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
IST	In-Service Testing
LCO	Limiting Condition for Operation
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MOLR	Motor Overload Relay
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OM	Operations and Maintenance
OOS	Out of Service
OPR	Operability Recommendation
OSD&D	Overage, Shortage, Damage and Discrepancy
PARS	Publicly Available Records System
PCP	Process Control Program
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Post Maintenance
psig	Pounds Per Square Inch Gauge
RASP	Risk Assessment Standardization Project
RER	Radiological Effluent Release
RHR	Residual Heat Removal
SDP	Significance Determination Process
SI	Safety Injection
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst

SRO	Senior Reactor Operator
SSC	Systems, Structures, and Components
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
USGS	United States Geological Survey
WO	Work Order

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Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

Docket Nos. 50-282; 50-306; 72-010
License Nos. DPR-42; DPR-60; SNM-2506

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Letter to J. Lynch from K. Riemer dated May 14, 2013

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2013002;
05000306/2013002; AND 07200010/2013001

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