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

November 5, 2012

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 05000282/2012004; 05000306/2012004

Dear Mr. Lynch:

On September 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on October 11, 2012, with Mr. Joel Sorensen 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.

One NRC-identified finding of very low safety significance (Green) was identified during this inspection. This finding was determined to involve a violation of NRC requirements. The NRC is treating this violation as a non-cited violation (NCV) in accordance with Section 2.3.2 of the NRC 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, 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 Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading rm/adams.html (the Public Electronic Reading Room).

Sincerely,

***/RA/***

Kenneth Riemer, Branch Chief
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 05000282/2012004; 05000306/2012004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Docket Nos.: | 50-282; 50-306; 72-010 |
| License Nos.: | DPR-42; DPR-60; SNM-2506 |
| Report No: | 05000282/2012004; 05000306/2012004 |
| Licensee: | Northern States Power Company, Minnesota |
| Facility: | Prairie Island Nuclear Generating Plant, Units 1 and 2 |
| Location: | Welch, MN |
| Dates: | July 1, 2012 through September 30, 2012 |
| Inspectors: | K. Stoedter, Senior Resident Inspector<br>P. Zurawski, Resident Inspector<br>T. Bilik, Reactor Inspector<br>B. Kemker, Senior Resident Inspector – Clinton<br>G. O'Dwyer, Reactor Inspector<br>A. Shaikh, Reactor Inspector |
| Approved by: | K. Riemer, Branch Chief<br>Branch 2<br>Division of Reactor Projects |

Enclosure

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## SUMMARY OF FINDINGS

IR 05000282/2012004; 05000306/2012004; 07/01/2012-09/30/2012; Prairie Island Nuclear Generating Plant, Units 1 and 2; Heat Sink.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. One Green finding was identified by the inspectors. The finding was considered a non-cited violation (NCV) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 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 associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to adequately verify the adequacy of the design of systems needed during a Design Basis Accident (DBA). Specifically, the licensee failed to verify that the degradation identified during as-found inspections on the 21 and 22 Component Cooling (CC) Water Heat Exchangers would not have prevented the heat exchangers (HXs) from performing their safety functions if a DBA had occurred. The licensee entered this issue into their corrective action program as CAPs 1348544 and 1349624. The licensee concluded by additional analysis, and engineering judgment, that the Heat Exchangers had remained operable. The licensee was also considering flushing the heat exchangers more frequently; inspecting and cleaning the HXs more frequently; modifying the CC heat exchangers to provide a more effective flush; and changing plant documents and/or programs to require opening, inspecting, and cleaning of the HXs following major dredging near the plant intake.

This issue was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control and impacted the objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The as-found condition of the HXs challenged the capability of the CC system to fulfill its safety function; however, the licensee did not fully evaluate the condition. The finding was of very low safety significance because the design deficiency did not result in a loss of operability or functionality. The inspectors determined the finding was cross-cutting in the Human Performance, Work Control, Work Practices area because the licensee did not properly ensure that supervisory and management oversight of work activities, including contractors, supported nuclear safety (H.4(c)). Specifically, licensee personnel reviewing and approving Engineering Changes (ECs) 20044 and 20222 did not require the preparer to provide adequate technical support as part of the past operability evaluation discussed in the ECs. (Section 1R07.1)

### B. Licensee-Identified Violations

No violations were identified.

# REPORT DETAILS

## Summary of Plant Status

The inspection period began with Unit 1 operating at full power. On August 14, 2012, operations personnel shut down the Unit 1 reactor to comply with Technical Specification (TS) requirements after discovering that both of the Unit 1 emergency diesel generators (EDGs) were inoperable due to a common cause. Operations personnel returned Unit 1 to power on August 21, 2012. Unit 1 operated at full power for the remainder of the inspection period.

Unit 2 operated at full power levels for the entire inspection period.

## 1. REACTOR SAFETY

**Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity**

1R01 Adverse Weather Protection (71111.01)

.1 Readiness For Impending Adverse Weather Condition – Extreme Heat/Drought Conditions

a. Inspection Scope

The inspectors continued to perform an inspection of the licensee's readiness for extreme heat conditions which began on June 26, 2012. The initial results of this inspection were documented in NRC Inspection Report 05000282/2012003; 05000306/2012003. As part of this inspection, the inspectors performed a detailed review of the licensee's procedures and preparations for operating the facility during an extended period of time when the ambient outside temperature was high, the ultimate heat sink (UHS) was experiencing elevated temperatures, and the licensee was monitoring multiple pieces of mitigating systems equipment due to temperature concerns. The inspectors focused on plant specific design features and implementation of the procedures for responding to or mitigating the effects of these conditions on the operation of the cooling water, auxiliary feedwater, EDG, and emergency core cooling systems. Inspection activities included a review of the licensee's adverse weather and summer readiness procedures, daily monitoring of the off-normal environmental conditions, and that operator actions specified by plant specific procedures were appropriate to ensure operability of the mitigating systems equipment discussed above. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01-05.

b. Findings

See Section 4OA5.2 for additional details regarding this inspection.

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:

- D2 EDG (D1 EDG Out of Service (OOS) Due to Exhaust Header Fire);
- 22 Diesel Driven Cooling Water Pump (21 Diesel Driven Cooling Water Pump OOS for Planned Maintenance); and
- D6 EDG with D5 EDG OOS for Voltage Control.

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), TS requirements, outstanding work orders (WOs), condition 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 operable. The inspectors examined the material condition of the components and observed operating parameters of equipment 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 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 availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Area – 13 (Control Room);
- Fire Area – 59 (Unit 1 Auxiliary Building Mezzanine Level);
- Fire Area – 73 (Unit 2 Auxiliary Building Ground Level);

- Fire Area – 117 (4kV Bus 25); and
- Fire area – 127 (480V Bus 211/212).

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 OOS, 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 (IPEEE) 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 five 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 July 20, 2012, licensee personnel identified that a concrete pipe trench cover located in the D5/D6 EDG building had been removed for planned maintenance with Unit 2 operating at 100 percent power. When installed, the trench cover protected the D5 and D6 EDGs from a high energy line break (HELB) induced internal flood. Operations personnel immediately declared the D5 and D6 EDGs inoperable as required by TS 3.8.1. The inspectors reviewed the USAR and the internal flooding and HELB procedures to determine the design, licensing and procedural requirements for the trench cover. The inspectors also reviewed maintenance planning procedures and activities to determine the sequence of events which led to the trench cover being removed with the Unit 2 reactor at power. Lastly, the inspectors ensured that the trench cover was re-installed within two hours of discovery which allowed operations personnel to return the EDGs to an operable status. 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

The licensee reported this issue to the NRC on September 14, 2012, via Licensee Event Report (LER) 05000306/2012-002-00, "Unit 2 Diesel Generators Inoperable due to Missing Hazard Barrier." The licensee's causal evaluation, including a review of whether previously identified manual actions would have been sufficient to protect the EDGs from a HELB induced flood, was ongoing at the conclusion of the inspection period. As a result, the inspectors were not able to determine whether a performance deficiency existed. The inspectors will review the results of the licensee's causal evaluation, and determine whether a performance deficiency occurred, as part of the closure of LER 05000306/2012-002-00.

1R07 Triennial Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillances, vendor manual information, associated calculations, performance test results and cooler inspection results associated with the 21 and 22 CC Water HXs. This heat exchanger/cooler was chosen based on its risk significance in the licensee's probabilistic safety analysis, its important safety-related mitigating system support functions, its operating history, and its relatively low margin.

The inspectors verified that testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs were adequate to ensure proper heat transfer. This was accomplished by verifying the test method used was consistent with accepted industry practices or equivalent; the test conditions were consistent with the selected methodology; the test acceptance criteria were consistent with the design basis values; and results of heat exchanger performance testing met the established acceptance criteria. The inspectors also verified that the test results appropriately considered differences between testing conditions and design conditions, the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values, and test results considered test instrument inaccuracies and differences.

The inspectors reviewed the methods and results of HX performance inspections. The inspectors verified the methods used to inspect and clean HXs were consistent with as-found conditions identified and expected degradation trends and industry standards, the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards, and the as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

In addition, the inspectors verified the condition and operation of the 21 and 22 CC Water HXs was consistent with design assumptions in heat transfer calculations and as described in the USAR. This included verification that the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. The inspectors verified the licensee evaluated the potential for water hammer and established adequate controls and operational limits to prevent heat exchanger degradation due to excessive flow-induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

The inspectors partially reviewed the licensee's performance testing of the UHS and cooling water (CL) system (which was the safety-related service water system) by completing Section 02.02.d.5.(a) of IP 71111-07. This was accomplished by reviewing the licensee's last performance test results for SP 1106B, "22 Diesel Driven Cooling Water Pump Monthly Test" completed on July 27, 2012; SP 1106C, "121 Motor Driven Cooling Water Pump CL Pump Refueling Outage Test," completed on April 16, 2012; and SP 1380, "CL-43-1 Discharge Check Valve Refueling Outage Test," completed on May 16, 2011. This inspection effort constituted a partial sample with Sections 02.02.d.5 (b) through (d) and 02.02.d.6 to be completed in a future inspection.

Lastly, the inspectors reviewed corrective action documents related to heat exchangers/coolers and UHS performance issues to verify that the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of the licensee's corrective actions. Documents reviewed are listed in the Attachment to this report.

These inspection activities constitute one heat sink inspection sample as defined in IP 71111.07-05.

b. Findings

Inadequate Past Operability Determinations for As-Found Component Cooling Heat Exchangers' Degraded Conditions

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," on August 15, 2012, due to the licensee's failure to adequately verify the adequacy of design by the performance of design reviews or by the use of alternate or simplified calculational methods. Specifically, the licensee failed to adequately evaluate the as-found condition of the 21 and 22 CC Water HXs to confirm the HXs had been capable of performing their safety function.

Description: On April 12, 2012 and May 14, 2012, the licensee opened and inspected the 21 and 22 CC Water HXs, respectively. On these dates, the 21 and 22 HXs were found to have approximately 123 and 176 tubes blocked by mud and silt which were in excess of the 61 blocked tubes allowed by Calculation ENG-ME-414, Revision 6C. The calculation limited the number of blocked tubes in a CC water HX to 61 to prevent the differential pressure across the divider plate from exceeding the design limit of 25 pounds per square inch differential (psid). Because of the excessive blockage, the licensee performed past operability determinations on the HXs as documented in Engineering Change (EC) 20044 (approved May 11, 2012) and EC 20222 (approved June 29, 2012) to verify the HXs in the as-found condition, would have performed the specified safety functions if a design basis accident (DBA) had occurred. During a DBA, the flow through the CC water heat exchangers would significantly increase; however, the licensee conservatively assumed the increased flow would not have pushed the mud or silt out of any of the tubes even though some of the tubes would probably have become unblocked. The licensee also estimated the blockage in the HXs would have caused the divider plate differential pressures to be approximately 27.3 and 29.5 psid, respectively. The licensee assumed the divider plates would plastically deform creating bypass flow paths when the divider plates' differential pressure design limit of 25 psid was exceeded. The licensee stated the thermal heat transfer capacity would be degraded but not lost and therefore the HXs did not have any loss of safety function. The licensee concluded in the ECs that the HXs remained operable in the as-found condition.

The inspectors noted the licensee did not identify whether the cause of the bypass paths would be from divider plate welds cracking or from divider plates bowing enough to allow gaps in the divider plate gasket areas. The inspectors noted that the ECs did not provide adequate technical justification to quantify or bound the amount of bypass flow or the amount of loss of thermal heat transfer capacity. Therefore, the inspectors questioned the past operability and reportability conclusions. On August 16, the licensee acknowledged the inspectors' concerns regarding insufficient technical evaluations in ECs 20044 and 20222. The licensee initiated Corrective Action Document (CAP) 1348544 to identify the cause and to recommend issuing new EC to assess past operability. The licensee stated the ECs should have referenced an event which occurred in 2008 where the 21 CC HX divider plate had bowed and caused bypass flow through the gasket areas. As documented in Apparent Cause Evaluation 1156737, the HX had passed the thermal performance test in 2008 with the bypass flow.

In addition, considering the magnitude of tubes found blocked in excess of the design limit after two fuel cycles, the inspectors questioned why the licensee had not modified the inspecting and cleaning frequency of the HXs from every other refueling outage to every refueling outage. The licensee stated the excessive blockage was likely the result of extensive dredging done near the plant intake during April and May of 2010 and that absent substantial river dredging, the inspect and clean frequency of every other refueling outage was reasonable. Since substantial river dredging is an expected activity during the plant life, the inspectors questioned whether procedures should require inspection and cleaning of the HXs in the event of substantial river dredging to ensure that excessive blockage would not occur in the CC Water HXs, any other HXs or components supplied by the CL system. The licensee initiated CAP 01349624 to document the inspectors' questions. This CAP recommended that flushing the HXs more frequently; inspecting and cleaning the HXs more frequently; modifying the CC water HXs to provide a more effective flush; and changing plant documents and/or programs to require opening, inspecting, and cleaning following major dredging near the plant intake be considered.

The licensee concluded by analysis and engineering judgment that the 21 and 22 CC Water HXs would have performed their specified safety functions if a DBA had occurred based on the ECs as supplemented by reasons specified in CAP 1348544, CAP 1349624, and other licensee documents.

<u>Analysis</u>: The failure to adequately evaluate the as-found condition of the 21 and 22 CC Water HXs to confirm the HXs had been capable of performing their safety function was contrary to 10 CFR 50, Appendix B, Criterion III, Design Control, and was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the Design Control attribute of the Mitigating Systems Cornerstone. This finding also affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings.” Because the finding impacted the Mitigating Systems, cornerstone, the inspectors screened the finding through IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” using Exhibit 2, “Mitigating Systems Screening Questions.” The finding screened as of very low safety significance (Green) because the finding was a qualification deficiency that did not represent a loss of operability or functionality. This finding was also determined to be cross-cutting in the Human Performance, Work Control area because the licensee did not properly ensure supervisory and management oversight of work activities such that nuclear safety was supported. Specifically, the licensee personnel reviewing and approving ECs 20044 and 20222 did not require the preparer to provide adequate technical support for the evaluations of past operability H.4(c).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design control measures shall provide for the verifying or checking the adequacy of design such as by the performance of design reviews or by the use of alternate or simplified calculational methods.

Contrary to the above, on May 11 and June 29, 2012, the licensee failed to perform adequate reviews to verify the adequacy of design of the 21 and 22 CC Water HXs. These HXs were required to mitigate the consequences of DBAs. Specifically, the licensee failed to provide adequate technical bases with respect to the impact of exceeding the divider plates’ differential pressure design limit when concluding that the 21 and 22 CC Water HXs would have fulfilled their safety functions during a DBA. As described above, the licensee initiated corrective actions as documented in CAP 1348544 and CAP 1349624. Because this violation was of very low safety significance and was entered into the licensee’s corrective action program, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2012004-01: Inadequate Past Operability Determinations for As-Found Component Cooling Heat Exchangers’ Degraded Conditions)**

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On September 18, 2012, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations 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)

On August 4, 2012, the inspectors observed the control room operators following an unexpected trip of a containment and auxiliary building chiller. This was an activity that required heightened awareness due to the subsequent increase in Unit 2 containment temperatures. 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;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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.

a. 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:

- Turbine and Moisture Separators; and
- D1 and D2 EDGs.

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 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 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:

- D1 and D2 EDGs OOS Due to Exhaust Manifold Fires From Gasket Leaks;
- D1 EDG OOS Due to Unplanned Limiting Condition for Operation (LCO); and
- Unit 2 Reactor Trip Bypass Breaker 2RT-5XA Failure.

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 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 three 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:

- Operability Recommendation (OPR) 1327157, Revisions 1 and 2 – Outside Air Temperature Operability Limits for the D1 and D2 EDGs;
- OPR 1353223 - Breaker 15-6 Conduit Support Gap and Loose Bolt; and
- OPR 1348106 - D2 EDG Exhaust Manifold Fire.

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 three 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:

- SP 2295 – D5 Diesel Generator Six Month Fast Start Test following maintenance on the D5 EDG;
- D2 EDG return to service test following maintenance;
- Unit 2 Reactor Trip Relay Train A following maintenance; and
- 12 Auxiliary Feedwater Discharge to 12 Steam Generator Motor Valve following maintenance.

These activities were selected based upon the structure, system, or component'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 and 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 four 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 the 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 1130A - Train A Containment Vacuum Breakers Quarterly Tests (Inservice Test);
- SP 1093 – D1 Diesel Generator Monthly Slow Start Test (Routine);
- SP 2090B – Unit 2 Containment Spray Pump Quarterly Test (Routine); and
- SP 1095 – Bus 16 Monthly Load Sequencer Test (Routine).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria 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 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 three routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections -02 and -05.

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 Mitigating Systems Performance Index - Emergency Alternating Current (AC) Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System performance indicator (PI) for Unit 1 and Unit 2 for the period from the third quarter 2011 through the second quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (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 database, event reports and NRC Integrated Inspection Reports for the period discussed 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 none were 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

No findings were identified.

.2 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for Unit 1 and Unit 2 for the period from the third quarter 2011 through the second quarter 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, corrective action database, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period discussed 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 none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Reactor Coolant System (RCS) Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage PI for Unit 1 and Unit 2 for the period from the second quarter 2011 through the second 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 logs, RCS leakage tracking data, corrective action database, event reports and NRC Integrated Inspection Reports for the period discussed 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 reactor coolant system leakage samples as defined in IP 71151-05.

b. Findings

No findings were identified.

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 reviews to verify that 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 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds (OWAs) on system availability and the potential for improper operation of the system, potential impacts on multiple systems, and the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment to this report were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: Review of Corrective Actions for Increased Leakage from Feedwater to Steam Generator Check Valve 2FW-8-2

a. Inspection Scope

The inspectors performed a containment tour, reviewed corrective action documents, and discussed equipment status with operations, engineering, and maintenance personnel to determine whether corrective actions proposed prior to the February 2012 2R27 outage would have prevented leakage on valve 2FW-8-2 which was identified in August 2012. Documents reviewed are listed in the Attachment to this report.

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

b. Observations and Findings

On August 8, 2012, the licensee performed Surveillance Procedure SP 2544, "Containment at Power Inspection." While performing the procedure, an operator found a large puddle of water on the floor approximately 10-15 feet by 5 feet on the 755 elevation of the Unit 2 containment. The water appeared to be originating from flashing below check valve 2FW-8-2. The licensee documented the leakage in CAP 1347517. The CAP documented the leak was dripping to the floor at a rate of 2-4 drops per second. The CAP further documented that a similar leak was identified on the same check valve at the beginning of 2R27 in February 2012.

The inspectors conducted a search of the licensee's corrective action database. The inspectors found that the licensee had initiated CAP 1326091 on February 22, 2012, due to water coming from the area of valve 2FW-8-2. In response to this CAP, the licensee performed a VT-2 inspection of feedwater and auxiliary feedwater piping leading up to the 22 steam generator. No evidence of active leakage was identified. Based upon the inspection results, the licensee concluded the pressure boundary function of the valve remained operable and that uneven thermal expansion was the cause. The licensee initiated WO 452214 to remove the piping insulation and torque the valve's hinge pin and cover retainer bolting.

The inspectors reviewed the above corrective action records, CAP 1347692, and the maintenance history for check valve 2FW-8-2. The inspectors found that the licensee had initiated WO 452698-01 to disassemble and inspect the check valve. However, this work was not performed since a subsequent VT-2 inspection performed during the refueling outage concluded that no active leaks were present. Operations personnel identified leakage on, or near, valve 2FW-8-2 during the Unit 2 startup. The licensee retorqued the valve bolting with the reactor at normal operating pressure and temperature which eliminated the leakage. The inspectors determined that the licensee's actions during and following the Unit 2 refueling outage were appropriate. No findings or NRC violations were identified because the valve leakage remained below procedural and regulatory limits.

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

.1 Unit 1 Required Shutdown due to D1 and D2 EDG Exhaust Fires

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled Unit 1 shutdown to affect repairs to EDGs D1 and D2. The outage began on August 14, 2012, and continued through August 20, 2012. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown, outage equipment configuration and risk management, electrical lineups, personnel fatigue management, startup, and identification and resolution of problems associated with the outage.

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

b. Findings

On August 13, 2012 at 9:39 a.m., operations personnel performed a scheduled monthly surveillance run of the D1 EDG. During this surveillance, the operators identified a small candle sized flame at the exhaust manifold. The D1 EDG was immediately shutdown. The shift supervisor entered TS 3.8.1 due to the D1 EDG being inoperable. Subsequent troubleshooting performed by the maintenance determined that the flame appeared to be caused by a gasket leak at the exhaust extension joint between the ring collector and the turbocharger.

As part of the ongoing review of this issue, TS 3.8.1 required the license to determine whether the remaining operable EDG was potentially inoperable due to a common cause failure. On August 14, 2012 at 2:30 a.m., the licensee ran the D2 EDG to verify whether a common cause failure existed. At 3:12 a.m., the Shift Manager reported a small candle sized fire on the exhaust manifold for the D2 EDG. The D2 EDG was subsequently declared inoperable and was shutdown. With both Unit 1 EDGs inoperable, TSs required that one EDG be returned to an operable status within 2 hours. If this was unable to be completed, the TSs directed that the Unit 1 reactor be shut down within six hours. The inspectors monitored the licensee's EDG restoration efforts. However, the licensee was unable to restore either the D1 or the D2 EDG to an operable status within two hours. As a result, operations personnel commenced shutting down the Unit 1 reactor at 4:30 a.m. on August 14, 2012.

The licensee documented the details regarding the D1 EDG fire in CAP 1348044. The inspectors monitored the licensee's corrective actions which included replacing the exhaust extension joint gaskets and removing/replacing the adjacent insulation. The licensee documented the D2 EDG exhaust fire in CAP 1348106. Corrective actions for this issue included torquing the exhaust extension joint flange bolts to reduce the amount of leakage and removing/replacing the adjacent insulation. Lastly, the licensee documented the D1 and D2 EDG common cause failure and the associated Unit 1 shutdown in CAP 1348310. Since both EDGs experienced similar fires, the inspectors were concerned that the condition of the exhaust extension joints/gaskets could have constituted a maintenance related issue. However, the licensee's evaluation regarding the cause of the fires had not been completed at the conclusion of the inspection. As a result, the inspectors were unable to conclude whether a performance deficiency existed. This issue was determined to be unresolved pending a review of the licensee's causal evaluations and a determination regarding whether a performance deficiency existed **(URI 05000282/2012004-02; Unit 1 Required Shutdown due to D1 and D2 Exhaust Fires)**.

.2 (Closed) LER 05000282/2011-001-02: Unplanned Actuation of 121 Motor Driven Cooling Water Pump, Supplement 2

On December 23, 2010, the licensee experienced an unplanned actuation of the 121 motor driven cooling water pump due to an unexpected shutdown of the 11 containment and auxiliary building chiller. The inspectors reviewed this issue and documented a traditional enforcement violation with an associated green finding in Section 4OA3.9 of NRC Inspection Report 05000282/2011004; 05000306/2011004. The inspectors reviewed the information contained in Supplement 2 of the LER and determined that the information did not change the original assessment contained in the above inspection report. Documents reviewed are listed in the Attachment to this report. This LER is closed.

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

4OA5 Other Activities

.1 (Discussed) Temporary Instruction (TI) 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 a 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, "Guidance for the Management of Underground Piping and Tank Integrity," (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 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.

The inspectors reviewed the licensee's programs for buried pipe and underground piping and tanks in accordance with TI-2515/182 to determine if the program attributes and completion dates identified in Sections 3.3 A and 3.3 B of NEI 09-14, Revision 1, were contained in the licensee's program and implementing procedures. For the buried pipe and underground piping program attributes with completion dates that had passed, the inspectors reviewed records to determine if the attribute was in fact complete and to determine if the attribute was accomplished in a manner, which reflected good or poor practices in program management. Documents reviewed are listed in the Attachment to this report.

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

b. Observations

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraphs 03.01.a through 03.01.c of TI-2515/182 and was found to meet all applicable aspects of NEI 09-14, Revision 1, as set forth in Table 1 of the TI.

c. Findings

No findings were identified.

.2 (Discussed) Unresolved Item (URI) 05000282/2012003-05: Impact of Outside Air Temperatures on D1 and D2 EDG Operability

a. Inspection Scope

The inspectors continued to monitor the licensee's actions to address the operability of the D1 and D2 EDGs due to extreme outside air temperatures. Specifically, the inspectors reviewed operations data to ensure that outside temperatures were appropriately monitored for potential impacts to the plant, observed licensee work activities associated with replacing the lube oil pressure switches on the D1 EDG, and ensured that appropriate actions were taken when outside air temperatures exceeded 97 degrees Fahrenheit ($^{0}$F) on July 2, 2012.

Documents reviewed are listed in the Attachment to this report.

b. Findings

As discussed in Section 1R01.4 of NRC Inspection Report 05000282/2012003; 05000306/2012003, the inspectors identified that the licensee had planned to increase the outside air temperature operability limits for the D1 and D2 EDGs without adequately assessing the impact of this increase on the most limiting component in the EDG rooms (the lube oil pressure switches). The inspectors discussed this concern with the licensee. In response to the inspectors' concern, the licensee stopped all activities associated with increasing the operability limits. This resulted in the outside air temperature operability limit for the D1 and D2 EDGs remaining at 97$^{0}$F as stated in OPR 1327157.

On June 30, 2012, the licensee replaced the lube oil pressure switches on the D2 EDG with switches that were qualified to operate at a higher temperature. The switch replacement resulted in the D2 EDG being capable of performing its safety function when outside air temperatures were higher than 97$^0$F. However, OPR 1327157 was not revised to reflect an increase in the D2 EDG outside air temperature operability limit.

At 3:31 p.m. on July 2, 2012, the licensee notified the NRC that the D1 and D2 EDGs were inoperable as required by 10 CFR Part 50.72. The EDG inoperability was caused by outside air temperatures exceeding 97$^0$F. The licensee immediately removed the D1 EDG from service to replace the lube oil pressure switch with a switch that could withstand a higher operating temperature. The licensee also took action to approve a revision to OPR 1327157 which increased the outside air temperature operability limit for the D2 EDG to 100.5$^0$F. The shift manager approved the OPR revision at 4:30 p.m. on July 2, 2012. The OPR revision approval allowed operations personnel to return the D2 EDG to an operable status within the two hours specified by TS Limiting Condition for Operation (LCO) 3.8.1, Condition F. The licensee returned the D1 EDG to an operable status at 7:46 p.m. on July 2, 2012.

On August 29, 2012, the licensee retracted the NRC notification made on July 2, 2012, based upon an evaluation showing that the D2 EDG would have been able to perform its safety function with the newly installed pressure switches. The inspectors reviewed the retraction and determined that it was appropriate. However, the licensee was continuing to evaluate the sequence of events which led to having to declare both EDGs inoperable on July 2, 2012. In addition, the licensee was testing the previously installed pressure switches to determine whether they would have operated at an increased outside air temperature at the conclusion of the inspection period. As a result, the inspectors were not able to determine whether a performance deficiency existed. The inspectors planned to review the licensee's causal evaluation, review the pressure switch testing results, and determine whether a performance deficiency existed when the licensee's information was available. As a result, this issue remained unresolved pending a review of the information discussed above.

.3 (Discussed) NRC TI 2515/187, Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns, and NRC TI 2515/188, Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns

a. Inspection Scope

The inspectors accompanied the licensee, on a sampling basis, during their seismic walkdowns to verify that the walkdown activities were conducted using NRC endorsed methodologies. These walkdowns are being performed at all sites in response to a letter from the NRC to licensees, entitled "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," dated March 12, 2012 (ADAMS Accession No. ML12053A340).

Enclosure 3 of the March 12, 2012, letter requested licensees to perform seismic walkdowns using an NRC-endorsed walkdown methodology. Electric Power Research Institute (EPRI) Document 1025286 titled, "Seismic Walkdown Guidance," (ADAMS Accession No. ML12188A031) provided the NRC-endorsed methodology for performing seismic walkdowns to verify that plant features credited in the current licensing basis (CLB) for seismic events were available, functional, and properly maintained. The licensee had not completed activities related to TI 2515/188 by the conclusion of the inspection period. The inspectors planned to complete the TI's inspection requirements during the 4th quarter of 2012.

Enclosure 4 of the letter requested licensees to perform external flooding walkdowns using an NRC-endorsed walkdown methodology (ADAMS Accession No. ML12056A050). Nuclear Energy Industry (NEI) Document 12-07 titled, "Guidelines for Performing Verification Walkdowns of Plant Protection Features," (ADAMS Accession No. ML12173A215) provided the NRC-endorsed methodology for assessing external flood protection and mitigation capabilities to verify that plant features credited in the CLB for protection and mitigation from external flood events were available, functional, and properly maintained. The licensee had not begun activities related to TI 2515/187 by the conclusion of the inspection period. The inspectors planned to accompany the licensee on their flooding walkdowns and complete the requirements provided in TI 2515/187 during the 4th quarter of 2012.

Documents reviewed during this inspection are provided in the Attachment to this report.

b. Findings

Findings or violations associated with the flooding and seismic walkdowns, if any, will be documented in Section 4OA5 of Prairie Island NRC Integrated Inspection Report 5000282/2012005; 05000306/2012005.

.4 (Closed) Unresolved Item 05000306/2012007-01: Number of Air Receivers Required to be Greater than 480 pounds per square inch (psig) to Support EDG Operability

a. Inspection Scope

As discussed in Section 4OA2.1 of NRC Inspection Report 05000282/2012007; 05000306/2012007, the NRC identified a concern regarding the number of air receivers required to be greater than 480 psig to support D5 and/or D6 EDG operability. The inspectors reviewed USAR and design basis information, operating procedures, maintenance rule documents, and ECs 20717, "Station Position on D5 and D6 Emergency Diesel Generator Operability with Regards to the Number of Operable Starting Air Receivers," and 20927, "D5/D6 EDG Availability with Regards to the Number of Charged Starting Air Receivers," to determine whether the licensee complied with operability and availability requirements following a failure of two air receivers on October 15, 2010. The inspectors also reviewed maintenance rule documents to determine whether conditions associated with the D5 and D6 EDGs, and their respective air receivers, had been appropriately evaluated under the licensee's maintenance rule program.

Documents reviewed during this inspection are provided in Attachment to this report.

b. Findings

On October 15, 2010, the licensee initiated CAP 1254304 to document that the D6 EDG 2A starting air compressor relief valve (2EG-39-7) was leaking. This condition caused the pressure in the 2A starting air receiver to drop below 480 psig. Upon identifying this condition, the operators checked the operating status of the remaining three air receivers and determined that the 1A receiver was also less than 480 psig due to planned maintenance on the 1A starting air compressor. The operations crew immediately declared the D6 EDG inoperable since Alarm Response Procedures (ARPs) C50001, “D5 Engine 1 Remote Alarm Responses,” and C60001, “D6 Engine 1 Remote Alarm Responses,” contained a note which stated that the pressure in three out of four air receivers must be greater than 480 psig to maintain EDG operability.

During the 2012 Problem Identification and Resolution Inspection, the inspectors reviewed actions taken by the licensee in response to CAP 1254304. The inspectors reviewed a maintenance rule evaluation connected to the CAP and discovered that the condition discussed above was not classified as a maintenance rule functional failure. The maintenance rule conclusion was based upon USAR information which stated that only two air receivers were needed to support D5 or D6 EDG operability. The inspectors questioned the conflicting information provided in the USAR and the ARP. This led to opening URI 05000306/2012007-01.

On September 11, 2012, the licensee completed EC 20717 to officially document the number of air receivers required to be greater than 480 psig to support EDG operability. The inspectors reviewed the EC and concluded that three air receivers needed to remain greater than 480 psig for the associated EDG to support the five consecutive starts criteria and remain operable. As a result, the inspectors determined that operations personnel had correctly declared the D6 EDG inoperable on October 15, 2010. The inspectors also reviewed vendor pre-operational testing results and information provided in EC 20927 regarding the equipment needed to support availability of the D6 EDG. The inspectors concluded that the D6 EDG could be considered available as long as the air start system provided adequate air to the EDG to support one start. Since the criteria was also met, the licensee’s determination that the D6 EDG was inoperable but available following the October 15, 2010, 2A starting air compressor relief valve issue was appropriate and performed in accordance with maintenance rule requirements. No performance deficiencies were identified because the licensee met both TS and maintenance rule requirements following the discovery of issues associated with the 2A starting air compressor relief valve.

This item is considered closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 11, 2012, the inspectors presented the inspection results to J. Sorensen, Acting 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 Mr. S. Sharp, Plant Manager, and other members of the licensee staff on May 11, 2012.

- On October 9, 2012; the inspectors presented in an interim exit meeting for the Triennial Heat Sink inspection to Scott Sharp, Plant Manager; Paul Huffman, Site Engineering Director and other members of the licensee staff.

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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

J. Sorensen, Acting Site Vice President
K. Davison, Director – Site Operations
P. Huffman, Site Engineering Director
S. Sharp, Plant Manager
R. Madjerich, Assistant Plant Manager
T. Allen, Senior Manager Site Engineering
J. Anderson, Regulatory Affairs Manager
J. Boesch, Maintenance Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
K. DenHerder, Buried Pipe Program Owner (Back-Up)
D. Gauger, Chemistry Manager
J. Hamilton, Security Manager
B. Horner, Component Cooling System Engineer
S. Kardian, Buried Pipe Program Owner
S. Kerins, former Cooling Water System Engineer
J. Lash, Nuclear Oversight Manager
S. Lappegaard, Production Planning Manager
J. Loeffler, Mechanical Design Engineer
K. Peterson, Business Support Manager
D. Potter, Programs Engineering Manager
A. Pullam, Training Manager
J. Ricker, Inspections and Materials Supervisor
J. Ruttar, Operations Manager
S. Schibonski, Cooling Water System Engineer

Nuclear Regulatory Commission

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

## LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000306/2012004-01 | NCV | Failure to Perform Adequate Past Operability Evaluations After Discovering Degraded Component Cooling Heat Exchangers (Section 1R07) |
| 05000282/2012004-02 | URI | Unit 1 Required Shutdown due to D1 and D2 Emergency Diesel Generator Exhaust Fires (Section 4OA3.1) |

Closed

| | | |
|---|---|---|
| 05000306/2012004-01 | NCV | Failure to Perform Adequate Past Operability Evaluations After Discovering Degraded Component Cooling Heat Exchangers (Section 1R07) |
| 05000282/2011-001-02 | LER | Unplanned Actuation of 121 Motor Driven Cooling Water Pump, Supplement 2 (Section 4OA3.2) |
| 05000306/2012007-01 | URI | Number of Air Receivers Required to be Greater than 480 pounds per square inch (psig) to Support EDG Operability (Section 4OA5.4) |

Discussed

| | | |
|---|---|---|
| 2515/182 | TI | Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (Section 4OA5.1) |
| 05000282/2012003-05 | URI | Impact of Outside Air Temperatures on D1 and D2 Emergency Diesel Generator Operability (Section 4OA5.2) |
| 2515/187 | TI | Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns (Section 4OA5.3) |
| 2515/188 | TI | Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns (Section 4OA5.3) |

## LIST OF DOCUMENTS REVIEWED

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

### 1R01 Adverse Weather

- CAP 1327157; Potential Non-Conservative Heat Up Analysis for D1/D2; February 29, 2012
- Emergency Response Computer System Meteorological Temperature Data; various dates
- NRC Event Notification 46934; Both Emergency Diesel Generators Declared Inoperable due to Excess Outside Air Temperatures; August 1, 2011
- Operability Recommendation 1327157; Outside Air Temperature Limits for D1/D2; Revision 0
- Engineering Change 19915; D1/D2 Room Relay Cabinet Temperature Evaluation; Revision 0
- Engineering Change 20055; Past Operability for Heat-Up Analysis for D1/D2 for Revised Outside Air Temperature Limit from Operability Recommendation 1327157, Revision 0; June 10, 2012

### 1R04 Equipment Alignment

- C1.1.20.7-16; D6 Diesel Generator Circuit Breakers and Panel Switches; Revision 8
- C1.1.20.7-15; D6 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 6
- C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 12
- C1.1.20.7-8; D2 Diesel Generator Circuit Breakers and Panel Switches; Revision 16
- C1.1.20.7-7; Diesel Generator D2 Main Control Room Switch and Indicating Light Status; Revision 13
- C1.1.20.7-6; D2 Diesel Generator Auxiliaries and Room Cooling Local Panel; Revision 11
- C1.1.20.7-13; D6 Diesel Generator Valve Status; Revision 15
- C1.1.20.7-5; D2 Diesel Generator Valve Status; Revision 23
- C1.1.35-3; Cooling Water System; Revision 31

### 1R05 Fire Protection

- CAP 1350619; Old Wood Spotted In Overhead of Bus 25 Room; September 7, 2012
- NSPLMI-96001, “Prairie Island Nuclear Generating Plant Individual Plant Examination of External Events (IPEEE),” Revision 1
- Operations Manual Procedure F5, “Fire Fighting,” Appendix A, “Fire Fighting Strategies,” Revision 28
- Operations Manual Procedure F5, “Fire Fighting,” Appendix F, “Fire Hazard Analysis,” Revision 26

### 1R06 Flood Protection

- CAP 1345525; Unit 2 High Energy Line Break Flooding Barrier Removed with Unit 2 at Power; July 20, 2012
- CAP 1346759; D5/D6 Trench Covers not Considered in High Energy Line Break Flooding Analysis; August 1, 2012

1R07 Heat Sink Inspection

- Calculation 99-131; Determination of CC HX Design Basis; July 23, 2009
- CAP 1332503; Degraded gasket found on 21 CC HX endbell; April 6, 2012
- CAP 1337547; 22 CC HX inspection found higher-than-expected tube blockage; May 14, 2012
- CAP 1347293; H21, Generic Letter 89-13 Implementing Program, requires revision; August 6, 2012
- CAP 1347294; SP 1304 and 2340 require stable to be defined; August 6, 2012
- CAP 1347295; Backlog of PINGP 1066 trending results; August 6, 2012
- CAP 332433; 21 CC HX inspection found higher-than-expected tube blockage; April 6, 2012
- EC 20044; 21 CC Hx as found degradation Past Operability Evaluation; May 14, 2012
- EC 20222; 22 CC Hx as found degradation Past Operability Evaluation; July 2, 2012
- PINGP 1066; 21 CC Hx inspection results form; April 8, 2012
- PINGP 1066; 22 CC Hx inspection results form; May 12, 2012
- SnapShot Self-Assessment/AR 01318461-02; 21 & 22 CC HXs reviewed against new IP 71111-07T; August 6, 2012
- SP 1380 CL-43-1 11MDCLP Dsch Ck Refueling Test; May 16, 2011
- SP 2304 Unit 2 CC Hx performance tests; March 13, 2012
- WO 00395866; SP 1380 CL-43-1 RFO test; May 16, 2011
- WO 00427539; SP 1106C 121 CL Pump Test; April 14, 2012
- WO 00437086; SP 1106B 22 Diesel CL pump monthly test; July 27, 2012
- WO 409819; SP 2304 Unit 2 CC Hx performance tests; March 13, 2012
- YUBA CC HX spec sheets; April 30, 1970
- YUBA CC HX spec sheets; November 2,1996

1R12 Maintenance Effectiveness

- ACE 1167382/1174714; D1 Diesel Generator Inoperable Due to Fire and Jacket Coolant Leak; Revision 1
- Apparent Cause Evaluation 1292975; Unit 1 Reactor Trip; July 1, 2011
- CAP 1138187; Fires Involving Emergency Diesel Generator Exhaust Manifolds – NRC Information Notice 2008-05; August 26, 2008
- CAP 1348106; D2 Exhaust Fire; August 14, 2012
- EC 20600; Basis for Determination of D2 Diesel Generator Operability; August 16, 2012
- Fairbanks Morse Marketing Information Letter #46B; Non-Asbestos Exhaust Gaskets for 8-1/8 Turbocharged O.P.; October 7, 1992
- Maintenance Rule a(1) Action Plan; Turbine and Moisture Separator System; November 8, 2011
- PM 3001-2-D1; D1 Diesel Generator Inspection (034-011); Revision 31
- Root Cause Evaluation 1227647; Unit 2 Turbine Trip during Reactor Shutdown; April 16, 2010
- Root Cause Evaluation 1326556; Repetitive Reactor Trips due to Feedwater Heater High Levels; July 20, 2012
- SP 1305; D2 Diesel Generator Monthly Slow Start Test; Revision 45
- WO 109388; P3001-2-D1 - D1 Diesel Generator 18 Month Inspection; January 26, 2007
- WO 368814; D2 EDG – Replace Gaskets on Bottom Exhaust Gas Collector Plates CS & OCS; October 14, 2009
- WO 381231; Mech: Disassemble Exhaust Piping – D1; March 26, 2009
- WO 383217; Mech: Disassemble Exhaust Piping – D1; April 26, 2009
- WO 384041; Replace D2 Exhaust Manifold Exhaust Extension Gasket; October 7, 2009
- WO 415127; D2 EDG Exhaust Manifold Insulation Blanket Replacement; May 21, 2011
- WO 439434; Mech: Disassemble the Exhaust Piping on CS and OCS – D1; August 13, 2012

- WO 464039; Mech: Disassemble the Exhaust piping on CS and OCS – D2; August 14, 2012
- XH-28-44; Vendor Technical Manual – Fairbanks Morse Diesel Generator Set; Various Revisions

1R13 Maintenance Risk Assessment and Emergent Work

- CAP 1348106; D2 Exhaust Manifold Fire; August 14, 2012
- CAP 1350074; Reactor Trip Bypass Breaker (1-52/BYB) Functionality; August 30, 2012
- FP-OP-PEQ-01; Protected Equipment Program {C001}; Revision 7
- FP-WM-IRM-01; Integrated Risk Management; Revision 7
- H24.1 Appendix A; Phase 1 Risk Assessment Preparation; Revision 6
- H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 15
- SWI O-59; Protected Equipment Program; Revision 7
- Work Schedules and Daily Risk Assessment Results; various dates

1R15 Operability Evaluations

- Apparent Cause Evaluation AR 01167382-01/01174714-03, "Exhaust Manifold Fires on D1 Diesel Generator," (2009)
- CAP 1348106; D2 Exhaust Manifold Fire; August 14, 2012
- CAP 1353223; 2012 Fukushima: Gap on Conduit Support Possible Loose Bolt; September 27, 2012
- EC 20600, "Basis for Determination of D2 Diesel Generator Operability," August 16, 2012
- NRC Information Notice 2008-05, "Fires Involving Emergency Diesel Generator Exhaust Manifolds," April 12, 2008
- Operating Experience Evaluation AR 01138187-01, "NRC Information Notice 2008-05"

1R19 Post Maintenance Testing

- CAP 1348106; D2 Exhaust Fire; August 14, 2012
- CAP 1350074; Reactor Trip Bypass Breaker (1-52/BYB) Functionality; August 30, 2012
- Plant Impact statement; Work Order 464287; No Date
- Reactivity Management Checklist; Work Order 464287; August 24, 2012
- SP 2035A; Reactor Protection Logic Test At Power – Train A; Revision 41
- WO 464287; 2RT-5XA – Reactor Trip Relay Train A; August 23, 2012
- Work Plan 464287; Reactor Trip Relay Train A; August 23, 2012
- X-HIAW-1001-1405; Reactor Trip Breakers; Revision 76
- X-HIAW-1001-1406; Reactor Trip Breakers; Revision 76

1R22 Surveillance Test

- Operations Manual Procedure H10.1, "ASME [American Society of Mechanical Engineers] Inservice Testing Program," Revision 30
- Prairie Island Nuclear Generating Plant Technical Specifications
- SP 1093; D1 Diesel Generator Monthly Slow Start Test; Revision 89
- SP 1095; Bus 16Load Sequencer Test; Revision 33
- SP 1130A; Train A Containment Vacuum Breakers Quarterly Tests; Revision 11
- SP 2090B, "22 Containment Spray Pump Quarterly Test," Revision 19
- WO 437729; SP1093 – D1 Diesel Generator Monthly Slow Start Test; August 13, 2012

- WO 437749; SP1130A – Train A Containment Vacuum Breakers Quarterly Tests; August 8, 2012
- WO 438366; SP 1095 Bus 16 Load Sequencer Test; August 24, 2012
- WO 438674; SP 2090B 22 Containment Spray Pump Quarterly Test; August 15, 2012

4OA1 Performance Indicator Verification

- Limiting Condition for Operations Log; various dates
- Operations Narrative Logs; various dates
- PINGP 1614; Unit 1 Emergency AC MSPI Monthly Data; various dates
- Prairie Island Unit 1 MSPI Derivation Report – Cooling Water; various dates
- Prairie Island Unit 1 MSPI Derivation Report – Emergency AC Power System; various dates
- Prairie Island Unit 2 MSPI Derivation Report – Cooling Water; various dates
- Prairie Island Unit 2 MSPI Derivation Report – Emergency AC Power System; various dates

4OA2 Identification and Resolution of Problems

- CAP 1326091; Water Reported Coming From the Area of 2FW-8-2; February 22, 2012
- CAP 1347517; Leak on Check Valve or Near 2FW-8-2; August 08, 2012
- CAP 1347692; Maintenance History Review 2FW-8-2 FW to 22 SG Check; August 09, 2012
- CAP 1349542; Revise the QF-1118 Form as Indicated on the Attached Mark-up; August 26, 2012
- FP-OP-OB-01; Operator Burden Program; Revision 3
- ODMI 1347517; Operational Decision Making Evaluation – Unit 2 2FW-8-2 Feedwater Check Valve Hinge Pin Flange Leaks in Containment; August 10, 2012
- Operator Burden Report; September 11, 2012
- QF-1118; 2R27 Outage Scope Change Request Number 915; April 14, 2012
- WO 452214; Water Reported Coming From The Area of 2FW-8-2; April 9, 2012
- WO 452698; 2FW-8-2 Check Valve Disassembly & inspection Per H12; March 6, 2012

4OA3 Followup of Events and Notices of Enforcement Discretion

- 1C1.2; Unit 1 Startup Procedure; Revision 53
- 1C1.4 AOP!; Rapid Power Reduction – Unit 1; Revision 10
- 1E-0; Reactor Trip or Safety Injection; Revision 29
- C1B; Appendix – Reactor Startuo; Revision 19
- CAP 1348044; D1 Control Side Turbocharger Gasket Leak; August 13, 2012
- CAP 1348106; D2 Exhaust Manifold Fire; August 14, 2012
- CAP 1348310; Unplanned Unit 1 Shutdown due to Common Cause D1/D2 Failures; August 15, 2012
- FIG C1A-3; Estimated Critical Boron Concentration Based on Simulate Code; Revision 9
- MRE 1348044; Maintenance Rule Evaluation – D1 Control Side Turbocharger Gasket Leak; September 7, 2012
- MRE 1348106; Maintenance Rule Evaluation – D2 Exhaust Manifold Fire; September 7, 2012
- Reactivity Plan; Prairie Island Unit 1 Cycle 27 Power Ascension Following 1F2702HS, D1/D2 Exhaust Manifold Issues; Revision 1

4OA5 Other Activities

- Apparent Cause Evaluation 1254304-07; November 30, 2010
- CAP 1267747; NEI 09-14 Revision 1, Procedures and Oversight Milestones; January 25, 2011

- CAP 1300370; D6 Generator Trip; August 22, 2011
- CAP 1337180; Enhancement Opportunities from TI 2515/182; May 10, 2012
- CAP 1343465; Questions Raised During OPR for D1/D2 Maximum Outside Air Temperature; June 29, 2012
- CAP 1343845; Past Operability Determination for D1/D2 Room Heatup Calculation Not Timely; July 4, 2012
- CAP 1354593; Maintenance Rule Evaluation on D6 Availability with Two Air Receivers Inadequate; October 10, 2012
- CD 5.39; Fleet Buried Pipe and Tank Integrity Program Standard; Revision 2
- CSI Report No. 2200.101-02; Buried Piping Inspection Plan; Revision 1
- FL-ESP-PGM-063M; Underground Piping and Tank Integrity (UPTI) Program Owner (Mentoring/Position Specific Guide); Revision 2
- FP-PE-PHS-01; Program Health Process; Revision 13
- H58; Underground Piping and Tank Integrity Program; Revision 1
- Maintenance Rule Evaluation 1254304-01; 2EG-39-7 Leaking By; no date provided
- Maintenance Rule Evaluation 1300370-02; D6 Generator Trip; no date provided
- Monthly Maintenance Rule Performance Report; August 2011
- PING 1699; Underground Pipe or Tank Inspection Form; Revision 0
- Prairie Island Maintenance Rule System Specific Basis Document

## LIST OF ACRONYMS USED

| | |
|---|---|
| AC | Alternating Current |
| ADAMS | Agencywide Document Access Management System |
| ATTN | Attention |
| ARP | Alarm Response Procedure |
| CAP | Corrective Action Program |
| CC | Component Cooling |
| CFR | Code of Federal Regulations |
| CL | Cooling Water |
| CLB | Current Licensing Basis |
| DBA | Design Basis Accident |
| $^{0}$F | Degrees Fahrenheit |
| DDCLP | Diesel Driven Cooling Water Pump |
| EC | Engineering Change |
| EDG | Emergency Diesel Generator |
| EPRI | Electric Power Research Institute |
| HELB | High Energy Line Break |
| IMC | Inspection Manual Chapter |
| IP | Inspection Procedure |
| IPEEE | Individual Plant Examination of External Events |
| IR | Inspection Report |
| IST | Inservice Test |
| LCO | Limiting Condition For Operation; |
| LER | Licensee Event Report |
| MSPI | Mitigating Systems Performance Index |
| NCV | Non-Cited Violation |
| NEI | Nuclear Energy Institute |
| NRC | U.S. Nuclear Regulatory Commission |
| OOS | Out of Service |
| OPR | Operability Recommendation |
| OWA | Operator Workarounds |
| PARS | Publicly Available Records System |
| PI | Performance Indicator |
| PSID | Pounds per Square Inch Differential |
| PSIG | Pounds per Square Inch |
| RCS | Reactor Coolant System |
| SDP | Significance Determination Process |
| SSC | Structures, Systems, and Components |
| TI | Temporary Instruction |
| TS | Technical Specification |
| UHS | Ultimate Heat Sink |
| URI | Unresolved Item |
| USAR | Updated Safety Analysis Report |
| WO | Work Order |

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Sincerely,

*/RA/*

Kenneth Riemer, Branch Chief
Branch 2
Division of Reactor Projects

Docket Nos.: 50-282; 50-306; 72-010
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SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2; NRC INTEGRATED INSPECTION REPORT 05000282/2012004; 05000306/2012004

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