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

November 4, 2010

Mr. Mark A. Schimmel
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 05000282/2010004; 05000306/2010004

Dear Mr. Schimmel:

On September 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed a baseline 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 7, 2010, 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.

Based on the results of this inspection, one NRC-identified finding of very low safety significance was identified. The finding involved a violation of NRC requirements. However, because of its very low safety significance, and because the issue was entered into your corrective action program, the NRC is treating the issue as a Non-Cited Violation (NCV) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, two licensee identified violations are listed in Section 4OA7 of this report.

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 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 document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2010004; 05000306/2010004
w/Attachment: Supplemental Information

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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:	05000282/2010004; 05000306/2010004
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	July 1 through September 30, 2010
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector D. Betancourt, Reactor Engineer N. Feliz-Ordorno, Reactor Engineer M. Phalen, Senior Health Physics Inspector C. Thomas, Senior Resident Inspector - Monticello
Approved by:	John B. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000282/2010004; 05000306/2010004; 7/1/2010 – 9/30/2010; Prairie Island Nuclear Generating Plant, Units 1 and 2; Event Follow-up.

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. A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors on July 12, 2010, due to the failure to establish measures to assure that applicable regulatory requirements and the design basis for the residual heat removal (RHR) system were correctly translated into specifications, drawings, procedures and instructions. Specifically, the licensee failed to have appropriate procedures in place to ensure that the safety function of the RHR system was maintained following valve repositioning to support transitioning from the decay heat removal mode of RHR to providing suction from the refueling water storage tank (RWST) or following a Mode 4 loss of coolant accident. The licensee entered the issue into their corrective action program and revised procedures to address the issue.

  This performance deficiency was determined to be more than minor because it was associated with the Mitigating System Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this issue was of very low safety significance, using IMC 0609 Appendix G for shutdown risk issues, because other systems were available for injection into the reactor coolant system and feed the steam generators; and due to the extremely low probability of a large loss of coolant accident during Mode 4 operations. This finding had no cross-cutting aspect since there was no performance characteristic from IMC 0310 that was a significant contributor to the performance deficiency. (Section 4OA3.3).

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at full power throughout the inspection period.

Unit 2 operated at or near the full power level with the following exceptions:

- On September 18, reactor power increased to 100.01 percent due to erratic operation of a controller for a 1B reheater drain tank valve to the B condenser. Operations personnel reduced reactor power, stabilized the plant, and took additional actions to ensure that the controller's operation would not result in reactor power increasing above 100 percent.
- On September 28, operations personnel lowered Unit 2 reactor power to 95 percent for approximately 48 hours to perform planned maintenance on the 21 and 22 heater drain tank pumps.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Watch

a. Inspection Scope

On July 14, 2010, the National Weather Service issued a tornado warning for areas near the plant. Upon activation of the licensee's adverse weather emergency response system, the inspectors responded to the control room to review the operators' response to the weather conditions. The inspectors observed operations personnel monitoring weather conditions, obtaining additional control room staff to monitor plant indications that could change due to adverse weather conditions, and reviewing procedures in preparation for equipment challenges caused by the adverse weather. The inspectors determined that operator actions were as specified by procedures.

The inspectors also reviewed a sample of corrective action program (CAP) items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP program in accordance with procedures. Specific documents reviewed during this inspection are listed in the Attachment.

This inspection constituted one readiness for an impending adverse weather condition sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

.2 External Flooding

a. Inspection Scope

On September 24, 2010, operations personnel entered Abnormal Operating Procedure AB-4, “Flood,” due to the 3 day forecasted river level being greater than 678 feet. The inspectors reviewed the abnormal operating procedure and the compensatory measures needed to mitigate the predicted flooding conditions to ensure they could be implemented as written. The inspectors evaluated the design and material condition of equipment used to mitigate flooding conditions and toured low lying areas to identify potential in-leakage. The inspectors also performed a walkdown of the protected area to identify any modifications to the site which would inhibit site drainage during the predicted flood conditions or allow water ingress past a barrier. Operations personnel remained in Procedure AB-4 at the conclusion of the inspection period. No significant flooding had been experienced at the station during the inspection period. Documents reviewed during this inspection are listed in the Attachment.

This inspection will not be counted as an inspection sample because the sample was credited during a similar inspection performed in March 2010.

b. Findings

No findings of significance were identified.

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:

- D5 Diesel Generator Building Heating, Ventilation, and Air Conditioning, and
- 122 Control Room Chiller.

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, the Updated Safety Analysis Report (USAR), Technical Specification (TS) requirements, outstanding work orders (WOs), CAPs, 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 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 CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted two partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

Potential Inadequate Protection of 122 Control Room Chiller

Introduction: The inspectors identified an unresolved item (URI) concerning the ability of the licensee's maintenance planning and protected equipment processes to adequately protect safety-related equipment from failure while performing maintenance activities on redundant and/or support equipment.

Description: On August 31, 2010, the inspectors performed a partial equipment alignment of the 122 Control Room Chiller due to maintenance being conducted on both the Bus 111 Unit Cooler and 121 Control Room Chiller. The 122 Control Room Chiller was considered to be protected equipment. During the walkdown, the inspectors noted that the suction pressure for the 122 Control Room Chiller Pump was less than the pressure band specified in the operating procedure and was steadily decreasing. The inspectors immediately contacted the control room to inform them of the decreasing pump suction pressure. The control room dispatched local operators to the scene to re-pressurize the system. In addition, maintenance workers in the Bus 111 room were contacted and told to stop all work activities. Operator actions to re-pressurize the system prevented the pump from tripping due to low suction pressure. Had the pump tripped, operations personnel may have been required to enter TS 3.0.3 for both units. The licensee entered the unexpected decrease in the pump suction pressure into the CAP as CAP 1247908. The licensee also planned to review whether deficiencies in work planning and/or the protected equipment program contributed to the decrease in pump suction pressure. As a result, this item was considered to be unresolved pending a review of the licensee's corrective action evaluations (URI 05000282/2010004-01; 05000306/2010004-01; Review Licensee's Evaluation of 122 Control Room Chiller Issue to Determine Whether Performance Deficiency Exists).

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:

- Relay and Cable Spreading Room (Fire Zone 12 / Fire Area 18);
- Bus 112 and Train A Event Monitoring Rooms (Fire Zone 26 / Fire Area 79);
- Bus 15 and 16 Switchgear Rooms (Fire Zone 11 / Fire Area 81);
- 4 Kilovolt Bus 25 Room (Fire Zone 97 / Fire Area 117);
- 4 Kilovolt Bus 26 Room (Fire Zone 97 / Fire Area 118); and
- D5 480 Volt Switchgear 211 and 212 Room (Fire Zone 97 / Fire Area 127).

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. Using the documents listed in the Attachment, 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 of significance were identified.

1R06 Flooding (71111.06)

.1 Underground Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk significant equipment. The inspectors determined that the cables were not submerged, that splices were intact, and that appropriate cable support structures were in place. In those areas where dewatering devices were used, such as a sump pump, the device was operable and level alarm circuits were set appropriately to ensure that the cables would not be submerged. In those areas without dewatering devices, the inspectors verified that drainage of the area was available, or that the cables were qualified for submergence conditions. The inspectors also reviewed the licensee's corrective action documents with respect to past submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walk down of the following underground bunkers/manholes subject to flooding:

- D4 Underground Cable Vault

This inspection constituted one underground vault sample as defined in IP 71111.06-05.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On August 3, 2010, 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 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 sample as defined in IP 71111.11.

b. Findings

No findings of significance 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:

- Containment Vent, and
- Containment and Auxiliary Building Cooling.

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 of significance 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:

- Removal of 121 motor-driven cooling water pump due to coupling failure;
- Risk Assessment for week of August 8, 2010, which included emergent maintenance on the cooling water system; and
- Emergent work due to a Unit 2 Yellow Channel Tave bistable 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.

These maintenance risk assessments and emergent work control activities constituted three samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operability Review (OPR) 1237113; Safeguards Battery Room Door Seal;
- OPR 1241732; Unit 1 Gas Void in Safety Injection/Residual Heat Removal;
- OPR 1238829; Radiation Monitor R-11 Ability to Detect Leakage;
- CAP 1237728; Adequacy of Tornado Missile Protection for D1 and D2 Diesel Generators; and
- OPR 1246406; Steam Generator Blowdown Margin.

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 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 five samples as defined in IP 71111.15-05.

b. Findings

No findings of significance were identified.

.2 Operability Evaluations Associated with Temporary Instruction 2515/177; Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

a. Inspection Scope and Documentation

The inspectors reviewed the following issue associated with the scope of Generic Letter (GL) 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems”:

- OPR 1241732; Unit 1 Gas Void in Safety Injection/Residual Heat Removal.

The inspectors verified that the licensee had acceptably identified the gas intrusion mechanisms that applied to the plant. If the licensee’s evaluation was incomplete, the inspectors verified that corrective actions were placed into the CAP (Temporary Instruction (TI) 2515/177, Section 04.02.e). In addition, the inspectors verified that the licensee’s void acceptance criteria were consistent with the Office of Nuclear Reactor Regulations’ (NRR) void acceptance criteria. If NRR’s acceptance criteria were not met, then the inspectors verified that the licensee had justified the deviation. Also, the inspectors confirmed that (1) the licensee had addressed the effect of pressure changes during system startup and operation since such changes could significantly affect the void fraction from the initial value; and (2) the range of flow conditions evaluated by the licensee was consistent with the full range of design basis and expected flow rates for various break sizes and locations (TI 2515/177, Section 04.02.f).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counts towards the completion of TI 2515/177 which will be closed in a later inspection report.

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 1074A/1081.1; 121 Auxiliary Building Special Ventilation Test;
- SP 1095; Bus 16 Load Sequencer Test;
- SP 2305; D6 Diesel Generator Monthly Slow Start Test;
- TP 1745; D3 Diesel Generator Functionality Monthly Test;
- SP 1106C; 121 Cooling Water Pump Test; and
- SP 1112; Steam Exclusion Monthly Damper Test.

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 TS, 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 six post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings of significance 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 1090A; 11 Containment Spray Pump Quarterly Test (Inservice Testing);
- SP 1094; Bus 15 Load Sequencer Test;
- SP 1093; D1 Slow Start Test;
- SP 2090B; 22 Containment Spray Pump Quarterly;
- SP 2258B; Bus 26 Sequencer Load Rejection and Restoration of 122 Control Room Chiller; and
- TP 2468; Unit 2 GL 2008-01 Inspections (TI 2515/177 effort).

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 (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 five routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

.2 Surveillance Testing Associated with Temporary Instruction 2515/177; Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

a. Inspection Scope

The inspectors observed engineering personnel perform ultrasonic testing to assess potential changes to Unit 2 void conditions for the residual heat removal system as discussed in GL 2008-01. The ultrasonic examination was used to determine the presence of a void and/or whether the licensee's void elimination methods were effective.

The inspectors reviewed the procedures used for determination of void volumes to ensure that the void criteria was satisfied and will be reasonably ensured to be satisfied until the next scheduled void examination (TI 2515/177, Section 04.03.a). Specifically, the inspectors verified that:

- Gas intrusion monitoring, trending, evaluation, and void correction activities were acceptably controlled by approved operating procedures (TI 2515/177, Section 04.03.c.1); and that
- The licensee entered changes into the CAP as needed to ensure acceptable response to issues. In addition, the inspectors confirmed that a clear schedule for completion is included for CAP entries that have not been completed (TI 2515/177, Section 04.03.c.5).

The inspectors verified the following with respect to void detection:

- Procedures included up-to-date acceptance criteria (TI 2515/177, Section 04.03.d.4).
- Measured void volume uncertainty was considered when comparing test data to acceptance criteria (TI 2515/177, Section 04.03.d.6).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counts towards the completion of TI 2515/177 which will be closed on a later Inspection Report.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency preparedness drill on July 27, 2010, to identify any weaknesses or deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Simulator, Emergency Operating Facility, and Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee's critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them 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 of significance were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

These inspection activities supplement those documented in Inspection Report 05000282/2010002; 05000306/2010002, and constitute one complete sample as defined in IP 71124.01-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators (PIs) for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed the results of radiation protection program audits (e.g., licensee's quality assurance audits or other independent audits). The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings of significance were identified.

.2 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors determined if there have been changes to plant operations since the last inspection that may result in a significant, new radiological hazard for onsite workers or members of the public. The inspectors evaluated whether the licensee assessed the potential impact of these changes and had implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from three selected plant areas. The inspectors evaluated whether the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

The inspectors selected the following three radiologically risk-significant work activities that involved exposure to radiation.

- Radioactive waste storage and processing;
- Unit 2 containment inspection in support of gas intrusion into the reactor coolant system; and
- Operations walkdowns.

For these work activities, the inspectors assessed whether the pre-work surveys performed were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the radiological survey program to determine if hazards were properly identified, including the following:

- the identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials. (This evaluation may include licensee planned entry into non-routinely entered areas subject to previous contamination from failed fuel.);
- the hazards associated with work activities that could suddenly and severely increase radiological conditions and that the licensee has established a means to inform workers of changes that could significantly impact their occupational dose; and
- severe radiation field dose gradients that can result in non-uniform exposures of the body.

The inspectors observed work in potential airborne areas and evaluated whether the air samples were representative of the breathing air zone. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and were representative of actual work areas. The inspectors evaluated the licensee’s program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

b. Findings

No findings of significance were identified.

.3 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors selected three containers holding non-exempt licensed radioactive materials that may cause unplanned or inadvertent exposure of workers, and assessed whether the containers were labeled and controlled in accordance with 10 CFR Part 20.1904, “Labeling Containers,” or met the requirements of 10 CFR Part 20.1905(g).

The inspectors reviewed the following three radiation work permits (RWPs) used to access high radiation areas (HRAs) and evaluated the specified work control instructions or control barriers.

- RWP 1100; Valve Work;
- RWP 1115; Reactor Head Set, Clean Flange, and Flush Cavity; and
- RWP 1116; Reactor Cavity Decontamination.

For these RWPs, the inspectors assessed whether allowable stay times or permissible dose (including from the intake of radioactive material) for radiologically significant work under each RWP were clearly identified. The inspectors evaluated whether electronic personal dosimeter (EPD) alarm set-points were in conformance with survey indications and licensee policy.

The inspectors reviewed selected occurrences where a worker's EPD noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and dose evaluations were conducted as appropriate.

For work activities that could suddenly and severely increase radiological conditions, the inspectors assessed the licensee's means to inform workers of changes that could significantly impact their occupational dose.

b. Findings

No findings of significance were identified.

.4 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitored potentially contaminated material leaving the radiological control areas; and inspected the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use and evaluated whether the work was performed in accordance with plant procedures and whether the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors assessed whether the radiation monitoring instrumentation had appropriate sensitivity for the type(s) of radiation present.

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicated the presence of licensed radioactive material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters. The inspectors assessed whether or not the licensee had established a de facto "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high-radiation background area.

The inspectors selected three sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact (i.e., they were not leaking their radioactive content).

The inspectors evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

b. Findings

No findings of significance were identified.

.5 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of EPDs in high noise areas as HRA monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee had properly employed an NRC-approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high-radiation work areas with significant dose rate gradients.

The inspectors reviewed the following three RWPs for work within airborne radioactivity areas with the potential for individual worker internal exposures.

- RWP 1100; Valve Work;
- RWP 1115; Reactor Head Set, Clean Flange, and Flush Cavity; and
- RWP 1116; Reactor Cavity Decontamination.

For these RWPs, the inspectors evaluated airborne radioactive controls and monitoring, including potentials for significant airborne levels (e.g., grinding, grit blasting, system breaches, entry into tanks, cubicles, and reactor cavities). The inspectors assessed barrier (e.g., tent or glove box) integrity and temporary high-efficiency particulate air ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within spent fuel and other storage pools. The inspectors assessed whether appropriate controls (i.e., administrative and physical controls) were in place to preclude inadvertent removal of these materials from the pool.

The inspectors examined the posting and physical controls for selected HRAs and very high radiation areas to verify conformance with the Occupational PI.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the radiological conditions in their workplace and the RWP controls/limits in place, and whether their performance reflected the level of radiological hazards present.

The inspectors reviewed several radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the radiation protection manager any problems with the corrective actions planned or taken.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors observed the performance of the radiation protection technicians with respect to all radiation protection work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace and the RWP controls/limits, and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed several radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

b. Findings

No findings of significance were identified.

.8 Problem Identification and Resolution (02.09)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring and exposure controls. The inspectors assessed the licensee's process for applying operating experience to their plant.

b. Findings

No findings of significance were identified.

2RS2 Occupational As-Low-As-Is-Reasonably-Achievable Planning and Controls (71124.02)

This inspection constituted a partial sample as defined in IP 71124.02-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed pertinent information regarding collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspectors reviewed the licensee's 3-year rolling average collective exposure.

The inspectors reviewed the site-specific trends in collective exposures (using NUREG-0713, "Occupational Radiation Exposure at Commercial Nuclear Power Reactors and Other Facilities," and plant historical data) and source term (average contact dose rate with reactor coolant piping).

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures as-low-as-is-reasonably-achievable (ALARA), which included a review of processes used to estimate and track exposures from specific work activities.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected the following three work activities of the highest exposure significance.

- 22 Steam Generator Secondary Side Maintenance;
- 22 Steam Generator Primary Side Maintenance; and
- Remove Primary Manways and Install Nozzle Dams.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined whether the licensee reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The inspectors assessed whether the licensee's planning identified appropriate dose mitigation features; considered alternate mitigation features; and defined reasonable dose goals. The inspectors evaluated whether the licensee's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices and/or heat stress mitigation equipment (e.g., ice vests). The inspectors determined whether the licensee's work planning considered the use of remote technologies (e.g., tele-dosimetry, remote visual monitoring, and robotics) as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspectors assessed the integration of ALARA requirements into work procedure and RWP documents.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in the licensee's ALARA planning for these work activities. The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements, and evaluated the accuracy of these time estimates. The inspectors assessed the reasons (e.g., failure to adequately plan the activity, failure to provide sufficient work controls) for any inconsistencies between intended and actual work activity doses.

The inspectors determined whether post-job reviews were conducted and if identified problems were entered into the licensee's CAP.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors reviewed the assumptions and basis (including dose rate and man-hour estimates) for the current annual collective exposure estimate for reasonable accuracy for select ALARA work packages. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and the intended dose outcome.

The inspectors evaluated whether the licensee had established measures to track, trend, and if necessary to reduce, occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates (intended dose) were based on sound radiation protection and ALARA principles or if they were just adjusted to account for failures to control the work. The inspectors evaluated whether the frequency of these adjustments called into question the adequacy of the original ALARA planning process.

b. Findings

No findings of significance were identified.

2RS4 Occupational Dose Assessment (71124.04)

This inspection constituted one sample as defined in IP 71124.04-5.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the results of radiation protection program audits related to internal and external dosimetry (e.g., licensee's quality assurance (QA) audits, self-assessments, or other independent audits) to gain insights into overall licensee performance in the area of dose assessment and focus the inspection activities consistent with the principle of "smart sampling."

The inspectors reviewed the most recent National Voluntary Laboratory Accreditation Program (NVLAP) accreditation report on the vendor's most recent results to determine the status of the contractor's accreditation.

A review was conducted of the licensee procedures associated with dosimetry operations, including issuance/use of external dosimetry (routine, multi-badging, extremity, neutron, etc.), assessment of internal dose (operation of whole body counter, assignment of dose based on derived air concentration ((DAC)-hours, urinalysis, etc.), and evaluation of and dose assessment for radiological incidents (distributed contamination, hot particles, loss of dosimetry, etc.).

The inspectors evaluated whether the licensee had established procedural requirements for determining when external and internal dosimetry is required.

b. Findings

No findings of significance were identified.

.2 External Dosimetry (02.02)

a. Inspection Scope

The inspectors evaluated whether the licensee's dosimetry vendor was NVLAP accredited and if the approved irradiation test categories for each type of personnel dosimeter used were consistent with the types and energies of the radiation present and the way the dosimeter was being used (e.g., to measure deep dose equivalent, shallow dose equivalent, or lens dose equivalent.)

The inspectors evaluated the onsite storage of dosimeters before their issuance, during use, and before processing/reading. The inspectors also reviewed the guidance provided to radiation workers with respect to care and storage of dosimeters.

The inspectors assessed the use of active dosimeters EPDs to determine if the licensee used a "correction factor" to address the response of the EPD as compared to Thermal Luminescence Dosimetry/Optically Stimulated Luminescence for situations when the EPD must be used to assign dose and whether the correction factor was based on sound technical principles.

The inspectors selected five dosimetry occurrence reports or CAP documents for adverse trends related to electronic dosimeters, such as interference from electromagnetic frequency, dropping or bumping, failure to hear alarms, etc. The inspectors assessed whether the licensee had identified any trends and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

.3 Internal Dosimetry (02.03)

Routine Bioassay (In Vivo)

a. Inspection Scope

The inspectors reviewed procedures used to assess the dose from internally deposited nuclides using whole body counting equipment. The inspectors evaluated whether the procedures addressed methods for differentiating between internal and external contamination, the release of contaminated individuals, the route of intake, and the assignment of dose.

The inspectors reviewed the whole body count process to determine if the frequency of measurements was consistent with the biological half-life of the nuclides available for intake.

The inspectors reviewed the licensee's evaluation for use of its portal radiation monitors as a passive monitoring system to determine if instrument minimum detectable activities were adequate to determine the potential for internally deposited radionuclides sufficient to prompt additional investigation.

The inspectors selected three whole body counts and evaluated whether the counting system used had sufficient counting time/low background to ensure appropriate sensitivity for the potential radionuclides of interest. The inspectors reviewed the radionuclide library used for the count system to determine its appropriateness. The inspectors evaluated whether any anomalous count peaks/nuclides indicated in each output spectra received appropriate disposition. The inspectors reviewed the licensee's 10 CFR Part 61 data analyses to determine that the nuclide libraries included appropriate gamma-emitting. The inspectors evaluated how the licensee accounted for hard-to-detect nuclides in the dose assessment.

b. Findings

No findings were identified.

Special Bioassay (In Vitro)

a. Inspection Scope

There were no internal dose assessments obtained using in vitro monitoring for the inspectors to review. The inspectors reviewed and assessed the adequacy of the licensee’s program for in vitro monitoring (i.e., urinalysis and fecal analysis) of radionuclides (tritium, fission products, and activation products).

b. Findings

No findings of significance were identified.

Internal Dose Assessment – Airborne Monitoring

a. Inspection Scope

The inspectors reviewed the licensee's program for airborne radioactivity assessment and dose assessment, as applicable, based on airborne monitoring and calculations of DAC. The inspectors determined whether flow rates and collection times for air sampling equipment were adequate to allow lower limit of detections to be obtained. The licensee had not performed dose assessments using airborne/DAC monitoring since the last inspection.

b. Findings

No findings of significance were identified.

Internal Dose Assessment – Whole Body Count Analyses

a. Inspection Scope

The inspectors reviewed several dose assessments performed by the licensee using the results of whole body count analyses. The inspectors determined whether affected personnel were properly monitored with calibrated equipment and that internal exposures were assessed consistent with the licensee's procedures.

b. Findings

No findings of significance were identified.

.4 Special Dosimetric Situations (02.04)

Declared Pregnant Workers

a. Inspection Scope

The inspectors assessed whether the licensee informed workers, as appropriate, of the risks of radiation exposure to the embryo/fetus, the regulatory aspects of declaring a pregnancy, and the specific process to be used for (voluntarily) declaring a pregnancy.

The inspectors selected two individuals who have declared pregnancy during the current assessment period and evaluated whether the licensee’s radiological monitoring program (internal and external) for declared pregnant workers was technically adequate to assess the dose to the embryo/fetus. The inspectors reviewed exposure results and monitoring controls employed by the licensee and with respect to the requirements of 10 CFR Part 20.

b. Findings

No findings of significance were identified.

Dosimeter Placement and Assessment of Effective Dose Equivalent for External Exposures

a. Inspection Scope

The inspectors reviewed the licensee's methodology for monitoring external dose in non-uniform radiation fields or where large dose gradients exist. The inspectors evaluated the licensee's criteria for determining when alternate monitoring, such as use of multi-badging, was to be implemented.

The inspectors reviewed dose assessments performed using multi-badging to evaluate whether the assessment was performed consistently with licensee procedures and dosimetric standards.

b. Findings

No findings of significance were identified.

Shallow Dose Equivalent

a. Inspection Scope

The inspectors evaluated the licensee’s method (e.g., VARSKIN or similar code) for calculating shallow dose equivalent from distributed skin contamination or discrete radioactive particles.

b. Findings

No findings of significance were identified.

Neutron Dose Assessment

a. Inspection Scope

The inspectors evaluated the licensee’s neutron dosimetry program, including dosimeter types and/or survey instrumentation.

The inspectors reviewed one neutron exposure situation (e.g., at-power containment entries) and assessed whether: (a) dosimetry and/or instrumentation was appropriate for the expected neutron spectra; (b) there is sufficient sensitivity for low dose and/or dose rate measurement; and (c) neutron dosimetry was properly calibrated. The inspectors also assessed whether interference by gamma radiation had been accounted for in the calibration and whether time and motion evaluations were representative of actual neutron exposure events, as applicable.

b. Findings

No findings of significance were identified.

Assigning Dose of Record

a. Inspection Scope

For the special dosimetric situations reviewed in this section, the inspectors assessed how the licensee assigned dose of record for total effective dose equivalent, shallow dose equivalent, and lens dose equivalent. This elevation included an assessment of external and internal monitoring results, supplementary information on Individual exposures (e.g., radiation incident investigation reports and skin contamination reports), and radiation surveys and/or air monitoring results when dosimetry was based on these techniques.

b. Findings

No findings of significance were identified.

.5 Problem Identification and Resolution (02.05)

a. Inspection Scope

The inspectors assessed whether problems associated with occupational dose assessment are being identified by the licensee at an appropriate threshold and are properly addressed for resolution in the licensee CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving occupational dose assessment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for both units for the period from the third quarter of 2009 through the second quarter of 2010. 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, and NUREG-1022, “Event Reporting Guidelines 10 CFR 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 work orders, CAPs, 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 failures samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency Alternating Current (AC) Power System performance indicator for both units for the period from the third quarter of 2009 through the second quarter of 2010. 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, MSPI derivation reports, CAPs, 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 issue report 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 of significance were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - High Pressure Injection Systems PI both units for the period from the third quarter of 2009 through the second quarter of 2010. 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, CAPs, MSPI derivation 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 none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Heat Removal System PI both units for the period from the third quarter of 2009 through the second quarter of 2010. 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, CAPs, event reports, MSPI derivation 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 none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.5 Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual (RETS/ODCM) Radiological Effluent Occurrences performance indicator for the period of August 2009 through July 2010. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6 to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's corrective action database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates between August 2009 and July 2010 to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose.

This inspection constituted one RETS/ODCM radiological effluent occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.6 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the Reactor Coolant System (RCS) Specific Activity PI for Prairie Island Station Units 1 and 2 for the period from the second quarter 2009 through the second quarter 2010. 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, were used. The inspectors reviewed the licensee's RCS chemistry samples, TS requirements, CAPs, event reports and NRC Integrated Inspection Reports for the period of second quarter 2009 through the second quarter 2010, 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. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two reactor coolant system specific activity samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.7 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences PI for the period from the second quarter 2009 through the second quarter 2010. 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, were used. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope, and breadth of its data review, and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational radiological occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance 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 of significance 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 CAP 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 of significance were identified.

.3 Selected Issue Follow-Up Inspection: Review of Actions Taken in Response to Substantive Cross-Cutting Issue

a. Inspection Scope

During the 2009 mid-cycle plant performance assessment, the NRC identified a substantive cross-cutting issue (SCCI) in the area of human performance. Inspection Manual Chapter 0305, "Operating Reactor Assessment Program," defined an SCCI as a cross- cutting theme identified in problem identification and resolution, human performance or safety conscious work environment about which the NRC staff has a concern with the licensee's scope of efforts or progress in addressing the cross-cutting theme. Based upon inspection findings identified between July 2008 and June 2009, the NRC concluded that the SCCI contained specific human performance cross-cutting themes in the following areas:

- Systematic Process;
- Conservative Assumptions;
- Procedure Adequacy; and
- Procedure Compliance.

The NRC formally reviewed the licensee's progress in addressing this SCCI during internal performance review meetings held every 6 months. However, the resident inspectors focused on the licensee's performance improvement initiatives daily. The resident inspectors performed specific baseline inspection samples to assess the licensee's progress in improving performance.

In preparation for the 2010 mid-cycle plant performance assessment meeting, the inspectors performed an in-depth review of SCCI related corrective actions contained within the licensee's excellence plan. The inspectors met with licensee individuals involved in implementing and monitoring excellence plan activities, reviewed corrective action documents to ensure that the proposed/recommended corrective actions were appropriately reflected in the excellence plan, reviewed available assessments and/or effectiveness reviews, reviewed cross-cutting aspects of inspection issues documented during the performance assessment period, and completed multiple inspection samples (with specific focus on the SCCI themes) to assess whether the licensee's corrective actions had resulted in a positive, sustainable improvement in the specific theme.

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

b. Observations and Findings

The inspectors determined that the number of findings identified in each of the SCCI themes had declined during the current assessment period (July 2009 through June 2010). However, the number of findings in three of the four themes remained high. Specifically, the NRC documented at least three inspection findings in three of the four SCCI themes. While the decline in the overall number of findings in each theme demonstrated improved performance, the inspectors concluded that positive, sustainable improvement had not been achieved in three of the four areas due to the number of NRC inspection issues and the following:

- The licensee's corrective action effectiveness had not been evaluated;
- The use of processes was not always embraced during the performance of plant activities;
- Procedure use remained a factor in several inspection issues; and
- The backlog of temporary and permanent procedure change requests remained high indicating that procedure adequacy required additional improvement.

The NRC concluded in a letter to the licensee dated September 1, 2010, that positive, sustainable improvement had been noted in the human performance – conservative assumption area such that this SCCI theme was closed. Specifically, the licensee established and implemented an operational decision making process which increased the breadth and depth of information considered by management prior to making decisions that potentially impacted plant operations and risk.

No findings of significance were identified.

.4 Selected Issue Follow-Up Inspection: Corrective Action Program 1240435; Loss of Letdown and Pressurizer Heaters Due to Bistable Failures

a. Inspection Scope

On July 6, 2010, Unit 2 experienced a loss of normal letdown and the inability to operate the pressurizer heaters from the control room due to a failed bistable. In response to the event, operations personnel entered Procedure 2C12.1 AOP3, "Loss of Letdown," to place excess letdown in service. In addition, a non-licensed operator was dispatched to the hot shutdown panel to energize the Group A and B pressurizer heaters locally. The inspectors reviewed the event and the control of non-licensed operators dispatched to the hot shutdown panel due to the effect of their action on reactivity.

The inspectors recognized the similarity of using non-licensed operators to perform actions normally completed by a licensed operator to an event documented in NRC Information Notice 2010-06, dated February 17, 2010. As a result, the inspectors reviewed licensee actions taken in response to the bistable failure and the licensee's evaluation of Information Notice 2010-06.

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

b. Observations and Findings

The licensee initiated CAP 1240435 to document the loss of letdown and pressurizer heaters due to the bistable failure. The licensee determined the cause of the loss of letdown and pressurizer heaters was an age related failure of Foxboro bistable 2LC-428D. This failed bistable caused the letdown valves to isolate and the pressurizer heaters to de-energize as designed. The licensee replaced, tested, and returned the bistable to service under WO 408208. Long term actions were already underway to resolve aging and obsolescence issues with Foxboro modules. Consequently, the licensee determined no further long term actions were necessary as part of CAP 1240435.

On April 20, 2010, the licensee initiated CAP 1228173 to evaluate NRC Information Notice 2010-06. The licensee's evaluation concluded that the operating experience included in the information notice was not applicable to Prairie Island since it concerned a boiling water reactor control rod drive system. The inspectors determined this evaluation was weak and did not address the potential for non-licensed operators to manipulate equipment with the potential to affect reactivity without the knowledge and consent of a licensed operator at the controls as required by 10 CFR Part 50.54(j). This weakness was discussed with the licensee and corrective action 1253367 was generated to track the issue to resolution.

Although the licensee's evaluation of the Information Notice was weak, the inspector reviewed procedural requirements for the control of reactivity established in SWI-O-50, "Reactivity Management," and FP-OP-COO-01, "Conduct of Operations." Since the specific control of non-licensed operators was discussed in these procedures, the inspectors determined that the licensee had established adequate requirements to address the control of non-licensed operators as discussed in the Information Notice.

Subsequent to the event, the inspectors reviewed the licensee's implementation of these procedural requirements to ensure appropriate control of non-licensed operators during potential reactivity manipulations was adequate. The inspectors determined that the non-licensed operators were pre-briefed on their actions, utilized a procedure for energizing the pressurizer heaters at the hot shutdown panel, and maintained constant communication with a reactor operator in the control room. The inspectors concluded that the licensee implemented adequate non-licensed operator controls regarding this potential reactivity manipulation event.

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

.1 Unit 2 Containment Sample Valve Mispositioned

a. Inspection Scope

The inspectors interviewed radiation protection and operations personnel to determine the sequence of events that led to a valve being mispositioned following the performance of Procedure RPIP 1221, "Containment In-Line Air Sampling," on September 7, 2010. The inspectors reviewed Procedure RPIP 1221 and procedure use and adherence requirements as part of this inspection. The inspectors also reviewed the licensee's human performance event investigation which determined that the Radiation Protection Specialist became distracted by a request from another department which resulted in the valve being mispositioned. Documents reviewed in this inspection are listed in the Attachment.

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

b. Findings

The enforcement aspects of this issue are documented in Section 4OA7 of this inspection report.

.2 (Closed) Licensee Event Report 05000306/2010-002-00: Unit 2 Turbine Shutdown Due to the Loss of a Main Feedwater Pump That Resulted in a Reactor Trip

On May 25, 2010, Prairie Island Unit 2 experienced an automatic reactor trip from approximately 32 percent power due to a turbine trip. The turbine trip occurred due to an unplanned shutdown of the operating main feedwater pump. This event was initially discussed in Section 4OA3.9 of NRC Inspection Report 05000282/2010003; 05000306/2010003. The inspectors opened a URI to ensure that the licensee's corrective action evaluation was reviewed upon completion to identify any performance deficiencies.

The inspectors reviewed the licensee's apparent cause evaluation and determined that the main feedwater pump tripped due to a pressure switch failure. The switch was subsequently replaced. The licensee determined that the pressure switch failure occurred because no activity existed to ensure that the switch was replaced on a periodic basis. The inspectors reviewed the calibration trending history for the switch and other similar switches within the plant. Based upon this review, the inspectors concluded that trending data would not have resulted in the licensee taking additional data to replace these switches. As a result, no performance deficiency existed because the failure of the switch was not within the licensee's ability to foresee or detect. The licensee's corrective action to prevent recurrence consisted of implementing a new preventive maintenance activity to replace the pressure switch (and the eleven other switches) on a periodic basis. The inspectors concluded that the periodic replacement should prevent future age related switch failures. Documents reviewed as part of this inspection are listed in the attachment. The licensee event report (LER) was reviewed by the inspectors and no findings of significance were identified and no violation of NRC requirements occurred. This LER is closed.

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

.3 (Closed) Licensee Event Report 05000282/2009-004-00; 05000306/2009-004-00: Residual Heat Removal System Inoperability While in Mode 4 Due to Potential Steam Voiding

a. Inspection Scope

While determining the scoping to comply with the requirements of NRC GL 2008-01, the licensee identified that high temperature water within the residual heat removal (RHR) system had the potential to flash to steam if a loss of coolant accident (LOCA) were to occur during Mode 4 reactor operations. Under these conditions, a void could have formed and traveled into the common suction for the RHR pumps. Had it occurred, this condition would have prevented the RHR system from performing its safety function.

The inspectors reviewed the licensee's corrective action documents and the implementation of corrective actions to needed to address the LER condition. This inspection was completed through an in-office review of documents and discussions with engineering personnel. This LER is closed.

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

b. Findings

Introduction: A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to ensure that measures were established to assure that applicable regulatory requirements and the design basis for the RHR system were correctly translated into specifications, drawings, procedures and instructions. Specifically, the licensee failed to have appropriate procedures in place to ensure that the safety function of the RHR system was maintained following RHR valve repositioning to support transitioning from the decay heat removal mode of RHR to providing suction from the refueling water storage tank (RWST) or following a Mode 4 LOCA.

Description: On December 16, 2008, engineering personnel performed ultrasonic testing of RHR system piping determined to be susceptible to voiding as part of GL 2008-01. The results of this testing showed the presence of a void on the common line from the Unit 1 reactor coolant system hot leg piping to both of the RHR pump suctions. An initial engineering analysis determined that the operability of the RHR system was not impacted by this void.

In March 2009 the licensee revisited the initial engineering analysis and operating experience from another nuclear plant. During this review, engineering personnel concluded that the RHR system piping in both units would be vulnerable to void formation under certain plant conditions. Specifically, high temperature water in the RHR system had the potential to flash to steam during heatup or cooldown operations. During these operating modes, operations personnel placed the RHR system in the decay heat removal (DHR) mode of operation and, thus, fluid in the RHR system piping would be at RCS temperature and pressure. If needed, valves would be repositioned, such as the suction valve from the RWST, to allow cool water to be injected into the reactor coolant system and cool the reactor. This mode of RHR operation is referred to as the emergency core cooling system (ECCS) mode of operation.

By design, the RWST was vented to the auxiliary building atmosphere. The licensee was concerned that repositioning of the RHR suction valve to the RWST following a LOCA would lead to flash evaporation of the water in the RHR system because the temperature and the pressure of the RHR fluid exceeded the saturation conditions within the RWST. The licensee performed a calculation to determine the maximum allowable RHR temperature to preclude void formation during the repositioning of the valves. This calculation considered the static head of and ambient pressure on the RWST and the maximum temperature allowable at the RHR hot leg suction. The licensee calculated a maximum allowable RHR temperature of 231 degrees Fahrenheit. The licensee reviewed previous Mode 3 and Mode 4 temperature data and determined that the RHR system had not been protected from the potential steam voiding condition during some previous outages. This was documented in the above LER. The licensee also implemented compensatory measures and procedure changes such that one train of

RHR was protected for ECCS operation while the other train was used for DHR when reactor coolant temperatures were above 226 degrees Fahrenheit. Actual RCS temperatures could be up to 231 degrees Fahrenheit when the indicated temperature was 226 degrees Fahrenheit due to uncertainties. The LER did not address the potential void formation in Mode 3 because the licensee determined that the RHR system was sufficiently cool before entering Mode 3 within the previous 3 years. Therefore, RHR was confirmed to be operable while in Mode 3 for both Units.

During a review of this LER, the inspectors identified that the temperature specified in the licensee's compensatory measures was not low enough to ensure that the RHR system would be protected from voiding if a large LOCA occurred during Mode 4 operations. The inspectors were concerned that this condition could lead to steam/air binding the RHR pumps and/or an adverse water hammer following system realignment to the RWST.

Inspector Review of the Licensee Event Report

The inspectors noted, however, that both RHR systems would experience steam void formation at temperatures below 231 degrees Fahrenheit if a LOCA occurred that was of sufficient size to depressurize the RCS. Specifically, the RHR system was subjected to RCS temperatures and pressures when operated in the DHR mode, which exceeded the saturation conditions of water at atmospheric pressure. During a shutdown large-LOCA the reactor could depressurize to atmospheric conditions. This would result in the flash evaporation of water inside the RHR system because its temperature would be above the saturation temperature of water at atmospheric pressure. In addition, the static head provided by the difference in height between the reactor coolant system hot leg and the RHR pump inlet could not be credited because the water volume at this location will experience flash evaporation if the temperature at the hot leg is above its saturation temperature. Consequently, the volume of water below it will not benefit from the resulting static head (i.e. there will be a reduction of the height of the column of water above it). As a result, this volume of water would flash if its temperature is above saturation temperatures. This effect would repeat itself all the way down to the lowest elevations. Therefore, the system would be voided before its suction is swapped over to the RWST.

Although the energy of the water volume was not enough to evaporate the entire volume, flashing would occur at all locations above saturation conditions. Also, the resulting volume of the steam would be significantly greater than the water volume that existed before the flash evaporation. Specifically, a simplified thermodynamic analysis that assumed initial and final saturation conditions at 231 degrees Fahrenheit and 212 degrees Fahrenheit, respectively, determined that only approximately 1.6 percent of the mass of water would evaporate. However, the resulting steam volume would be 25.4 times greater than the initial volume of water (i.e. at 231 degrees Fahrenheit) and 25.7 times greater than the final volume of water (i.e. the fraction of water that did not evaporate). Therefore, the resulting steam volume would move to other locations, including the hot leg, possibly by displacing water volumes and further decreasing the available head. Based on this analysis, the inspectors concluded that the licensee's procedures did not adequately protect the RHR system from failure due to voiding/loss of suction if a large LOCA occurred in Mode 4.

Prairie Island TS 3.5.3, “ECCS – Shutdown,” requires one train of ECCS be operable during Mode 4 operations. This requirement ensured that sufficient ECCS flow was available to the reactor core following a shutdown LOCA. However, TS 3.5.3 was modified by a note that allowed an RHR train to be considered operable for ECCS operation while operating in the DHR mode if the train was capable of being manually realigned to the ECCS mode of operation and not otherwise inoperable. Prior to March 2009, the licensee placed both trains of RHR into service in the DHR mode to shorten the cooldown time as allowed by TS.

In addition, Westinghouse completed an industry evaluation concerning the potential for water to flash to steam in the RHR pump suction line in 1993. Westinghouse Nuclear Safety Advisory Letter (NSAL) 93-004 recommended that plant operating procedures be reviewed to verify that the potential for forming steam voids was precluded. One option presented was to force cool the piping. Since Prairie Island procedures used forced cooling, the licensee concluded that the guidance had been met. However, it appears that the individuals that prepared and reviewed the response to the NSAL failed to recognize that the forced cooling line returned too close to the RHR pump suction to effectively cool all of the RHR suction piping. Additionally, NSAL-93-004 did not provide recommendations for protecting one train of RHR for emergency core cooling system function during Mode 4 operations.

The licensee captured the inspectors concerns in their CAP as CAP 1180912 and CAP 1242456. The licensee implemented a compensatory measure to procedurally restrict the use of RHR in Mode 4 such that one train was protected for ECCS at all times that it was required by TS 3.5.3 and to manage RHR void formation.

Analysis: The inspectors determined that the licensee’s failure to have appropriate procedures in place to ensure that the safety function of the RHR system was maintained following a Mode 4 LOCA was a performance deficiency that required a significance determination process evaluation.

The performance deficiency was determined to be more than minor because it was associated with the mitigating system cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee’s procedures and the design of the RHR system did not ensure the capability of the system to perform its safety function during Mode 4 operations.

Risk Evaluation for Voiding Introduced During Residual Heat Removal Valve Repositioning to the Refueling Water Storage Tank

The senior reactor analyst determined that a phase 2 evaluation was required because the potential void formation could impact core cooling equipment, including RHR injection capability from the RWST and RHR recirculation capability from the containment sump. Using IMC 0609, Appendix G, “Shutdown Significance Determination Process (SDP),” this finding was determined to degrade the licensee’s ability to add RCS inventory, which required a phase 2 SDP analysis.

The senior reactor analyst determined that the applicable phase 2 SDP worksheet was Worksheet 5 – SDP for a Pressurized Water Reactor Plant – Loss of Inventory in Plant Operating State 1 (RCS closed). The maximum total amount of time of RHR inoperability for either unit over the past 3 year period reviewed by the licensee was approximately 78 hours. A review of the data showed a maximum time of inoperability in any single 12 month period to be approximately 44 hours. Therefore, an exposure period of less than 3 days was used in the SDP phase 2 evaluation.

For the phase 2 evaluation, the initiating event likelihood was “4” based on the exposure period and Table 5 of Appendix G. No mitigation credit was given for RHR system recovery based on the assumption that the pumps would be unrecoverable after the introduction of the void from the pump suction line. The mitigation credit for RCS injection was reduced to “2” to represent credit for a single train of safety injection that would be manually initiated in response to a loss of inventory event. The mitigation credit for steam generator cooling was also reduced to “2” to represent the possibility that only one auxiliary feedwater pump may have been available to feed the steam generators during the exposure period. The result of the phase 2 evaluation was three core damage sequences of “8,” which by the counting rule is equivalent to a sequence of “7.” This represented a change in core damage frequency of less than 1.0E-6, which is a finding of very low safety significance (Green).

<u>Risk Evaluation for Voiding Caused by Large Loss Of Coolant Accident in Mode 4</u>

The senior reactor analyst determined that this portion of the finding did not meet any of the criteria in Checklist 2 “PWR Cold Shutdown Operation: Reactor Coolant System Closed and Steam Generators Available for DHR Removal” of IMC 0609 “Shutdown Operations Significance Determination Process” for requiring a phase 2 or 3 analysis because the condition only affected the RHR ECCS injection function in response to a postulated large LOCA during shutdown, an initiating event that is very unlikely to occur and not modeled in Appendix G. Therefore, this finding screened as very low safety significance (Green) in phase 1.

This finding had no cross-cutting aspect since there was no performance characteristic from IMC 0310 that was a significant contributor to the performance deficiency.

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Technical Specification 3.5.3, “ECCS – Shutdown,” required one train of ECCS be operable during Mode 4 operations.

Contrary to the above, as of July 12, 2010, the licensee had not correctly translated applicable regulatory requirements and the design basis into specifications and procedures. Specifically, the operability requirements of RHR in Mode 4 defined by TS were not translated into applicable procedures or specifications of the system to ensure that the RHR system was protected from a loss of safety function during Mode 4 operations. Because this violation was of very low safety significance and it was entered into the licensee’s CAP as CAP 1180912 and CAP 1242456, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010004-02; 05000301/2010004-02, Failure to Ensure That RHR Would Be Capable to Respond During Mode 4 Events). Corrective actions for this issue including revising procedures to ensure that the at least one train of the RHR system was protected for ECCS functions during operations in Modes 3 or 4.

.4 <u>(Closed) Licensee Event Report 05000306/2010-003-00: Unit 2 Fuel Oil Transfer Pumps Are Vulnerable to a Potential Common Mode Failure</u>

On May 12, 2010, the licensee initiated CAP 1232408 when they discovered that the control power for each set of the Unit 2 emergency diesel generator (EDG) fuel oil transfer pumps came from the same direct current power panel breaker. The same day, CAP 1232504 was also written to document that power to each set of fuel oil transfer pumps came from the same 480 Volt breaker. The inspectors reviewed the corrective action documents and evaluations associated with this issue. The inspectors also discussed this issue with engineering, operations and maintenance personnel. Based upon the results of this review, the inspectors determined that the design of the Unit 2 EDG fuel oil transfer system was not adequate to ensure that sufficient onsite oil storage was provided to operate the required number of EDGs for 7 days or the time required to replenish the oil sources outside the plant site following any limiting design basis event or accident as required by licensing basis and Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators, Revision 1, October 1979," and therefore, the issue was a performance deficiency. The licensee performed a calculation and determined that each pair of fuel oil storage tanks needed to contain at least 39,000 gallons of fuel oil to ensure that the respective EDG remained operable per the TSs. A review of fuel oil storage tank inventory from May 2007 through May 2010 revealed that fuel oil storage requirements for the D5 EDG were below 39,000 gallons for one day. A similar review of the D6 fuel oil storage tank inventory showed that the inventory was below 39,000 gallons for 62 days. The safety significance and enforcement aspects of this violation are discussed in Section 4OA7 of this Inspection Report. Corrective actions for this issue included transferring fuel oil to each tank to ensure that each EDG would have at least 39,000 gallons of fuel oil, revising the control room daily logs to ensure that the revised fuel oil volumes were checked and maintained, and initiating an engineering change request to correct the common mode failure. This LER is closed.

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

.5 <u>Retraction of Event Notification 45937: Both Trains of Residual Heat Removal Inoperable</u>

a. <u>Inspection Scope</u>

On May 19, 2010, with Unit 2 operating in Mode 4, the licensee informed the NRC that both trains of the Unit 2 RHR system were inoperable. Specifically, at 12:28 p.m., the licensee declared both RHR trains inoperable when the system did not meet inservice testing requirements in a TS surveillance test. The licensee conducted troubleshooting activities which required that opening the RHR pit covers. During the troubleshooting activities, the licensee identified that a new procedure revision had resulted in changing the differential pressure conditions that existed during the test. This change had the potential to result in a surveillance test failure even though an equipment failure had not occurred. The licensee revised the test procedure to reflect the differential pressure conditions that had existed during previous refueling outages and successfully re-performed the test. No equipment deficiencies were identified. The RHR system met all inservice testing requirements during the test reperformance. However, the licensee identified that opening the pit covers also resulted in RHR system inoperability since the covers were not allowed to be open while the reactor was operating in Modes 1 through 4.

On July 16, 2010, the licensee retracted Event Notification 45937 based upon information which showed that the opening of the pit covers would not have impacted the ability of the RHR system to perform its safety function. The inspectors reviewed licensee procedures for the residual heat removal system, design information and previous evaluations to determine whether the licensee's retraction of Event Notification 45937 was appropriate. The inspectors determined a violation still existed as discussed in paragraph b below, because inadequate procedures caused issues during testing of the RHR system.

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

b. Findings

A licensee identified violation of 10 CFR Part 50, Appendix B, Criterion V, was documented in Section 4OA7 of NRC Integrated Inspection Report 05000282/2010003; 05000306/2010003.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000306/2010003-03: Review Licensee's Evaluation to Determine Whether Performance Deficiency Existed

a. Inspection Scope

The inspectors reviewed the licensee's apparent cause evaluation report for a Unit 2 reactor trip that occurred on May 25, 2010, to determine whether a performance deficiency had caused the reactor trip. The inspectors reviewed licensee procedures, training requirements, vendor technical manuals, instrument trending history, operating experience information, outage scope change forms, and discussed this event with maintenance, operations, and outage department personnel.

b. Findings

No findings of significance were identified.

.2 (Open) Temporary Instruction 2515/177: Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems (NRC Generic Letter 2008-01)

As documented in Sections 1R15, 1R22, and 4OA3 of this report, the inspectors confirmed the acceptability of the licensee's described actions. This inspection effort counts towards the completion of TI 2515/177 which will be closed in a later IR.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 7, 2010, the inspectors presented the inspection results to Mr. Mark Schimmel, Site Vice-President, and other members of the licensee staff. The licensee acknowledged the issues presented. A follow up exit to discuss the NRC identified NCV was conducted with Mr. B. Sawatzke on November 2, 2010 by J. Giessner. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- On August 6, 2010, the inspectors presented the radiation protection inspection results to Mr. Kevin Ryan, Plant Manager.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and were violations of NRC requirements which met the criteria of Section 2.3.2 of the NRC Enforcement Policy for being dispositioned as NCVs.

- Criterion III to 10 CFR Part 50, Appendix B, requires that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures and instructions. Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of structures, systems and components. The D5 and D6 EDG fuel oil system was designed to meet the requirements of Regulatory Guide 1.137. Regulatory Guide 1.137, Revision 1, October 1979, endorsed the requirements of ANSI N195-1976. Document ANSI N195-1976 required that sufficient onsite oil storage shall be provided to operate the required number of diesel generators for seven days or the time required to replenish the oil for sources outside the plant site following any limiting design basis event or accident. Contrary to the above, on May 12, 2010, the licensee identified that the design of the D5 and D6 EDG fuel oil system failed to meet the requirements of ANSI N195-1976, Regulatory Guide 1.137, and 10 CFR Part 50, Appendix B, Criterion III, “Design Control.” Specifically, the fuel oil system design was such that onsite oil storage was not provided to operate the required number of diesel generators for seven days or the time required to replenish the oil for sources outside the plant site following any limiting design basis event or accident. Corrective actions for this issue included adding oil to the respective fuel oil tanks to ensure that the onsite fuel oil storage was adequate to operate each EDG for 7 days, revising procedures to ensure that the fuel oil volumes remained adequate to meet the 7 day requirement, and initiating an engineering change request to correct the design issue.

  The inspectors determined that the failure to design the Unit 2 fuel oil storage system as required was a performance deficiency that required an SDP evaluation. The inspectors performed a Phase 1 SDP evaluation in accordance with IMC 0609 and determined that a Phase 2 evaluation was needed because the performance deficiency represented a condition that could cause a loss of system safety function. The inspectors performed a Phase 2 evaluation using the column associated with loss of a fuel oil transfer pump and assuming an exposure time of greater than 30 days. The results of this analysis showed that a Phase 3 evaluation was required due to the presence of white and yellow sequences. A Region III Senior Reactor Analyst performed a Phase 3 SDP evaluation and determined that this issue was of very low safety significance because the volume of fuel oil within the fuel oil system was adequate to support the mission time specified in the licensee's probabilistic risk assessment.

- Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

  Section 1.d of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires that written procedures be established, implemented and maintained regarding procedure adherence.

  Procedure FP-G-DOC-03, "Procedure Use and Adherence," was the licensee's procedure used to implement the requirements of Regulatory Guide 1.33, Section 1.d and TS 5.4.1.

  Step 5.4.1 of Procedure FP-G-DOC-03 stated that a procedure's requirements shall be adhered to during the course of activities, whether the procedure is in hand, available at the work site, or the activity is being performed from memory.

  Contrary to the above, on September 7, 2010, radiation protection personnel failed to adhere to the requirements specified in Procedure RPIP 1221, "Containment In-Line Air Sampling." Specifically, radiation protection personnel failed to properly complete Step 7.23 of RPIP 1221 which directed that valve 2RD-5-1 be shut.

  The inspectors determined that the failure to properly adhere to procedural requirements specified in RPIP 1221 was a performance deficiency that required an SDP evaluation. The inspectors performed a Phase 1 SDP evaluation in accordance with IMC 0609 and determined that this issue was of very low safety significance because the finding did not constitute a degradation of the radiological barrier for the control room, auxiliary building or spent fuel pool, did not represent a degradation of the barrier to protect the control room from a toxic atmosphere, did not represent an actual open pathway in the physical integrity of the reactor containment and did not involve an actual reduction in function of the hydrogen igniters. The licensee initiated CAP 1248806 to document this issue. Corrective actions for this issue included re-enforcing the procedure use and adherence requirements and human performance fundamentals.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Schimmel, Site Vice President
B. Sawatzke, Director Site Operations
K. Davison, Plant Manager
T. Roddey, Site Engineering Director
J. Anderson, Regulatory Affairs Manager
B. Boyer, Radiation Protection Manager
M. Davis, Compliance Engineer
C. England, Radiation Protection Manager
J. Lash, Nuclear Oversight Manager
R. Madjerich, Production Planning Manager
M. Milly, Maintenance Manager
J. Muth, Operations Manager
S. Northard, Performance Improvement Manager
D. Peterson, Fatigue Administrator
A. Pullam, Training Manager

Nuclear Regulatory Commission

J. Cameron, Chief, Reactor Projects Branch 6
J. Giessner, Chief, Reactor Projects Branch 4
M. Keefe, Health Physics and Human Performance Branch – Division of Inspection and Regional Support
R. Orlikowski, Acting Chief, Reactor Projects Branch 4
T. Wengert, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000282/2010004-01; 05000306/2010004-01	URI	Review Licensee's Evaluation of 122 Control Room Chiller Issue to Determine Whether Performance Deficiency Exists (Section 1R04)
05000282/2010004-02; 05000306/2010004-02	NCV	Failure to Ensure That RHR Would Be Capable to Respond During Mode 4 Events (Section 4OA3.3)

Closed

05000282/2009-004-00; 05000306/2009-004-00	LER	Residual Heat Removal System Inoperability While in Mode 4 Due to Potential Steam Voiding
05000306/2010-002-00	LER	Unit 2 Turbine Shutdown Due to the Loss of a Main Feedwater Pump That Resulted in a Reactor Trip
05000306/2010-003-00	LER	Unit 2 Fuel Oil Transfer Pumps Are Vulnerable to a Potential Common Mode Failure

05000306/2010003-03	URI	Review Licensee's Evaluation to Determine Whether Performance Deficiency Existed
05000282/2010004-02; 05000306/2010004-02	NCV	Failure to Ensure That RHR Would Be Capable to Respond During Mode 4 Events (Section 4OA3.3)

Discussed

2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

- Abnormal Procedure AB-2; Tornado/Severe Thunderstorm/High Winds; Revision 35
- SP 1039; Tornado Site Hazard Inspection; Revision 14
- USAR Section 2.3; Meteorology

1R04 Equipment Alignment

- 2C37.10-1; D5/D6 Diesel Generator Building Heating, Ventilation and Air Conditioning; Revision 5
- C37.11-1; Chilled Water Safeguards System; Revision 19
- CAP 1247908; Unable to Perform Work on 111 Switchgear Unit Cooler; August 31, 2010
- CAP 1247908; Human Performance Event Review Board; September 9, 2010
- Department Clock Reset, August 31, 2010 Event

1R05 Fire Protection

- Fire Hazards Analysis
- Safe Shutdown Analysis
- Procedure F5, Appendix A; Fire Zone Plans and Maps; Various Revisions

1R06 Flood Protection

- H43; Cable Condition Monitoring Program; Revision 3
- CAP 1150075; Site Has Not Fully Implemented Response to NRC GL 2007-01; September 10, 2008

1R11 Licensed Operator Requalification

- Vendor Manual; XH-505-28; Rev. 6
- Maintenance Rule Bases Document; Containment Vent
- Maintenance Rule A(1) Action Plan; Containment Ventilation System; April 20, 2010
- MRE 01209941; CD-34079 Stuck in GAP Position
- Health and Status Report; Containment Vent; September 9, 2010
- ACE 01209941; WO 395570; January 11, 2010

1R12 Maintenance Effectiveness

- CAP 1162357; CV-39409 Exhibited Dual Light Indication During SP 1245B; December 12, 2008

- CAP 1217510; Containment and Auxiliary Building Cooling Exceeds Design Pressure; February 9, 2010
- CAP 1151770; Containment Fan Coil Unit Valves Failed to Perform Safety Injection Function During SP-2083; September 23, 2008
- CAP 1226551; Unplanned Limiting Condition for Operation Entry for 22 and 24 Containment Fan Coil Units Inoperable; April 9, 2010
- CAP 1232173; CV-39415 Stem Separated from Plug Found During Overhaul; May 11, 2010
- CAP 1233092; Unit 2 Train B Chilled Water Supply and Return Valves Failed to Close; May 17, 2010
- CAP 1245191; Generate and a(1) Action Plan in accordance with H24 Section 5.7.4; August 11, 2010
- CAP 1245417; CV-39401 Unit 1 Train A Fan Coil Unit Cooling Water Supply Dual Indication; August 13, 2010
- Procedure H24; Maintenance Rule Program; Revision 17
- Prairie Island Maintenance Rule Bases Document
- Containment and Auxiliary Building Cooling Health and Status Report; September 14, 2010

1R13 Maintenance Risk Assessment and Emergent Work

- Unit 1 and Unit 2 Risk Assessment for August 8/9, 2010 for 121 MDCLP Replacement
- Unit 2 Risk Assessment for August 13, 2010 for Yellow Channel Tave Bistable Failure

1R15 Operability Evaluations

- OPR 1237113; Door 224 and Door 225 Sweeps Function Intermittently; June 11, 2010
- CAP 1237113; Door 224 and Door 225 Sweeps Function Intermittently; June 11, 2010
- CAP 1219652; Capture New Design Basis for Turbine Building High Energy Line Break Induced Internal Flooding; February 23, 2010
- 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 6
- OPR 1241732; Gas Void Found in Unit 1 SI/RHR Piping; July 17, 2010
- CAP 1241732; Gas Void Found in Unit 1 SI/RHR Piping; July 16, 2010
- NRC Regulatory Issue Summary 2008-14; Use of Tormis Computer Code for Assessment of Tornado Missile Protection; June 16, 2008
- NRC Inspection Manual Part 9900; Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety; April 16, 2008
- GEN-PI-005; Tornado and Seismic Evaluation of D1 and D2 Components; May 31, 1994
- GEN-PI- 002; Probabilistic Risk Assessment of D1 Emergency Diesel Generator Room Door Vulnerability to Tornado Missiles; May 4, 1993
- PM 3002-2-12; 12 DDCLP Diesel Minor Periodic Maintenance; Revision 35
- Work Plan 351761; Preventive Maintenance Work Plan Oil and Filter Change on Diesel Engine; August 19, 2010
- CAP 1249629; Preventive Maintenance Deferral PMRQ 7656-08 Due to MSPI Margin Issues On Cooling water; September 14, 2010
- Kettering to Schimmel Letter; Support Cooling Water MSPI Margin; June 11, 2010
- WO 401903; PMRQ 7656-08: 12 Diesel-Driven Cooling Water Pump Bleed/Feed Oil; September 11, 2010
- XH-48-63; Diesel Cooling Water Pump Engine; Revision 14
- CAP 1246406; Unit 1 and Unit 2 AFWP Design Flow Margin Reduced; August 20, 2010
- OPR 1246406; Unit 1 and Unit 2 AFWP Design Flow Margin Reduced; Revision 1

1R19 Post Maintenance Testing

- WO 362620; Perform Bus 16 Load Sequencer Return to Service; January 25, 2010
- SP 1095; Bus 16 Load Sequencer Test; Revision 30
- WO 392318; SP 1081.1, 18 Month 121 Auxiliary Building Special Ventilation Filter Removal Efficiency; June 8, 2010
- SP 1074A; Train A Auxiliary Building Special Vent System Quarterly Test; Revision 8
- SP 1081.1; 121 Aux Building Special Ventilation Filter Removal Efficiency Test; Revision 15
- SP-F02; Minneapolis Testing Laboratory Surveillance In-Place Leak Tests of High Efficiency Particulate Air Filters and Charcoal Absorbers at Prairie Island Nuclear Generating Plant; Revision 4
- SP 1106C; 121 Cooling Water Pump Test; Revision37
- WO 400731-01; SP1106C 121 Cooling Water Pump Test; July 17, 2010
- SP 1119; Steam Exclusion Monthly Damper Test; Revision 53

1R22 Surveillance Test

- WO 400810; SP 1090A, 11 Containment Spray Pump Quarterly; July 1, 2010
- SP 1090A; 11 Containment Spray Pump Quarterly Test; Revision 19
- CAP 1241496; Could Not Drain the 11 Containment Spray Pump Discharge Due to Valve Leakage; July 15, 2010
- WO 400740; SP 1093 D1 Diesel Generator Monthly Slow Start Test; July 12, 2010
- SP 1093; D1 Diesel Generator Monthly Slow Start Test; Revision 82
- CAP 1241061; Axial Play in Rocker Shaft on D1 Air Inlet Check; July 1, 2010
- CAP 1241045; D1 Intake Studs Loose; July 12, 2010
- WO 400744; SP 1094 Bus 15 Load Sequencer Monthly Test; July 13, 2010
- SP 1094; Bus 15 Load Sequencer Test; Revision 27
- WO 402574; SP 2090B Containment Spray Pump Quarterly Test; August 5, 2010
- SP 2090B; 22 Containment Spray Pump Quarterly Test; Revision 18

1EP6 Drill Evaluation

- Emergency Plan; Revision 41
- Prairie Island Nuclear Generating Plant Emergency Plan Drill; Revision 0
- SWI EP-500; Site Drill and Exercise Manual; Revision 16
- CAP 1242666; 24 Hour TSC Staffing Not Fully Demonstrated; July 23, 2010
- CAP 1243019; No Emergency Vehicle During Drill for Courier Sample Drivers; July 27, 2010
- CAP 1243025; Not Enough TLDs in TSC and Use of Plant Versus Site Evacuation Terminology;
- CAP 1243075; TCS Ventilation Did Not Meet SP 1689 Requirement; July 27, 2010
- CAP 1243079; TSC Upper Vent Thermostat Found Out of Position; July 27, 2010
- CAP 1243086; Shortage of TLDs and Dosimeters in TSC; July 28, 2010
- CAP 1243088; Hole in Floor Creating Safety Hazard in TSC; July 28, 2010
- CAP 1243099; Problems With TSC Laptop; July 28, 2010
- CAP 1243109; Assembly Point Guard Wasn't Informed Properly to Release Personnel; July 28, 2010
- CAP 1243125; ERO Employee Hot Line Deleted; July 28, 2010
- CAP 1243137; ERO Duty Team Meeting on July 27 Cancelled; July 28, 2010
- CAP 1243147; Water Leaking on Floor in OSC; July 28, 2010
- CAP 1243149 TSC REC Area Fax Inoperable During Drill; July 28, 2010
- CAP 1243178; Joint Information Center Equipment Difficult to Use; July 28, 2010

- CAP 1243191; Enhance FP-EP-IP-04, Start-up and Operations of SEOC/JIC; July 28, 2010
- CAP 1243195; First News Release Error; July 28, 2010
- CAP 1243198; Ensure Proper Staffing of the Joint Information Center; July 28, 2010
- CAP 1243217; EP Drill-DEP/Notification Failure; July 28, 2010
- CAP 1243220; Received Inaccurate Press Release from Joint Information Center; July 28, 2010
- CAP 1243221; OSC has Slip Hazards/Facility is Degraded; July 28, 2010
- CAP 1243222; Conduct of Drill – Offsite Drill Interjects Not Anticipated; July 28, 2010
- CAP 1243223; Sec Did Not Set Off Pagers Correctly; July 28, 2010
- CAP 1243224; Failed Objective J.01 Warning Onsite Personnel; July 28, 2010
- CAP 1243225; Emergency Plan TLDs Not Replaced During Annual Exchange; July 28, 2010
- CAP 1243235; Drill Exemptions Created Many Risk Significant Issues; July 28, 2010
- CAP 1243236; Dispatch of Repair Teams Untimely; July 28, 2010
- CAP 1243241; TSC Coordinator Proficiency; July 28, 2010
- CAP 1243242; TSC Activation Timeliness; July 28, 2010
- CAP 1243308; TSC Lacked Sense of Urgency; July 29, 2010
- CAP 1243309; Repeat Uncorrected Issues; July 29, 2010
- CAP 1243312; RP Issues Including Frisking Practices; July 29, 2010
- CAP 1243317; TSC Ventilation Clean Up Unit Dual Light Indication; July 29, 2010
- CAP 1243318; TSC Lower Level Door Does Not Latch; July 29, 2010
- CAP 1243329; TSC Ventilation System Operated Outside USAR Design Basis; July 29, 2010
- CAP 1243482; EP Drill TSC Individual Attempted to Pre-Stage; July 29, 2010
- CAP 1243494; TSC Security Bridge Communicator Location; July 29, 2010
- CAP 1243675; Observation of Radiation Worker Behaviors; July 30, 2010
- CAP 1243923; OSC Critique Lacked Rigor and Self Critical Focus; July 30, 2010
- CAP 1243964; Roles and Responsibilities Demonstrated by OSC Drill Personnel Below Expectations; July 30, 2010
- CAP 1243981; Observation of Operator Behaviors During EP Drill; July 30, 2010
- CAP 1244478; Direction on Establishing Security Bridge Line; August 5, 2010
- CAP 1244486; Consider Training Nuclear Engineers in F3.17-2; August 5, 2010
- CAP 1244499; TSC Critique Did Not Review Scenario; August 5, 2010
- CAP 1244646; Core Damage Assessment Methodology; August 6, 2010
- CAP 1244740; Drill Accountability Report Contained Unnecessary Names; August 7, 2010

2RS1 Radiological Hazard Assessment and Exposure Controls

- 5AWI 5.3.0; Key and Seal Control; Revision 11
- AR 1180416; RP Department DRUM Report; First Quarter 2009
- AR 1203565; RP Department DRUM Report; Third Quarter 2009
- AR 1204753; 11 RHR Pit Swing Gate Blocked Open; October 2009
- AR 1215148; National Source Tracking System Source Updates; January 2010
- AR 1216416; Increase in Dose rates from the Barrel Yard; February 2010
- AR 1222643; Barrel Yard Sky-Shine Increase; April 2010
- Detailed Electronic Dosimeter Alarm Logs; Various dates
- FP-RP-CRS-01; Control, Inventory and Leak Testing of Radioactive Sources; Revision 5
- PM 3111-5-2; Refueling Cavity Seal Removal, Decon, and Storage; Revision 1
- RPIP 1001; Radiation Protection Program; Revision 13
- RPIP 1008; Radiation Protection Key Control; Revision 14
- RPIP 1115; Area TLD Locations, Emergency Plan TLDs, and TLD Change Out; Revision 12
- RPIP 1118; Conducting Radiological Surveys; Revision 18
- RPIP 1121; RWP Issue; Revision 24

- RPIP 1204; Evaluation of Airborne Radioactivity; Revision 17
- RPIP 1302; Unconditional Release of Materials; Revision 20
- RPIP 1330; Satellite RCA Process; Revision 5
- RPIP 1614; RM-14 Frisker Operation and Calibration; Revision 14
- RPIP 1677; SAM-11 Small Articles Monitor Operation and Calibration; Revision 4
- RWP 1100; Valve Work; Revision 1
- RWP 1115; Reactor Head Set, Clean Flange, and Flush Cavity; Revision 1
- RWP 1116; Reactor Cavity Decon; Revision 1
- TP 2468; Unit 2 GL 2008-01 Inspections; Revision 2

2RS2 Occupational ALARA Planning and Controls

- 2R26 ALARA Report; Final Draft
- ALARA Committee Meeting Minutes; Various dates
- FP-RP-JPP-01; RP Job Planning; Revision 7
- Prairie Island Site Dose History; dated 2010
- QF 1209; Radiological Pre-Job Briefing Form; Revision 4
- QF 1227; Radiological Work Assessment Form; Revision 1
- QF 2007; Planning and Approval of High Risk or Scheduled Risk Work; Revision 2

2RS4 Occupational Dose Assessment

- Declared Pregnant Worker Documentation; 2009 and 2010
- FP-RP-BP-01; Bioassay Program; Revision 6
- FP-RP-SD-01; Special Dosimetry; Revision 06
- NVLAP Scope of Accreditation; July 2010 through June 2011
- Positive Whole Body Count Documentation; 2009 and 2010
- Radiation Occurrence Reports; Various dates
- RPIP 1107; Fetal Protection Program; Revision 10
- RPIP 1126; Contamination Monitor Alarm Response and Personnel Decontamination; Revision 24

4OA1 Performance Indicator Verification

- MSPI High Pressure Injection System Derivation Report Units 1 and 2 – Unavailability Index; August 4, 2010
- MSPI High Pressure Injection System Derivation Report Units 1 and 2 – Unreliability Index; August 4, 2010
- SP 1155A; Component Cooling System Quarterly Test Train A; Revision 20
- MSPI Heat Removal System Derivation Report Units 1 and 2 – Unavailability Index; August 2, 2010
- MSPI Heat Removal System Derivation Report Units 1 and 2 – Unreliability Index; August 2, 2010
- MSPI Emergency AC Power System Derivation Report Units 1 and 2 – Unavailability Index; August 4, 2010
- MSPI Emergency AC Power System Derivation Report Units 1 and 2 – Unreliability Index; August 4, 2010
- RPIP 3025; Chemistry Performance Indicator Reporting Instructions; Revision 4
- RPIP 3382; Reactor Coolant Sample Preparation and Analysis; Revision 12
- RPIP 3603; Sampling Unit-1 CVCS Demineralizers; Revision 10
- FP-CY-GSA-01; Operation of the Gamma Spectral Analysis Instrumentation; Revision 0

- FP-PA-PI-02; NRC/INPO/WANO Performance Indicator Reporting; Revision 06
- Monthly Effluent Release Off-Site Dose Calculations; Various dates

4OA2 Identification and Resolution of Problems

- SWI O-50; Reactivity Management; Revision 12
- SP 1320B; Pressurizer Heaters Group B Operation From Hot Shutdown Panel 18 Month Test; Revision 3
- IN 2010-06; Inadvertent Control Rod Withdrawal Event while Shutdown, February 17, 2010
- FP-OP-COO-01; Conduct of Operations; Revision 7
- Operation Logs; July 6-7, 2010
- CAP 1228173; NRC IN 2010-06 Inadvertent Control Rod Withdrawal Event; April 20, 2010
- FP-PA-OE-01; Operating Experience Program; Revision 14
- CAP 1240435; Loss of Letdown and Pressurizer Heaters Due to Bistable Failure; July 6, 2010
- 2C1.3 AOP1; Shutdown from outside the Control Room; Revision 15
- CAP 1253367; Inadequate Operating Experience Evaluation of NRC Information Notice 2010-06; October 8, 2010

4OA3 Follow-up of Events and Notices of Enforcement Discretion

- 2C15; Residual Heat Removal System Unit 2; Revision 40
- 2ES-1.2 Attachment K; Unit 2 Alignment for Switchover to Recirculation; Revision 21
- 2ES-1.2 Background Information; Revision 21
- CAP 426586; Reportability Evaluation for RHR Pit Covers Powered from Non-Safeguards Buses; date unknown
- ACE 1234661; Causal Evaluation for Unit 2 Reactor Trip During Startup; May 26, 2010
- LER 0500306/2010-02-00; Unit 2 Turbine Shutdown Due to the Loss of a Main Feedwater Pump That Resulted in a Reactor Scram; July 16, 2010
- Outage Scope Change Request 360; Replace 16012 – It Was Found Out of Tolerance by 20 Pounds; May 1, 2010
- Outage Scope Change Request 474; Replace 16012 – It Was Found Out of Tolerance by 20 Pounds; May 12, 2010
- Preventative Maintenance Procedure ICPM 2-333; 21 Feedwater Pump; Revision 20
- Fleet Procedure FP-E-SE-02; Component Classification; Revision 4
- NSP Technical Manual; NX-52163-1; Reliability Data Base-Single Failures/Reactor Trips; Revision 1
- Fleet Guidance Document; FG-E-01; Vulnerability Process; Rev. 2
- RPIP 1221; Containment In-Line Air Sampling; Revision 10
- SP 2244; Containment Air Sample Valves Quarterly Test; Revision 9
- NF-40750-1; NSSS Sample and Isolation Valves Units 1 and 2; Revision F
- Human Performance Event Investigation; 2RD-5-1 Containment Sample Valve Misposition; September 9, 2010
- CAP 1248806; Valve 2RD-5-1 Found In Open Position; September 8, 2010
- Department Clock Reset; 2RD-5-1 Containment Sample Valve Misposition; Event Date September 7, 2010
- RPIP 1221; Containment In-Line Air Sampling; Revision 10
- FP-G-DOC-03; Procedure Use and Adherence; Revision 9
- TP 2468; Unit 2 GL 2008-01 Inspections; Revision 3
- Prairie Island Team Notes; June 2, 2010
- Outage Scope Change Request # 360; May 1, 2010
- Outage Scope Change Request # 474; May 5, 2010

- ICPM 2-333; 21 Feedwater Pump Instrument Calibration; Revision 20
- FP-E-SE-02; Component classification; Revision 4
- FP-E-01; Vulnerability Process; Revision 2
- NX-52163-1; Technical Manual – Reliability Database, Single Failures/Reactor Trips; Revision 0
- CAP 1233718; Residual Heat Removal Loss of Safety Function due to Both Pit Covers Open in Mode 4; May 20, 2010
- Apparent Cause Report 1234661; Unit 2 Trip During Startup; June 28, 2010
- Calibration History for Pressure Switch 16010; no date provided
- Calibration History for Pressure Switch 16011; no date provided
- Calibration History for Pressure Switch 16047; no date provided
- Calibration History for Pressure Switch 16012; no date provided
- Calibration History for Pressure Switch 16013; no date provided
- Calibration History for Pressure Switch 16048; no date provided

4OA7 Licensee Identified Findings

- FP-G-DOC-03; Procedure Use and Adherence; Revision 9
- RPIP 1221; Containment In-Line Air Sampling; Revision 10

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
DAC	Derived Air Concentration
DHR	Decay Heat Removal
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPD	Electronic Personal Dosimeter
GL	Generic Letter
HRA	High Radiation Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
OPR	Operability Review
PARS	Publicly Available Records System
PI	Performance Indicator
RCS	Reactor Coolant System
RETS/ODCM	Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual
RFO	Refueling Outage
RHR	Residual Heat Removal
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SCCI	Substantive Cross-Cutting Issue
SDP	Significance Determination Process
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order

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Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
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 M. Schimmel from J. Giessner dated November 4, 2010.

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000282/2010004; 05000306/2010004

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