July 25, 2000

Mr. M. Wadley
President, Nuclear Generation
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT INSPECTION REPORT 50-282/2000008(DRP); 50-306/2000008(DRP)

Dear Mr. Wadley:

On May 19 through June 30, 2000, the NRC completed a safety inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection which were discussed on June 29, 2000, with Mr. J. Sorensen and other members of your staff.

This inspection was an examination of 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. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, two issues of very low safety significance (Green) were identified. These issues were determined to involve two violations of NRC requirements. However, the violations were not cited due to their very low safety significance and because they have been entered into your corrective action program. In addition, a finding from a previous inspection was also determined to be an issue of very low safety significance. That issue was also determined to involve a violation of NRC requirements but it was not cited due to its very low safety significance and because it had been entered into your corrective action program. If you contest the Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Prairie Island facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available **electronically** for public inspection in the NRC Public Document

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Sincerely,

/RA/

Roger Lanksbury, Chief
Reactor Projects Branch 5

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

cc w/encl: Site General Manager, Prairie Island
Plant Manager, Prairie Island
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos: 50-282, 50-306
License Nos: DPR-42, DPR-60

Report No: 50-282/2000008(DRP); 50-306/2000008(DRP)

Licensee: Northern States Power Company

Facility: Prairie Island Nuclear Generating Plant

Location: 1717 Wakonade Drive East
Welch, MN 55089

Dates: May 19, 2000, through June 30, 2000

Inspectors: S. Ray, Senior Resident Inspector
S. Thomas, Resident Inspector
D. Funk, Emergency Preparedness Analyst
M. Pohida, Risk Analyst, Office of Nuclear Reactor Regulation

Approved by: Roger Lanksbury, Chief
Reactor Projects Branch 5
Division of Reactor Projects

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW, or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

SUMMARY OF FINDINGS

IR 05000282-00-08, IR 05000306-00-08, on 05/19-06/30/2000; Northern States Power Company; Prairie Island Nuclear Generating Plant; Units 1 & 2; Refueling and Outage Activities.

The inspection was conducted by resident inspectors, a regional inspector, and a risk analyst. This inspection identified three green issues with three noncited violations. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process.

Cornerstone: Mitigating Systems

- GREEN. The licensee identified two occurrences of maintenance procedure implementation errors during steam generator manway cover installation, and poor scheduling of site-wide safety meetings which directly contributed to Unit 2 being kept in a condition of increased risk for an extended period of time. The delays resulted in the licensee spending approximately 14 additional hours at reduced inventory conditions with a time to boiling of about 25 minutes should decay heat removal capability have been lost. The maintenance procedure implementation errors were determined to be two examples of a Non-Cited Violation.

The inspectors determined that these issues were of very low safety significance because the likelihood of an initiating event which would cause a loss of residual heat removal capability was very small during the 14-hour window and, even if it did occur, the licensee had adequate mitigation capability. (Section 1R20.1)

- GREEN. As discussed in Inspection Report 50-282/2000005(DRP); 50-306/2000005(DRP), the licensee identified that a maintenance error during the 22 steam generator nozzle dam installation led to the need to keep Unit 2 in a configuration of increased risk with reduced inventory for longer than it otherwise would have been. The issue was determined to be a Non-Cited Violation.

The inspectors determined that this issue was of very low safety significance because the likelihood of an initiating event which would cause a loss of residual heat removal capability was small during the approximately 7 extra hours in reduced inventory and, even if it did occur, the licensee had adequate mitigation capability. (Section 1R20.2)

- GREEN. The inspectors identified a Non-Cited Violation for Unit 2 as a result of the licensee not following a procedure which required evaluating proposed work for impact on system and plant operation. The failure to perform this evaluation resulted in a temporary modification to a containment ventilation duct causing the failure of a draindown automatic self-limiting feature and the need for reactor operators to secure a reactor coolant system draining evolution when in reduced inventory conditions.

The inspectors determined that this issue was of very low safety significance because the location where the drain line penetrated the reactor coolant system hot leg piping would have prevented the reactor coolant system inventory from decreasing to a point that would have impacted residual heat removal pump operability. (Section 1R20.3)

<u>Report Details</u>

Summary of Plant Status: Unit 1 operated at or near full power for the entire inspection period. Unit 2 was in a refueling outage at the beginning of the inspection period. Unit 2 was taken critical on June 6, 2000, and the generator was placed on the grid on June 7. Unit 2 reached full power on June 10 and operated at or near full power for the remainder of the inspection period.

1.REACTOR SAFETY

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

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors performed walkdowns and record reviews to determine if various plant systems had been properly protected from the effects of high summer temperatures and potential tornadoes. The inspectors concentrated most of the inspection efforts on the instrument air system and emergency diesel generators because of their importance in preventing initiating events and mitigating accidents. The following documents were reviewed as part of this inspection:

- Periodic Test Procedure (TP) 1636, "Summer Plant Operation," Revision 6, completed on May 5, 2000;
- Surveillance Test Procedure (SP) 1039, "Tornado Hazard Monthly Site Inspection," Revision 5, completed on June 6, 2000;
- Operating Procedure C34, "Station Air System," Revision 16, Section 5.11, "Aligning Air Compressor Cooling Water Supply for Summer Operation";
- Prairie Island Nuclear Generating Plant Individual Plant Examination of External Events (IPEEE), NSPLMI-96001, Revision 0, Sections C.2.1, "Severe Temperature Transients (Extreme Heat and Extreme Cold)," and C.2.2, "High Winds and Tornadoes"; and
- Abnormal Procedure (AB)-2, "Tornadoes."

b. Issues and Findings

There were no findings identified during this inspection.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed walkdowns of trains of safety significant systems. These walkdowns were performed to verify the operability of the redundant train coincident with the time that the opposite train was out-of-service for planned maintenance or testing. The systems were selected for this inspection due to their high importance as core damage mitigating systems for several accident sequences. The inspectors ensured that the configuration of the trains was in accordance with applicable operating checklists and that the systems could still perform their required design basis functions. The following trains were inspected:

- the 22 auxiliary feedwater train during testing of the 21 auxiliary feedwater pump, and
- the 12 component cooling train while the 11 component cooling heat exchanger was out-of-service due to maintenance.

As part of this inspection, the inspectors reviewed the following documents:

- Integrated Checklist C1.1.14-1, "Unit 1 Component Cooling System," Revision 16;
- System Prestart Checklist C28-7, "Auxiliary Feedwater System Unit 2," Revision 42;
- System Prestart Checklist C28-18, "22 Turbine Driven Auxiliary Feedwater Pump," Revision 1; and
- Integrated Checklist C1.1.27-2A, "Part 1 Main and Auxiliary Steam Unit 2," Revision 28.

b. Issues and Findings

There were no findings identified during this inspection.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted fire protection walkdowns focused on the control of transient materials, available fire protection systems and equipment, and the condition and operating status of installed fire barriers. The inspectors selected the following fire areas for inspection based on their overall contribution to internal fire risk, as documented in the IPEEE:

- Fire Area 13, control room;
- Fire Area 69, Unit 1 turbine building, 695-foot elevation;
- Fire Area 69, Unit 1 turbine building, 715-foot elevation; and
- Fire Area 73, Unit 2 auxiliary building, 695-foot elevation.

As part of this inspection, the inspectors reviewed the following documents:

- IPEEE, NSPLMI-96001, Appendix B, "Internal Fires Analysis," Revision 1;
- Plant Safety Procedure F5 Appendix A, "Fire Strategies," Revisions 5 and 6;
- Plant Safety Procedure F5 Appendix D, "Impact of Fire Outside Control/Relay Room," Revision 5; and
- Plant Safety Procedure F5 Appendix E, "Fire Protection Safe Shutdown Analysis Summary," Revision 6.

b. Issues and Findings

There were no findings identified during this inspection.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule requirements for the following systems:

- feedwater;
- heater drains; and
- turbine and moisture separator.

All three systems were selected for evaluation based on their potential to cause a reactor plant transient or reactor trip. Portions of the feedwater system can also be used to mitigate the consequences of certain accidents that could result in potential off-site exposure. Another factor the inspectors considered during the selection of the heater drains and turbine and moisture separator systems was that these systems had been identified by the licensee as systems whose performance, although meeting their performance criteria, had degraded. As part of this inspection, the inspectors reviewed the 1999 Annual and First Quarter Equipment Performance Report, dated May 2, 2000, and the Prairie Island Maintenance Rule System Basis Document, as well as the following work orders (WOs) and condition reports:

- General Condition Report 19960156, "Tube Plug Failure in 25B Feedwater Heater";
- WO 9905635, "Investigate Loop B Main Feed Reg Valve Indication/Operation";
- WO 9911102, "B Loop FRV [feedwater regulating valve] has Hi Deviation Position/Output";
- WO 9900010, "Isolate CV [control valve]-3 During Startup";
- WO 9902148, "CV-31176 Sluggish Operation";
- WO 9901623, "Check out EH [electrohydraulic] System Before Unit Outage";
- WO 9913280, "Operate Unit 1 With 1 Heater Drain Tank Pump to Facilitate Repairs";
- WO 9901885, "CV 31064 Stuck Open"; and
- WO 9906032, "15 Feedwater Heater High Level Transmitter is sending a false High Level Signal."

b. <u>Issues and Findings</u>

There were no findings identified during this inspection.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

- The inspectors reviewed the risk profile and work schedule of maintenance activities performed between the dates of May 22-27, 2000. The inspectors also monitored the progress of the risk significant activities daily. The specific work activities evaluated included Unit 2 reduced inventory operations, relay testing which took the D6 emergency diesel generator out-of-service, monthly surveillance testing of the 12 motor-driven auxiliary feedwater pump, and significant electrical switching activities which de-energized switchyard Bus 2 to support work which restored the 8H12 motor-operated disconnect to service. The inspectors verified that the equipment required to support reduced inventory and shutdown operations for Unit 2 and the availability of the required redundant trains to support power operations for Unit 1 were available. As part of this inspection, the inspectors reviewed the "Prairie Island Weekly Planning Meeting Results, 5/20/00-5/26/00," and held discussions with members of the licensee's risk assessment group.

- The inspectors reviewed the planning, attended a planning meeting, attended the pre-job briefing, and observed the conduct of work to transfer the 2RS transformer from switchyard Bus 2 to Bus 1 in accordance with WO 0004600. The work was considered significant because of the increased probability of a loss of offsite power to the vital buses during the breaker manipulations. As part of this inspection, the inspectors reviewed the "Prairie Island Weekly Planning Meeting Results, 6/10/00-6/16/00."

- The inspectors reviewed the planning, attended planning meetings, and observed selected work for the period of June 17-23, 2000. The inspectors also reviewed the effect that emergent work for a problem with the unloader valve on the 123 instrument air compressor had on the risk profile for the rest of the week and observed how the licensee adjusted the planned maintenance schedules for the 122 instrument air compressor and the component cooling heat exchangers to control the overall risk. As part of this inspection, the inspectors reviewed the "Prairie Island Weekly Planning Meeting Results, 6/17/00-6/23/00," the "Prairie Island Daily Non-Outage Work Planning Meeting Package for June 21, 2000," and the "6/22/2000 Daily At-Power Risk Report."

b. Issues and Findings

There were no findings identified during this inspection.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed a sampling of operability evaluations for safety significant systems and conditions to determine that operability was justified, that availability was assured, and that no unrecognized increase in risk had occurred. The following evaluations were reviewed:

- Condition Report 20002019, “Condenser Emergency Makeup MV [motor-operated valve] 32041 & MV 32042 - Investigate MV’s use if Auxiliary Feedwater Pumps are Started”; and
- Condition Report 20001438, “Discrepancy Between Actual and Assumed Operating Conditions used in Westinghouse Loss of Coolant Accident Hydraulic Force Calculations.”

As part of this inspection, the inspectors reviewed the following additional documents:

- NSPAD - 8606P, “Prairie Island Units 1 and 2 Auxiliary Feedwater System Reliability Study,” Revision 0; and
- Updated Safety Analysis Report , Section 4, “Reactor Coolant System,” Revision 21.

b. Issues and Findings

There were no findings identified during this inspection.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors evaluated the following new operator workarounds (OWAs) to determine if the applicable system function was impacted or if the OWA affected the operator’s ability to implement abnormal or emergency operating procedures:

- OWA 20000991, “Unit 1 Loop B Pressurizer Spray Valve CV [Control Valve] 31225 Appears to be Stuck Open”; and
- OWA 20001718, “ZX [containment ventilation] System does not Perform as Designed.”

As part of this inspection, the inspectors reviewed the following additional documents:

- Condition Report 20000714, “Unit 1 Loop B Pressurizer Spray Valve CV 31225 Appears to be Stuck Open”;
- Condition Report 20001126, “Assess Current State of Unit 1 and Associated Equipment and Determine Course of Action if Required”;
- Action 20001152, “Develop a Forced Outage Plan for 3-day, 7-day, and 21-day Outages”; and
- Action 19993211, “Improvements are Needed to the ZX System to Assure Cooling is Operating Properly for Maintenance and Equipment Life.”

b. Issues and Findings

There were no findings identified during this inspection.

1R19 Post-Maintenance Testing

a. Inspection Scope

- The inspectors observed testing and evaluated post-maintenance test data for the 123 instrument air compressor to ensure that the testing demonstrated that the compressor was capable of performing its design function. The testing was performed following replacement of the unloader valve and calibration of the unloading pressure switches in accordance with WO 0006640, "123 Instrument Air Compressor Not Unloading Properly," and WO 0004424, "123 Station Air Compressor Load/Unload Pressure Switches." This post-maintenance test was considered important because the licensee planned to remove the 122 compressor from service immediately after the 123 compressor was returned to service and the core damage frequency would have been significantly affected if both compressors had been inoperable during later scheduled work on the component cooling heat exchangers. To help determine whether the post-maintenance test was adequate, the inspectors discussed the root cause of the unloader valve problem with the maintenance supervisor and system engineer, inspected the valve after disassembly, and reviewed the maintenance history of the compressor.

- The inspectors witnessed testing after replacement of the reference average reactor coolant temperature (T_{ref}) module for Unit 1. This post-maintenance test was considered significant because failure of the module had caused unexpected control rod movement which could have led to a transient, and the compensatory actions which had been in place (placing the rod control system in manual) could have complicated the plant response to a transient, such as a turbine runback. As part of this inspection, the inspectors reviewed WO 0006965, "T_{ref} Indication Erratic at 1TM-401P." The inspectors verified that the module output was properly calibrated and had been verified to be stable before the rod control system was placed back in automatic and that the output stability was monitored for a sufficient time after the completion of the work to have assurance that the problem had been corrected.

b. Issues and Findings

There were no findings identified during this inspection.

1R20 Refueling and Outage Activities

.1 Extended Reduced Inventory Operation

a. Inspection Scope

The inspectors evaluated maintenance errors and scheduling decisions that impacted the time that the Unit 2 reactor coolant system (RCS) remained in a reduced inventory condition during the refueling outage. As part of this inspection, the inspectors reviewed the following documents:

- Maintenance Procedure D27.6, “Steam Generator Primary Manway Replacement S.G. [steam generator] No. 22,” Revision 31;
- Condition Report 20001885, “During the Installation of 22 Steam Generator Manways, Quality Control and a Machinist Determined the Lubricant Used on the Studs Was Not Correct”;
- Condition Report 20001877, “Delays With Primary Manway Removal and Replacement Increased the Time at Reduced Inventory in the RCS”; and
- Condition Report 20001896, “Quality Control Not Contacted for Witness Point #2 (WO 9911675), 22 Steam Generator Manway Installation Stud Baseline Measurement [Rework].”

b. Issues and Findings

Maintenance procedure implementation errors and a poor scheduling decision directly contributed to Unit 2 being kept in a condition of increased risk for an extended period of time.

On May 23, 2000, the Unit 2 RCS was drained to the top of the hot legs to facilitate the removal of the steam generator nozzle dams, subsequent to steam generator eddy current testing and maintenance. Following the nozzle dam removal and requisite steam generator bowl inspections, the hot leg and cold leg steam generator primary manway covers were installed. The inspectors noted several delays had occurred during the steam generator manway cover replacement work. The inspectors discussed the delays listed below with the system engineer responsible for overseeing the work.

- During the performance of Maintenance Procedure D27.6, workers missed a Quality Control witness point on Step 6.2.4 (measure baseline center rod depth on all studs). Missing the witness point required that the step be repeated. This deficiency was entered into the licensee corrective action program as Condition Report 20001896.

- Prior to installing manway covers on the 22 steam generator, maintenance personnel notified the steam generator system engineer that they believed the wrong lubricant (Nickel Never Seize) had been used on the steam generator manway studs. Maintenance Procedure D27.6, Step 6.2.5 required, in part, that the stud threads and washers be lubricated with Fel Pro N5000 and that the control number for the lubricant be recorded in the procedure. The control number for the lubricant had not been recorded in the procedure and positive identification of the lubricant that was used was not possible. After the suspect lubricant had been removed from the studs, Step 6.2.5 was repeated using the Fel Pro N5000 lubricant. This deficiency was entered into the licensee corrective action program as Condition Report 20001885.

- At selected times during the refueling outage, the licensee conducted “Stand-up for Safety” meetings. The purpose of those meetings was to refocus personnel on the importance of safe work practices. During the time that those meetings were held, all maintenance activities were stopped so that personnel could attend. However, these meetings coincided with the time that the steam generator manways covers were being replaced, which caused work delays while in a reduced inventory condition. This was entered into the licensee corrective action program and was being evaluated as part of Condition Report 20001877.

The steam generator engineer informed the inspectors that the delays caused by the maintenance procedure performance errors and the work stoppage for the safety meetings required that the RCS be kept in a reduced inventory condition for approximately 14 additional hours.

The inspectors reviewed this event for risk significance using Inspection Manual Chapter 0609, “Significance Determination Process (SDP),” Original Revision, Appendix G, “Shutdown Safety SDP.” These human performance issues and scheduling issue resulted in the licensee spending approximately 14 hours, beyond the time required had the errors not occurred, at reduced inventory conditions with a time to boiling of about 25 minutes should decay heat removal have been lost. Since the probability of loss of decay heat removal, reactor coolant inventory, or electrical power increased with exposure time, the inspectors determined that the issue was a finding of potential risk significance requiring a Phase 2 SDP analysis, in accordance with Table 1 of Appendix G, and the finding was referred to an NRC Risk Analyst from the Office of Nuclear Reactor Regulation for further analysis and determination of actual risk.

The Phase 2 risk analysis documented that there were three aspects of reduced inventory operation from which increased risk could be derived. These aspects were as follows:

- The loss of residual heat removal (RHR) due to the operator exceeding the intended level while establishing reduced inventory conditions or failing to maintain level once established;
- Not having the required standby equipment, in addition to both RHR pumps, available to inject water into the RCS; and
- Other shutdown initiators which caused the loss of RHR, such as loss of offsite power, failure of RHR components or required support systems, or losses of RCS inventory not specifically caused by failure to control level while in reduced inventory conditions.

As discussed later in Section 1R20.3, the drainpath used by the licensee incorporated a self-limiting feature which limited, by system configuration, the water level to which the RCS could be drained which, in turn, ensured the availability of the RHR pumps. Also, during this time, the inspectors verified that the licensee had the required standby equipment available, in addition to both RHR pumps, to inject water into the RCS. This left the third aspect as the only potential risk contributor for extended reduced inventory operation. The NRC Risk Analyst concluded that if each item on the SDP checklist (Pressurized Water Reactor Cold Shutdown and Refueling Operation with the RCS open and Refueling Cavity <23' and Time to Boiling <2 hours) were met, there was little additional risk for core damage (<1E-6 core damage frequency) because the likelihood of the initiator which caused a loss of RHR was small during the 14-hour window. In addition, if the event did occur, the licensee had adequate mitigation capability. Due to the very low safety significance, this issue was considered to be within the licensee response band (Green). The finding was assigned to Unit 2.

Technical Specification 6.4 required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation), Revision 2, Appendix A, February 1978. Among those procedures were procedures for performing maintenance. Section 9.a of Regulatory Guide 1.33 stated, in part, that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. On May 23, 2000, during the performance of Maintenance Procedure D27.6, Step 6.2.4, maintenance workers performed baseline center rod depth measurements on the steam generator manway studs without a Quality Control representative present, as required by the procedure. Also on May 23, 2000, during the performance of D27.6, Step 6.2.5, maintenance workers did not document the control number of the lubricant used on the stud threads and washers, as required by the procedure. These two examples of failure to follow a maintenance procedure are considered a Non-Cited Violation (50-306/2000008-01(DRP)) consistent with Section VI.A.1 of the NRC's Enforcement Policy. This issue has been entered into the licensee's corrective action program as level one Condition Report 20001877, "Delays With Primary Manway Removal and Replacement Increased the Time at Reduced Inventory in the RCS" and a Quality Assurance Finding 20001984, "Missed QC [Quality Control] Inspection Points Having Impact on Work Sample that Could Affect Ability to Assure Quality of Work." The licensee was also conducting a root cause investigation, but had not completed the investigation by the end of the inspection period.

.2 <u>(Closed) Apparent Violation 50-306/2000005-01(DRP)</u>: Failure to Properly Implement Procedures for Installing Nozzle Dams on the 22 Steam Generator. This issue was previously discussed in Inspection Report 50-282/2000005(DRP); 50-306/2000005(DRP), Section 1R20. The issue involved a maintenance error which resulted in Unit 2 being required to remain in a higher than normal risk configuration for a longer time than it otherwise should have. The risk characterization was left open pending an evaluation by an NRC Risk Analyst. The circumstances of the finding and configuration of the plant were very similar to the finding discussed in Section 1R20.1 of this report. As discussed in that section, the Risk Analyst completed an evaluation and determined that the finding was of very low risk significance. Thus, the finding from the previous report was considered to be within the licensee response band (Green) and the Apparent Violation is considered to be a Non-Cited Violation (50-306/2000008-02(DRP)), consistent with Section VI.A.1 of the NRC's Enforcement Policy. The licensee entered this issue into its corrective action program as Condition Report 20001336, "22 SG Bowl Plug Installed in Primary Manway Drain Hole, Bowl Plug Should Have Been Installed in Nozzle Drain Hole."

.3 Temporary Equipment Installation that Complicated Draining the RCS to the Top of the Hot Leg Piping

a. Inspection Scope

The inspectors observed the draining of the RCS from approximately 1 foot below the reactor vessel flange to the top of the RCS hot legs in preparation for steam generator nozzle dam removal. The inspectors reviewed the installation of the temporary ventilation filter/fan unit attached to the containment cleanup ventilation duct located in Unit 2 containment. This temporary equipment installation was selected for evaluation because it directly impacted the performance of the RCS draindown evolution conducted on May 23, 2000. Documents reviewed as part of this inspection included:

- Project Description for Modification 92L362, PART A, “RCS Drain Down Modification,” Revision 2;
- WO 0000240, “Remove/Install Clean-up Fan Ductwork to Allow a Portable High Efficiency Particulate Air Filter to be Used for Steam Generator Primary Work Per Attached Procedure”;
- Prairie Island Administrative Work Instruction (5AWI) 3.2.2, “Work Control Package Preparation and Review,” Revision 31;
- Special Operating Procedure 2D2, “RCS Reduced Inventory Operation,” Revision 11;
- 5AWI 6.5.0, “Temporary Modifications,” Revision 8; and
- Condition Report 20001844, “Siphoning During RCS Draindown 2D2.1 Following Refueling, Manually Stopped Draining at 26.25 Inches In Accordance With Precaution at 5.2.11.”

b. Issues and Findings

The licensee failed to adequately evaluate the impact of installing a temporary ventilation/filter, located on the suction of the containment cleanup duct, on the RCS vents used during the draindown to establish reduced inventory conditions.

On May 23, 2000, the inspectors observed the draining of the Unit 2 RCS to the top of the hot leg piping per Special Operating Procedure 2D2.1, “RCS Reduced Inventory Operations After Pool Flood,” Revision 11. This was a planned evolution performed to facilitate the removal of the nozzle dams in the 21 and 22 steam generators. The drain path utilized by this procedure incorporated a self-limiting feature which was designed to automatically stop the draining from the RCS when water level reached the top of the RCS hot legs, which was approximately 28 inches (0 inches = bottom of the hot leg nozzles). The inspectors noted that the self-limiting feature did not function properly during the performance of the drain down and that the operators took appropriate actions to secure the draining when level reached 26.25 inches. After restoring the RCS level to the prescribed band of 27.25 to 30.25 inches, the senior reactor operator in charge of the drain down dispatched a system engineer to investigate why the self-limiting feature did not work.

After the system engineer had inspected the vent path utilized as a vacuum break for the self-limiting feature, he informed the senior reactor operator and the inspector that due to the installation of a temporary ventilation fan on the containment cleanup ventilation duct to which the self-limiting feature's vacuum break line was attached, a negative pressure condition existed in the ventilation ducting, preventing proper vacuum break operation.

The inspectors discussed the installation of the temporary ventilation fan with the General Superintendent Engineering, the General Superintendent Radiation Protection and Chemistry, and the Superintendent Mechanical Systems/Programs Engineering. The inspectors were informed that the temporary ventilation filter/fan had been installed to improve the air quality in the area where steam generator manway work was being performed. This filter/fan had been installed using the normal work order process and was not deemed to be a temporary modification since the filter/fan was only being connected to an "outage tool" [containment cleanup ventilation duct]. After the inspectors questioned how alterations to the containment cleanup ventilation duct, which also impacted the performance of the RCS vent tubing during refueling operations, were controlled, they were informed that Modification 92L362, which installed the RCS vent tubing, had not adequately prescribed or controlled the conditions required in the containment cleanup ventilation duct that facilitated proper draindown self-limiting vacuum breaker operation. The inspectors were also informed by the licensee that engineering sensitivity to the installation of "outage tools" and their impact on shutdown plant operation needed to be improved. To prevent recurrence of this problem, the licensee informed the inspectors that the termination point of the draindown self-limiting vacuum breaker would be moved from the containment cleanup ventilation ducting prior to being used during the next refueling outage on each unit.

The inspectors reviewed this event for risk significance using Inspection Manual Chapter 0609, "Significance Determination Process (SDP)," Original Revision, Appendix G, "Shutdown Safety SDP." The error resulted in improper vacuum break operation which required the operators to take action to secure the draindown. The inspectors concluded that because of the physical location where the drain line penetrated the RCS hot leg piping, the RCS level could not have decreased to a point that would have impacted residual heat removal pump operability. Since residual heat removal was not impacted and the amount of water that could be drained was limited by system configuration and alignment, the issue did not require a Phase 2 analysis, was of very low safety significance, and was considered to be within the licensee response band (Green). The finding was assigned to Unit 2.

Technical Specification 6.4 required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulator Guide 1.33, Revision 2, Appendix A, February 1978. Among those procedures were procedures for the general control of maintenance, of which 5AWI 3.2.2 was an example. During the preparation of WO 00000240, which gave guidance on the installation of the temporary ventilation fan/filter unit attached to the containment cleanup ventilation duct, the licensee failed to adequately implement 5AWI 3.2.2, Step 6.4.2, which required that the work control package plant sponsor evaluate the impact of the proposed work on system and plant operation. This is considered a Non-Cited Violation, consistent with Section VI.A.1 of the NRC's Enforcement Policy (50-306/2000008-03(DRP)). This issue has been entered into the licensee corrective action program as part of Condition Report 20001844.

.4 Other Refueling Outage Activities

a. Inspection Scope

The inspectors continued to observe activities associated with the Unit 2 refueling outage that began on April 28, 2000. The inspectors reviewed configuration management, clearance activities, outage work, and startup activities for management of risk, conformance to the applicable procedures, and compliance with the Technical Specifications. The following major activities were observed:

- outage planning meetings;
- containment close-out inspections;
- reactor startup;
- physics testing; and
- core verification (by review of the Unit 2, Cycle 20, core verification videotape).

In addition to attending several outage planning meetings and pre-evolution briefings, the inspectors also reviewed the following documents:

- Special Operating Procedure 2D2, “RCS Reduced Inventory Operation,” Revision 11;
- Operating Procedure 2C15, “Residual Heat Removal System,” Revision 18;
- Operating Procedure 2C19.1, “Containment System Integrity - Unit 2,” Revision 9;
- SP 1750 [2750], “Post Outage Containment Close-out Inspection,” Revision 17;
- Operating Procedure 2C1.2, “Unit 2 Startup Procedure,” Revision 22;
- Maintenance Procedure D30, “Post Refueling Startup Testing,” Revision 31;
- Maintenance Procedure D31, “Reactivity Computer Checkout,” Revision 6;
- Maintenance Procedure D32, “Temperature Coefficient Measurement At Hot Zero Power,” Revision 8;
- Maintenance Procedure D34, “Boron Endpoint Measurement,” Revision 6; and
- NSPNAD-00004, “Prairie Island Unit 2 Cycle 20 Final Reload Design Report (Reload Safety Evaluation) and USAR [Updated Safety Evaluation Report] Update,” Revision 1, Figure 4.1, “Prairie Island Unit 2 Cycle 20 Core Loading Pattern.”

b. Issues and Findings

There were no findings identified during this inspection.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors verified, by witnessing surveillance testing and reviewing test data, that the equipment tested by the SPs listed below met Technical Specifications, the Updated

Safety Analysis Report, and licensee procedural requirements, and demonstrated that the equipment was capable of performing its intended safety functions. The following tests were evaluated:

- SP 2083, "Unit 2 Integrated SI [safety injection] Test With A Simulated Loss of Offsite Power," Revision 23; and
- SP 1089, "RHR Pumps and Suction Valves From RWST [refueling water storage tank] Quarterly Test," Revision 49.

b. Issues and Findings

There were no findings identified during this inspection.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspector reviewed Revision 21 to the Prairie Island Nuclear Generating Plant Emergency Plan which was submitted by licensee letter, dated May 17, 2000, to verify that the changes did not decrease the effectiveness of the plan. The emergency plan revision was submitted in accordance with 10 CFR 50.54(q).

b. Issues and Findings

There were no findings identified during this inspection. The inspectors initial review of these changes will be followed up by an onsite inspection by an Emergency Preparedness Specialist.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed a licensee simulator scenario, which required two event classifications and two notifications, to verify the adequacy of the licensee's emergency classifications, notifications, protective action recommendations, and critique. The simulator scenario observed was considered an opportunity which contributed to Emergency Response Organization Drill/Exercise Performance and Emergency Response Organization Participation Performance Indicators.

b. Issues and Findings

There were no findings identified during this inspection.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Safety System Functional Failures

a. Inspection Scope

The inspectors verified the Safety System Functional Failure Performance Indicator data reported by the licensee for 1st Quarter 1999 through 1st Quarter 2000 for Unit 1 and Unit 2. This was accomplished in part through evaluation of the Limiting Conditions for Operation Log times, review of applicable WOs, and discussions with licensee personnel. The following documents were included as part of the review for this inspection:

- LER 50-282/990001; 50-306/990001, "Unit 1 Reactor Trip Following Failure of Station Auxiliary Transformer"; and
- LER 50-282/990007-01; 50-306/990007-01, "Loss of Control Room Special Ventilation Function Due to Broken Latch Pins on Control Room Chiller Doors."

b. Issues and Findings

There were no findings identified during this inspection.

4OA3 Event Followup

Cornerstones: Initiating Events, Mitigating Systems

.1 (Closed) Licensee Event Report (LER) 306/2000-001-00 (2-00-01): Reactor Trip from 22 percent Power While Shutting Down for Refueling, Caused by Feedwater Heater Hi Hi Level Turbine Trip Signal. This event was discussed in NRC Inspection Report 50-282/2000005(DRP); 50-306/2000005(DRP), Section 4OA3.2. No new issues were revealed by the LER.

.2 (Closed) LER 306/2000-002-00 (2-00-02): Discovery that PORV [power operated relief valve]/Block Valve Cable in Containment Does Not meet Appendix R Separation Criteria. This event was discussed in NRC Inspection Report 50-282/2000005(DRP); 50-306/2000005(DRP), Section 4OA3.3, where it was classified as a Non-Cited Violation in the licensee response band (Green). No new issues were revealed by the LER.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Sorensen and other members of licensee management on June 29, 2000. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Amundson, General Superintendent Engineering
T. Breene, Manager Nuclear Performance Assessment
J. Goldsmith, General Superintendent Engineering, Nuclear Generation Services
A. Johnson, General Superintendent Radiation Protection and Chemistry
G. Lenertz, General Superintendent Plant Maintenance
D. Schuelke, Plant Manager
T. Silverberg, General Superintendent Plant Operations
M. Sleigh, Superintendent Security
J. Sorensen, Site General Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-306/2000008-01(DRP)	NCV	Failure to Properly Implement Procedure for Steam Generator Manway Replacement; Missed QC Witness Point and Did Not Document Control Number of the Lubrication Used on the Stud Threads and Washers (Section 1R20.1)
50-306/2000008-02(DRP)	NCV	Failure to Properly Implement Procedures for Installing Nozzle Dams on the 22 Steam Generator (Section 1R20.2)
50-306/2000008-03(DRP)	NCV	Failure to Properly Implement Procedure for Work Control Package Preparation While Preparing Work Package to Install Temporary Ventilation on Containment Cleanup Duct During Refueling Outage (Section 1R20.3)

Closed

50-306/2000005-01(DRP)	AV	Failure to Properly Implement Procedures for Installing Nozzle Dams on 22 Steam Generator (Section 1R20.2)
306/2000-001-00 (2-00-01)	LER	Reactor Trip from 22 percent Power While Shutting Down for Refueling, Caused by Feedwater Heater Hi Hi Level Turbine Trip Signal (Section 4OA3.1)
306/2000-002-00 (2-00-02)	LER	Discovery that PORV/Block Valve Cable in Containment Does Not meet Appendix R Separation Criteria (Section 4OA3.2)

LIST OF ACRONYMS USED

AB	Abnormal Procedure
AC	Alternating Current
AFW	Auxiliary Feedwater
AV	Apparent Violation
AWI	Administrative Work Instruction
CFR	Code of Federal Regulations
CV	Control Valve
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
FR	Federal Register
IPEEE	Individual Plant Examination of External Events
LER	Licensee Event Report
MV	Motor-Operated Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OWA	Operator Workaround
PERR	Public Electronic Reading Room
PM	Preventive Maintenance Procedure
PORV	Power Operated Relief Valve
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SP	Surveillance Test Procedure
TP	Periodic Test Procedure
WO	Work Order