U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	50-282/98015(DRP); 50-306/98015(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	July 31 through September 10, 1998
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Senior Resident Inspector (acting) S. Thomas, Resident Inspector
Approved by:	M. Kunowski, Acting Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Unit 1 and Unit 2
NRC Inspection Report 50-282/98015(DRP); 50-306/98015(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The planned power reduction on Unit 1 was conducted in a controlled and deliberate manner, with good control of core reactivity and effective supervisory oversight. (Section O1.2)

- The material condition of the 11, 12, 21, and 22 station batteries was good. The surveillance and maintenance procedures for the batteries incorporated Technical Specification requirements and included Institute of Electrical and Electronics Engineers (IEEE) and battery vendor maintenance and testing recommendations. The licensee was effectively monitoring battery performance. (Section O2.1)

- The licensee was implementing a comprehensive Year 2000 Readiness Management plan to address the computer readiness issues discussed in NRC Generic Letter 98-01, "Year 2000 Readiness of Computer Systems at Nuclear Power Plants." (Section O2.2)

Maintenance

- All the routine maintenance activities and surveillance tests observed by the inspectors were conducted well and the licensee used safe work practices and demonstrated good communication and coordination between the control room operators and workers performing the work/tests. (Section M1.1)

- Throughout the D1 diesel generator outage, good coordination was demonstrated between operations, engineering, maintenance, and instrumentation and control personnel. System engineers demonstrated ownership of their systems, contributed information during many briefings, and helped coordinate efforts at the work site. (Section M1.2)

- The inspectors identified that maintenance personnel did not perform a charcoal filter tray removal and replacement work activity in accordance with applicable procedures in violation of Technical Specification requirements. Specifically, maintenance personnel failed to follow the surveillance procedure as written, implement the temporary change procedure process, and inform supervision that they had deviated from the surveillance procedure. Considerable management attention and focus had been placed on procedure quality, adherence, and compliance over the last several months. Overall, these procedure quality and adherence improvement initiatives have been effective in improving overall performance in these areas. (Section M1.3)

- Through a good questioning attitude, system engineers identified two issues with the Reactor Coolant System (RCS) vent system. Once identified, conservative and timely corrective actions were taken to address each issue. (Section M3.1)

<u>Engineering</u>

- System engineers continued to demonstrate ownership of their respective systems. The detailed system knowledge possessed by these engineers routinely aided in the successful briefing, coordination, and completion of many surveillance procedures and maintenance activities. (Section E2.2)

- During a review of the Updated Safety Analysis Report (USAR) and heavy load documents, the licensee was unable to confirm the weight of the reactor vessel head used in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants - Resolution of TAP A-36," load drop calculations. This finding resulted from a good questioning attitude by engineering personnel and demonstrated the comprehensive nature of the ongoing USAR update project. (Section E3.1)

Report Details

Summary of Plant Status

The licensee reduced power on Unit 1 to about 40 percent on August 1-2, 1998, in order to conduct repairs on a condenser manway gasket. The unit was returned to full power and remained there for the remainder of the inspection period. Unit 2 operated at full power for the entire inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (IPs 71707, 92901)

The inspectors conducted frequent reviews of plant operations. The reviews included observations of control room evolutions, shift turnovers, pre-job briefings, communications, control room access management, logkeeping, control board monitoring, and general control room decorum. Updated Safety Analysis Report (USAR), Section 13, "Plant Operations," Revision 15, was reviewed as part of the inspection.

b. Observations and Findings

- On August 11, 1998, the inspectors noted that with both units at 100 percent power, the main generator frequency meter (41195) on Unit 1 indicated 60.1 Hz while the main generator frequency meter (41716) on Unit 2 indicated 59.8 Hz. Since both units were synchronized to the same grid system, the main generator frequencies should have been identical. The inspectors contacted two electrical system engineers and reviewed the following documents:

  - TP 1828, "Panel E1 Indicating Meters Calibration Procedure," Revision 2;
  - TP 2828, "Panel E2 Indicating Meters Calibration Procedure," Revision 3;
  - Drawing NF-40777-1, "Interlock Logic Diagram Turbine Generator System," Revision J;
  - Drawing NF-40777-10, "Interlock Logic Diagram Turbine Generator System Unit No. 1," Revision D, and
  - Drawing NF-40019-22, "Interlock Logic Diagram Gen. 1GT, 1M Aux. Trans. & Substat. Lockout Misc. Trip - Unit 1 [Interlock Logic Diagram for Main Generator 1GT, IM Auxiliary Transformer & Substation Lockout Miscellaneous Trip - Unit 1]," Revision D.

The inspectors verified that the frequency output from the main generator was not used to provide any safety-related functions but rather was used to provide control and remote indicating functions only. The frequency meters on the main control boards were also found to be within acceptable calibration tolerance limits associated with TP 1828 and TP 2828. The inspectors brought the frequency meter difference to the attention of the Unit 1 and 2 shift supervisors and the Unit 1 lead reactor operator who stated that slight differences between frequency meter readings were normal and the result of calibration differences.

- With the exception of the Unit 1 power reduction and ascension (Section O1.2), this inspection period was characterized by routine operations with no significant operator challenges. Throughout the inspection period, the inspectors evaluated control room personnel on their awareness of plant equipment status. When asked specific questions, operators correctly stated what the equipment status, associated problem(s) and corrective actions, and anticipated return to service times were.

c. Conclusions

The inspection period was characterized by routine operations. When questioned by the inspectors, control room personnel displayed adequate knowledge of equipment problems and status.

O1.2 Unit 1 Power Reduction and Ascension

a. Inspection Scope (IP 71707)

The inspectors observed control room activities during the Unit 1 power reduction to about 40 percent on August 1-2, 1998. The power reduction was performed to support replacement of a leaking manway gasket on the Unit 1 condenser.

b. Observations and Findings

The reactor power decrease was performed in an efficient and controlled manner. The inspectors observed that the reactor operator closely controlled reactivity with control rods and boron addition while remaining attentive to average reactor coolant temperature, axial flux difference, reactor power, and Xenon effects. Lessons learned from a prior power reduction in which the axial flux difference deviated from the target band were evident.

Close supervisory oversight was maintained throughout the evolution, with an extra shift supervisor assigned to focus primarily on the power reduction. Control rod position indication deviations from the bank positions occurred occasionally and in each case, operators reviewed core thermocouple data to verify that the rods were not actually mispositioned. The desired power level was reached without any significant problems.

c. Conclusions

The planned power reduction on Unit 1 was conducted in a controlled and deliberate manner, with good control of core reactivity and effective supervisory oversight.

O.2 Operational Status of Facilities and Equipment

O2.1 Safeguards Station Battery Inspection

a. Inspection Scope (IP 71707)

Safeguards station batteries were chosen for inspection based on the inspector's review of the licensee's Probabilistic Risk Analysis, as contained in the Prairie Island Individual Plant Examination Report, "NSPLMI-94001," Revision 0, which identified that the loss of direct current (DC) power was an initiating event which impacted Core Damage Frequency (CDF). The inspectors examined the physical condition and installation of the 11, 12, 21, and 22 safeguards station batteries. The inspectors also compared Technical Specification (TS) requirements, vendor technical manual recommendations, and the Institute of Electrical and Electronic Engineers (IEEE) standard practices for maintenance and testing with what was contained in the battery surveillance procedures. Also, the inspectors compared the battery installation to the as-built vendor drawings. During the performance of this inspection, the inspectors reviewed the references and surveillance procedures (SP) listed below.

- SP 1187, "Weekly Battery Inspection," Revision 11;
- SP 1323, "11 Battery Monthly Inspection," Revision 3;
- SP 1324, "12 Battery Monthly Inspection," Revision 3;
- SP 2323, "21 Battery Monthly Inspection," Revision 3;
- SP 2324, "22 Battery Monthly Inspection," Revision 3;
- SP 1325, "11 Battery Quarterly Inspection," Revision 3;
- SP 1326, "12 Battery Quarterly Inspection," Revision 3;
- SP 2325, "21 Battery Quarterly Inspection," Revision 3;
- SP 2326, "22 Battery Quarterly Inspection," Revision 3;
- SP 1337, "11 Battery Semi-Annual Inspection," Revision 3;
- SP 1336, "12 Battery Semi-Annual Inspection," Revision 3;
- SP 2337, "21 Battery Semi-Annual Inspection," Revision 3;

- SP 2336, "22 Battery Semi-Annual Inspection," Revision 4;
- SP 1098, "11 Battery Refueling Outage Discharge Test," Revision 18;
- SP 1314, "12 Battery Refueling Outage Discharge Test," Revision 5;
- SP 2098, "21 Station Battery Refueling Outage Discharge Test," Revision 17;
- SP 2314, "22 Station Battery Refueling Outage Discharge Test," Revision 4;
- IEEE Standard 450-1995, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications"; and
- Technical Manual XH-271-5, "Batteries and Racks."

b. Observations and Findings

The inspectors performed a visual inspection of the 11, 12, 21, and 22 station batteries. The inspectors noted that the physical condition of the battery casings was good, cell water levels were correct, areas around the batteries were free from debris, flame arresters were in place, terminal connectors and lugs appeared tight and relatively clean, and the precautions for working on and around the batteries were well posted. The inspectors noted a crystalline residue around the top edge of the battery jars on the 12 and 22 station batteries. The inspectors discussed this with the Superintendent of Electrical Systems Engineering. He stated that it appeared to be battery acid residue and that the residue would be removed and the cause of the residue build-up would be investigated.

Based on review of applicable documentation, the inspectors determined that the licensee adequately incorporated TS requirements and IEEE and battery vendor recommendations into the various battery surveillance procedures. In most cases, the testing performed per the battery surveillance procedures, whether it required more individual battery cells to be monitored for a given parameter or increased the periodicity of an analysis, exceeded what was recommended by the battery vendor and the IEEE.

The inspectors discussed with the Superintendent of Electrical Systems Engineering how the battery data obtained from the surveillance procedures was used to trend individual cell and overall battery performance. He demonstrated to the inspectors how the programs and databases, which utilized parameters obtained during the performance of the station battery surveillance program, were used to trend important battery information such as cell specific gravity, cell electrolyte temperature, battery float voltage, individual cell voltages, and inter-cell connector resistance.

The inspectors reviewed the as-built vendor installation schematics for the 11, 12, 21, and 22 station batteries and battery racks and compared them to what was actually present in the battery rooms. The inspectors noted no installation discrepancies.

c. Conclusions

The material condition of the 11, 12, 21, and 22 station batteries was good. The surveillance and maintenance procedures for the batteries incorporated TS requirements and included IEEE and battery vendor maintenance and testing recommendations. The licensee maintained a database of information for each station battery and effectively utilized the information in tracking and trending battery performance.

O2.2 Review of Licensee Year 2000 (Y2K) Readiness Project Management Plan

a. Inspection Scope (IPs 71707, 37551)

The inspectors reviewed the licensee's Year 2000 Readiness Project Management Plan. The inspection focused on whether the plan incorporated actions to address the Y2K concerns as described in Generic Letter 98-01. Documents reviewed as part of this inspection are listed below.

- NRC Generic Letter 98-01, "Year 2000 Readiness of Computer Systems at Nuclear Power Plants";
- Prairie Island Nuclear Generating Plant Year 2000 Readiness Project, Project Management Plan, Revision 0; and
- NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness."

b. Observations and Findings

The inspectors concluded that the Y2K readiness plan clearly defined the project goals, scope of work, major project milestones, the make-up of the project team and their responsibilities, and the project control and administration. The project's goals included; Y2K problem awareness and communication, discovery, prioritization and classification, detailed assessment, remediation, testing and validation, contingency planning and risk management, and documentation. The plan used risk assessment to define high risk systems and offsite connections. The inspectors interviewed the Prairie Island Y2K program manager. The program manager was responsible for preparing a monthly project status report for NSP Management. Based on discussions with the program manager, the inspectors were informed that currently the project team was in the process of identifying Y2K issues to be addressed in the next Unit 2 refueling outage (Cycle 19) and was continuing work on the "Detailed Assessment" phase of the management plan.

c. Conclusions

The licensee was implementing a comprehensive Year 2000 Readiness Management plan to address the computer readiness issues discussed in NRC Generic Letter 98-01.

O7 Quality Assurance in Operations

O7.1 Licensee Organizational Changes

The licensee announced two organizational changes effective August 31, 1998.

- Dick Lindsey, formerly the General Superintendent for Safety Assessment, filled the new position of Site Alliance Implementation Manager. This new position was created to address issues raised during the formation of alliances between Prairie Island and other nuclear sites.

- Jim Hill, formerly the Quality Services Manager, filled the new position of Nuclear Performance Assessment Manager. This new site organization combined the Safety Assessment and Generation Quality Services organizations with the goal of better integration of assessment activities.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (IPs 61726, 62707)

The inspectors observed all or portions of the maintenance and surveillance test activities described in the listed procedures. Included in the inspection was a review of the surveillance procedures (SP), preventive maintenance procedures (PM), or work orders (WO) listed as well as the appropriate USAR sections regarding the activities. The inspectors verified that the surveillance procedures met the applicable TS requirements.

- SP 1074, "Auxiliary Building Special Vent System Functional Test," Revision 23;

- SP 1093, "D1 Diesel Generator Slow Start Test," Revision 67;

- SP 1305, "D2 Diesel Generator Slow Start Test," Revision 17;

- SP 1319, "Rod Position Verification," Revision 6;

- PM 3001-3-D1, "D1 Diesel Generator Bearing Insulation Check," Revision 4;

- WO 9809902, "Inspect/Replace 12 CC HX TCV [Component Cooling Heat Exchanger Temperature Control Valve] Positioner Pilot/Plug";

- WO 9809902, "Conduct EROC/MIC [Erosion Control/Micro biologically Influenced Corrosion] Exam on CL/ZX [Cooling Water/Chilled Water] Piping Inspection";

- SP 1100, "12 Motor Driven AFW [Auxiliary Feedwater Pump] Pump Monthly Test," Revision 53;

- SP 1081.2, "122 Aux Building Special Ventilation Filter Removal Efficiency Test," Revision 7; and

- SP 2258B, "Bus 26 Sequencer Load Rejection and Restoration of 122 CR [Control Room] Chiller," Revision 1.

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

- The inspectors attended the pre-job briefing and witnessed testing being performed in accordance with Surveillance Procedure SP 1074 on August 10, 1998. This surveillance test was of interest since two doors in the auxiliary building special ventilation boundary zone (doors 155 and 177) had recently been locked in the open position due to flooding concerns in the Unit 1 loop "A" main steam isolation valve room (Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section O2.1). The inspectors were interested in determining if the auxiliary building special ventilation (ABSV) system was still capable of achieving TS negative pressure requirements with doors 155 and 177 being open.

  The pre-job briefing was adequate and discussed the location of the opening in the ABSV zone boundary, monitoring of local dampers, communications, operator assignments, and the temporary change notice associated with the test procedure and special controls associated with Doors 155 and 177. The surveillance test (SP 1074) was performed satisfactorily and the ABSV system was proven to be capable of achieving the TS required negative pressure in the auxiliary building.

- The inspectors observed activities associated with WO 9809902, and discussed the progress of the work with contract nondestructive test examiners and the chilled water system/erosion control system engineer. The inspectors learned that localized portions of the chilled water system had experienced wall loss of as much as 60 percent of the nominal wall thickness. The chilled water system is a nonsafety-related system and is one of two available supplies to the Unit 1 and Unit 2 containment fan coil units (FCUs). The second supply to the containment FCUs in Unit 1 and Unit 2 is provided by the safety-related cooling water system. Containment fan coil units are needed to remove heat from the containment atmosphere during a design basis accident to minimize the peak pressures experienced in containment.

  The inspectors reviewed available nondestructive examination results with the system engineer and learned that no portions of the safety-related cooling water piping to or from the containment FCUs had experienced wall loss. This was due, in part, to the fact that a continuous flow of water is maintained in the cooling water system whereas portions of the chilled water system are stagnant for prolonged periods of time. Also, the cooling water system was treated with a biocide to reduce the potential of microbiological influenced corrosion (MIC) whereas the chilled water system was not treated. The inspectors verified that, to date, the safety-related portions of the containment FCUs have been unaffected by the mechanism causing the wall loss in the chilled water piping.

- The inspectors observed testing being performed in accordance with Test Procedure SP 1100, "12 Motor Driven AFW Pump Monthly Test," Revision 53. The inspectors observed portions of the test from the control room, as well as locally in the vicinity of the 12 AFW pump. The inspectors noted that adequate coordination and communication were demonstrated between the operators in the control room and operators in the auxiliary feed pump room. The inspectors also observed that the motor-operated valves and control valves tested in accordance with this surveillance procedure operated smoothly and that the stroke times were within their acceptable time ranges. The auxiliary feed pump was started remotely from the control room, generated the required differential pressure, and operated normally throughout the performance of the surveillance test.

- The inspectors attended the pre-evolution briefing and observed testing being performed in accordance with Test Procedure SP 1305, "D2 Diesel Generator Slow Start Test," Revision 17. The operability of the D2 diesel generator came into question when, during the restoration portion of the D1 diesel generator's 18-month inspection, stem-disc separation (discussed in Section M1.2) was discovered in the D1 generator's cooling water outlet isolation valve. Operability of the D2 diesel generator was verified by performing a test in accordance with SP 1305. Due to the fact that the D1 diesel generator was already inoperable, making the D2 EDG inoperable to perform a test per SP1305, required entry into a very time restrictive TS limiting condition for operation (LCO). The inspectors noted that good communication and planning by the control room operators and auxiliary operators contributed to the successful completion of the applicable surveillance tests and the timely restoration of the diesel generator to operation.

c. Conclusions

All the routine maintenance activities and surveillance tests observed by the inspectors were conducted well, and the licensee used safe work practices and demonstrated good communication and coordination between the control room and workers performing the work/tests.

M1.2 D1 Diesel Generator 18-Month Planned Maintenance

a. Inspection Scope (IP 62707)

The inspectors reviewed the activities associated with the D1 diesel generator planned maintenance outage. The inspectors reviewed applicable procedures and electrical and mechanical isolation documentation. In addition, the inspectors observed personnel performing the maintenance work. Documents reviewed as part of this inspection are listed below.

- PM 3001-4-D1, "D1 Diesel Generator Inspection-Electrical," Revision 3;

- PM 3001-2-D1, "D1 Diesel Generator 18-Month Inspection," Revision 14;
- WO 9810236, "D1 Diesel Generator Run-In (Shortened Version)," Revision 1; and
- WO 9810603, "D1 Cooling Water Discharge Valve Repair."

b. Observations and Findings

Technical Specification 4.6.A.3.a required the licensee to subject each diesel generator to a thorough inspection in accordance with procedures prepared in consideration of the manufacturer's recommendations. This requirement was met by performing preventative maintenance (PM) per Procedures PM 3001-4-D1 and PM 3001-2-D1. The inspectors reviewed the TS LCO requirements, procedural documentation, and work practices at many stages throughout the D1 diesel generator outage. The inspectors also attended a number of pre-evolution and maintenance update briefings.

During the diesel generator inspection, the inspectors were informed that some scoring had been discovered on the thrust bearing and that the bearing was being replaced. The inspectors examined the bearing and noted the slight scoring on the face of the journal portion of the bearing. The system engineer told the inspectors that this type of scoring was not uncommon in diesel engines that are subjected to cold fast starts and that, even though the scoring on the bearing did not make the diesel generator inoperable, the conservative action was taken and the bearing was replaced.

After the completion of the planned maintenance activity, the D1 diesel was run per the D1 Diesel Generator Run-In procedure. During this procedure, at approximately 700 revolutions per minute with the generator unloaded, cooling water outlet and lube oil temperatures increased to a point that required the shutting down of the diesel generator. An investigation was performed and the licensee determined that when the cooling water outlet isolation valve was repositioned to its normally open position following the completion of maintenance, stem-disc separation occurred leaving the disc in the valve seat.

The inspectors evaluated the licensee corrective actions. These actions included isolating and draining portions of the Train A cooling water return header, replacing the cooling water isolation valve stem, disc, and bushing, and performing an operability verification for the D2 diesel generator. The inspectors examined the disc and stem that had been removed from the cooling water isolation valve. There were corrosion products on the disc and disc wedge and it appeared that the boss edges (the "ears") on the disc wedge had corroded to a degree where they no longer coupled with the disc. The system engineer classified the failure mechanism of the valve as normal general corrosion. The licensee initiated Condition Report 1998-2052 to document the valve failure and track corrective actions. Following the valve repair, the D1 Diesel Generator Run-In procedure and the D1 Diesel Generator 18-Month inspection procedures were completed without any further difficulties.

The inspectors observed that system engineers, especially the D1 and D2 diesel generator system engineers, demonstrated ownership of their systems by providing pertinent technical information during many briefings, and by assisting in the coordination of activities at the work site.

c. Conclusions

Throughout the D1 diesel generator outage, good coordination was demonstrated between operations, engineering, maintenance, and instrumentation and control personnel. This was especially evident when operability of the D2 diesel generator was being verified, which required entry into a very time restrictive LCO, and during the cooling water outlet isolation valve repair effort, which required close coordination between operations and maintenance personnel to set up the proper system conditions required for the valve repair.

M1.3 Procedural Adherence During Performance of 12 Shield Building Ventilation Filter Removal Efficiency Test

a. Inspection Scope (IPs 61726, 62707)

The inspectors observed portions of the maintenance and surveillance test activities associated with SP 1080.2, "12 Shield Building Ventilation Filter Removal Efficiency Test," Revision 8, on September 1, 1998.

b. Observations and Findings

In accordance with WO 9806299, maintenance personnel were required to remove and replace one charcoal filter tray from the 12 shield building ventilation system (SBVS) filter train and then test the charcoal filter efficiency in accordance with SP 1080.2. While observing the removal and installation of the charcoal filter tray, the inspectors noticed that only the downstream door of the charcoal filter bank had been opened for maintenance personnel access. The 12 SBVS has two access doors in the vicinity of the charcoal filter bank, one allowing upstream charcoal filter access and one allowing downstream charcoal filter access.

Step 7.5 of SP 1080.2 specifically required unlocking and opening of both the upstream and downstream doors for the 12 SBVS. Step 8.6 directed maintenance personnel to perform a visual examination of the reinstalled charcoal filter tray for leaks by shining a light on the downstream side of the trays while a second person looked for visible light in the darkened, upstream compartment.

The inspectors observed that the upstream charcoal filter tray access door was never opened as required by Step 7.5 and Step 8.6. Instead, the cubicle overhead light on the upstream side of the charcoal filter housing was turned on and the visual examination for leaks was performed by looking in the upstream direction from the downstream side of the charcoal filter trays. The inspectors brought this discrepancy to the attention of the two maintenance workers performing the surveillance test per SP 1080.2. Both stated that the upstream filter door had not been opened and remained closed during the filter tray replacement. The inspectors also interviewed a health physics technician who performed a contamination survey on the downstream side of the charcoal filter prior to the maintenance workers entering the 12 SBVS enclosure. The health physics technician stated that he had only unlocked the downstream charcoal filter assembly door and did not unlock or survey the door and enclosure associated with the upstream side of the charcoal filter. The inspectors provided the Unit 1 shift supervisor with their procedural adherence observation. The Unit 1 shift supervisor stopped work on SP 1180.2 and contacted the system engineer. The inspectors also discussed the observation with the maintenance workers' supervisor.

The system engineer subsequently wrote a temporary change notice (TCN 1998-0084) which deleted Step 8.6 from SP 1180.2. The system engineer presented this change notice to the Operations Committee for review on the same afternoon of the inspector's observation. Deleting Step 8.6 was acceptable since subsequent steps in SP 1180.2 directed the performance of a SBVS Freon efficiency test. Presumably, if any charcoal filter leakage existed, the Freon test would fail. The system engineer explained that the purpose of the visual test in Step 8.6 was one of time efficiency. If a large filter sealing gap was observed with the light inspection conducted in Step 8.6, this early leak detection would allow for correction of the situation before clearing isolation tags, running the entire system, and failure of the Freon test. The inspectors subsequently observed the successful performance of the 12 SBVS Freon test during the afternoon of September 1, 1998.

Since a Freon test for charcoal filter efficiency followed the visual test of Step 8.6 and the Freon test was satisfactory, the safety significance of incorrectly performing the visual examination was minor. Also, the operations committee recommended prompt and adequate corrective action for the maintenance workers involved with SP 1180.2. These actions included:

- holding just-in-time training on September 2, 1998, for maintenance and health physics department personnel to emphasize management expectations concerning procedural compliance and the need to follow the established procedure change processes;

- having the cognizant maintenance supervisor counsel the two maintenance workers involved; and

- initiating an Error Reduction Task Force examination of the event.

Technical Specification Section 6.5.C.1 requires, in part, that detailed written procedures be prepared and followed for equipment required in the TSs. The shield building ventilation system is equipment required in TS Section 3.6.H. Thus, failure to follow SP 1080.2, "12 Shield Building Ventilation Filter Removal Efficiency Test," Revision 8, Steps 7.5 and 8.6, constituted a violation since written procedures applying to equipment described in the facility TSs were not followed (50-282/98015-01(DRP)).

The inspectors noted that the licensee had taken considerable corrective actions in the last year to address procedure quality and adherence problems. Taken on a broad basis, these have been successful and have been discussed in Inspection Report 50-282/98005(DRP); 50-306/98005(DRP), Section O8.2, and the Systematic Assessment of Licensee Performance Report 50-282/98001; 50-306/98001, Section II.A., Plant Operations. Plant management had described procedure quality and adherence corrective actions to the NRC during management meetings held on May 20 and November 25, 1997. Licensee procedure quality and corrective actions presented during these meetings were docketed in the enclosure to a letter from the NRC, Region III, Division of Reactor Projects, Chief, Reactors Projects Branch 7, to Mr. M. Wadley, Vice President, Nuclear Generation, Northern States Power Company dated December 22, 1997.

c. Conclusion

The inspectors identified that maintenance personnel did not perform a charcoal filter tray removal and replacement work activity in accordance with applicable procedures in violation of TS requirements. Specifically, maintenance personnel failed to follow the surveillance procedure as written, implement the temporary change procedure process, and inform supervision that they had deviated from the surveillance procedure. Considerable management attention and focus had been placed on procedure quality, adherence, and compliance over the last several months. Overall, these procedure quality and adherence improvement initiatives have been effective in improving overall performance in these areas.

M3 Maintenance Procedures and Documentation

M3.1 Failure to Adequately Test the Reactor Coolant Vent System as Required by TSs

a. Inspection Scope (IPs 61726, 62707)

On July 31, 1998, the licensee identified that the reactor coolant vent system was not being tested as required by TSs. The inspectors reviewed the background information, surveillance procedures, operating procedures, and TS pertaining to vent path operability and system flow testing requirements used to demonstrate reactor coolant vent system operability. During the performance of the inspection, the inspectors utilized the reference material listed below.

- Technical Specification 4.18, "Reactor Coolant Vent Paths," Revision 91;
- WO 9810381, "Flow Test RCGVS [Reactor Coolant Gas Vent System] Tailpipe to Containment and PRT";
- WO 9810382, "Flow Test RCGVS Tailpipe to Containment and PRT";
- SP 1248, "Cycling RCS [Reactor Coolant System] Gas Vent Solenoid Valves Unit 1," Revision 9;
- SP 2248, "Cycling RCS Gas Vent System Solenoid Valves Unit 2," Revision 7;
- OP [Operating Procedure] 1D8, "Filling and Venting the Reactor Coolant System," Revision 11; and
- OP 2D8, "Filling and Venting the Reactor Coolant System," Revision 7.

b. Observations and Findings

In accordance with TS 4.18.A.2, the reactor coolant vent system operability was verified, in part, by "cycling each solenoid operated valve in the vent path through at least one complete cycle of full travel from the control room" and was performed "prior to commencing STARTUP OPERATION after each refueling." During a review of the work completed during the last Unit 1 refueling outage, the system engineer responsible for the reactor coolant vent system discovered that the solenoid valves had been cycled at the beginning of the refueling outage instead of after refueling, as required by the TS. Further investigation by the system engineer revealed that during previous refueling outages for both Unit 1 and Unit 2, the solenoid valves were routinely cycled at the beginning of the outage instead of after the completion of refueling operations. The system engineer said that the advantage of performing the surveillance test that cycles the solenoid valves at the beginning of the outage, instead of after refueling, was that if performance of testing in accordance with the surveillance procedure revealed that maintenance was required on the solenoid valves, plant startup would not be delayed.

The inspectors discussed the corrective actions taken by the licensee with the Superintendent of Mechanical Systems Program Engineering. He said that a license amendment request was prepared to clarify the intent of the TS. The license amendment requested, in part, that the words "after each refueling" be changed to "every refueling cycle" to allow for testing of the solenoid valves at any time during the refueling outage. The inspectors concluded that since the vent path operability had been verified at the beginning of each refueling outage, vice after the refueling outage as required by TS 4.18.A.2, the licensee's actions violated the TSs. This non-repetitive, licensee-identified and corrected violation, is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-282/98015-02(DRP); 50-306/98015-02(DRP)).

The inspectors were informed by the licensee that while researching surveillance and operating procedures, during the process of preparing a Licensee Event Report (LER) (LER 50-282/98015; 50-306/98015 (1-98-09)) to document the RCS vent solenoid valve issue, the system engineer discovered that portions of the RCS vent system were not being tested for system flow, as required by TS 4.18.B. The system engineer informed the inspectors that, in the past, system flow was verified by tests performed in accordance with OP 1D8 (OP 2D8) and SP 1248 (SP 2248), for Unit 1 and Unit 2 respectively. Further system analysis revealed that two portions of piping, downstream of the piping tee that branches to RC-14-2 and to containment atmosphere and downstream of the piping tee that branches to RC-14-1 and to the pressurizer relief tank (PRT), were not tested by those procedures. Licensee Event Report 50-282/98015; 50-306/98015 (1-98-09) is considered open pending the inspectors' review of the licensee's corrective actions.

The inspectors noted that the licensee, once it had determined that portions of the RCS vent system had not been tested for Unit 1 and Unit 2, conservatively declared both RCS vent systems inoperable and entered the applicable LCOs. Subsequent to declaring the RCS vent systems inoperable, special test procedures were prepared and followed to verify flow capabilities in the affected piping. These tests were conducted at power and completed with satisfactory results. The inspectors discussed with the

Superintendent of Mechanical Systems Program Engineering additional corrective actions that were taken to address this problem. The superintendent said that Surveillance Procedures SP 1248 and 2248 were being modified to ensure that the affected piping would be flow tested and that the RCS filling and venting procedures, 1D8 and 2D8, were being modified to reflect that portions of those procedures would be used to verify acceptance criteria for RCS vent system flow testing. The inspectors concluded that the licensee had not adequately flow tested the RCS vent system paths which constituted a violation of TS 4.18.B. The inspectors considered this violation to be non-repetitive, licensee-identified and corrected and the violation is therefore being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-282/98015-03(DRP); 50-306/98015-03(DRP)).

c. Conclusions

Through a good questioning attitude, the licensee's system engineers identified two issues with the RCS vent system. Once identified, the licensee took conservative and timely action to address each issue.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of USAR Commitments (IPs 37551, 92903)

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected and used the USAR as an engineering/technical support basis document. The inspectors compared plant practices, procedures, and/or parameters to the USAR descriptions as discussed in each section. The inspectors verified that the USAR wording was consistent with the observed plant practices, procedures, and parameters. No discrepancies were noted.

E2.2 System Engineer Ownership of Plant Systems

System engineers continued to demonstrate ownership of their respective systems. Specific examples of this were cited in Sections O2.1, M1.2, and M3.1 of this report. The detailed system knowledge possessed by these engineers routinely aided in the successful briefing, coordination, and completion of many surveillance procedures and maintenance activities.

E3 Engineering Procedures and Documentation

E3.1 Reactor Vessel Head Weight Used in Heavy Loads License Documentation May Be in Error

a. Inspection Scope (IPs 37551, 92903)

The inspectors reviewed the available documentation and action plans associated with a licensee-identified finding regarding the weight of the reactor vessel head used in load drop calculations during refueling operations.

b. Observations and Findings

As part of the USAR and heavy loads documentation long-term update projects, the licensee reviewed design basis documents and USAR load weights associated with the reactor vessel head. The licensee identified that USAR Section 12.2.12, "Control of Heavy Loads," Table 12.2-40, "Loads Handled Over Safety Related Components, Components Required for Plant Shutdown, or Decay Heat Removal," Revision 14, listed the reactor vessel head weight as 80,925 pounds. The actual weight of the reactor vessel head including studs, nuts, control rod drive mechanisms, rod position indication coil stacks, cooling shrouds, and dummy cans is approximately 176,000 pounds.

A letter from Northern States Power to the Director, Office of Nuclear Reactor Regulation, dated December 9, 1981, described the analysis performed to demonstrate compliance with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants - Resolution of TAP A-36," Appendix A, for the case of an accidental drop of the reactor vessel head onto the reactor vessel. This analysis showed that for the accidental drop of the reactor vessel head onto the reactor vessel in a dry refueling cavity, the reactor coolant loops may crack while the safety injection lines to the reactor vessel would deflect 0.55 inches but remain intact. With the safety injection lines still intact, adequate cooling could still be provided to the nuclear fuel in the reactor vessel preventing loss of inventory due to boiling and subsequent fuel damage. The licensee, however, was not able to determine what reactor vessel head weight was used in this load drop analysis.

Uncertain of the weight used in the reactor vessel head drop calculation and in accordance with 10 CFR 50.9, the licensee conservatively notified the NRC Region III staff on August 11 and 12, 1998, of a case where information supplied to the NRC may not have been complete and accurate in all material respects. In addition, the licensee was in the process of re-performing the reactor vessel head drop calculations using a reactor vessel head weight of 186,900 pounds. The 186,900 pounds includes the weight of the reactor vessel head, its normal attachments, lifting rigs and platforms, and stud tensioner hoists. The licensee expected to complete the calculations by October 15, 1998.

The results of the calculations could potentially impact an upcoming Unit 2 refueling outage scheduled to begin on November 7, 1998. If the load drop calculations using 186,900 pounds are not bounded by the results of the 1981 calculations or show that both the safety injection and reactor coolant lines may crack during a refueling cavity load drop scenario, then the ability to maintain an inventory supply to the nuclear fuel could be compromised.

This issue is considered an Unresolved Item pending inspector review of reactor vessel load drop calculations using 186,900 pounds as the weight of the reactor vessel head and associated attachments (50-282/98015-04(DRP); 50-306/98015-04(DRP)). The inspectors will review the completed load drop calculations to determine if a violation of 10 CFR 50.9 requirements had occurred and for potential impact on the upcoming Unit 2 refueling outage.

c. Conclusions

During a review of the USAR and heavy load documents, the licensee was unable to confirm the weight of the reactor vessel head used in NUREG-0612 load drop calculations. This finding resulted from a good questioning attitude by engineering personnel and demonstrated the comprehensive nature of the ongoing USAR update project. Actions are being taken to perform a load drop analysis using the appropriate reactor vessel head weight.

E8 Miscellaneous Engineering Issues (IP 92903)

E8.1 (Closed) LER 50-282/98005, Supplement 1 (1-98-05-01): Inoperability of Actuation Logic for Main Steam Isolation Valves in Certain Flooding Conditions from a Feedwater Line Break. The licensee issued this supplement to describe an additional concern with flooding in the area of the main steam isolation valves on Unit 2. The issue was also discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section O2.1.

On August 3, 1998, the licensee retracted Supplement 1 based on engineering calculations that demonstrated that the area of concern would not flood. As discussed in Inspection Report 50-282/98009(DRP); 50-306/98009(DRP), Section E8.1, the inspectors reviewed the applicable calculations and had no concerns.

The original LER 50-282/98005 (1-98-05-00) remains open pending completion of the corrective actions described therein.

IV. Plant Support

F2 Status of Fire Protection Facilities and Equipment

F2.1 Fire Protection Functional Inspection

During the weeks of August 10-14, and August 24-28, 1998, the NRC conducted a Fire Protection Functional Inspection at Prairie Island. The inspection team members consisted of two inspectors from the NRC Region III office, one inspector from the NRC Office of Nuclear Reactor Regulation, and two inspectors from Brookhaven National Laboratory. The focus of the inspection was to review the results of the licensee's fire protection self-assessment and to perform independent reviews, as necessary, to validate the licensee's conclusions and evaluate licensee corrective actions for identified issues. Specific information concerning this inspection was documented in Inspection Report 50-282/98016(DRS); 50-306/98016(DRS).

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 10, 1998. 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

J. Sorensen, Plant Manager
K. Albrecht, General Superintendent Engineering, Electrical/Instrumentation & Controls
T. Amundson, General Superintendent Engineering, Mechanical
J. Goldsmith, General Superintendent Engineering, Generation Services
J. Hill, Nuclear Performance Assessment Manager
G. Lenertz, General Superintendent Plant Maintenance
R. Lindsey, Site Alliance Implementation Manager
D. Schuelke, General Superintendent Radiation Protection and Chemistry
T. Silverberg, General Superintendent Plant Operations
M. Sleigh, Superintendent Security

INSPECTION PROCEDURES USED

IP 37551:	Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750	Plant Support Activities
IP 92700:	Onsite Follow-up of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92901:	Follow up - Operations
IP 92902:	Follow up - Maintenance
IP 92903:	Follow up - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/98015-01(DRP)	VIO	Procedure Adherence During the Performance of 12 Shield Building Ventilation Filter Removal Efficiency Test
50-282/98015-02(DRP) 50-306/98015-02(DRP)	NCV	Failure to Perform Reactor Vent Path Operability Tests After Each Refueling Outage
50-282/98015-03(DRP) 50-306/98015-03(DRP)	NCV	Failure to Adequately Test the Reactor Coolant Vent System as Required by TSs
50-282/98015-04(DRP) 50-306/98015-04(DRP)	URI	Reactor Vessel Head Weight Used in Heavy Loads License Documentation May Be In Error
50-282/98015 (1-98-09) 50-306/98015	LER	Reactor Coolant Vent System Testing

Closed

50-282/98005, Supplement 1 (1-98-05-01)	LER	Inoperability of Actuation Logic for Main Steam Isolation Valves in Certain Flooding Conditions from a Feedwater Line Break
50-282/98015-01(DRP)	VIO	Procedure Adherence During the Performance of 12 Shield Building Ventilation Filter Removal Efficiency Test
50-282/98015-02(DRP) 50-306/98015-02(DRP)	NCV	Failure to Perform Reactor Vent Path Operability Tests After Each Refueling Outage
50-282/98015-03(DRP) 50-306/98015-03(DRP)	NCV	Failure to Adequately Test the Reactor Coolant Vent System as Required by TSS

Discussed

50-282/98005 (1-98-05-00)	LER	Inoperability of Actuation Logic for Main Steam Isolation Valves in Certain Flooding Conditions from a Feedwater Line Break

LIST OF ACRONYMS USED

ABSV	Auxiliary Building Special Ventilation
AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
DC	Direct Current
DRP	Division of Reactor Projects
EA	Enforcement Action
EDG	Emergency Diesel Generator
FCU	Fan Coil Unit
IP	Inspection Procedure
IEEE	Institute of Electrical and Electronics Engineers
LER	Licensee Event Report
LCO	Limiting Condition for Operation
MCA	Maximum Credible Accident
MIC	Microbiological Influenced Corrosion
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
OP	Operating Procedure
PDR	Public Document Room
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
RCGVS	Reactor Coolant Gas Vent System
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SAC	Safety Audit Committee
SP	Surveillance Procedure
TBO	Turbine Building Operator
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order
Y2K	Year 2000