May 28, 2000

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

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/2000005(DRP); 50-306/2000005(DRP)

Dear Mr. Wadley:

On April 2 through May 18, 2000, the NRC completed a safety inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection. The results were discussed on May 18, 2000, with Mr. D. Schuelke and other members of your staff.

The inspection was an examination by the resident inspectors of activities conducted under your license as they relate to reactor safety, verification of performance indicators, event followup, human performance, and to 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. Temporary Instruction 2515/142, "Draindown During Shutdown and Common-Mode Failure (NRC Generic Letter 98-02) was also completed by a regional project engineer during this inspection.

Based on the results of this inspection, one potentially risk significant issue was identified with an apparent violation of your Technical Specifications due to the improper implementation of a steam generator nozzle dam installation procedure. The issue has been entered into your corrective action program and is discussed in the summary of findings and in the body of the enclosed report. The NRC will inform you of its final determination of the significance of the condition and any associated enforcement action following additional assessment by NRC risk analysts.

The NRC also evaluated an additional issue under the risk significance determination process and determined it to be of very low risk significance (Green). That issue has been entered into your corrective action program and is discussed in the summary of findings and in the body of the enclosed report. The issue was determined to involve a violation of NRC fire protection requirements, but because of its very low safety significance, the violation was not cited. In addition, the NRC evaluated several issues in the cross-cutting area of human performance dealing with implementation of safety tagging procedures. The issues have all been entered into your corrective action program and are discussed in the summary of findings and in the body of the enclosed report. The safety tagging issues were considered a finding with no risk significance assigned.

If you contest the non-cited violation, 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 placed in the NRC Public Document Room and is available on the NRC Public Electronic Reading Room (PERR) link at the NRC homepage, http://www.nrc.gov/NRC/ADAMS/index.html.

Sincerely,

Original signed by
Roger Lanksbury, Chief

Roger Lanksbury, Chief
Reactor Projects Branch 5

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

Enclosure: Inspection Report 50-282/2000005(DRP);
50-306/2000005(DRP)

cc w/encl: Site General Manager, Prairie Island
Plant Manager, Prairie Island
S. Minn, Commissioner, Minnesota
Department of Public Service
State Liaison Officer, State of Wisconsin
Tribal Council, Prairie Island Dakota Community

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REGION III

Docket Nos:	50-282, 50-306
License Nos:	DPR-42, DPR-60
Report No:	50-282/2000005(DRP); 50-306/2000005(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	April 2, 2000 through May 18, 2000
Inspectors:	S. Ray, Senior Resident Inspector S. Thomas, Resident Inspector M. Kunowski, Project Engineer
Approved by:	Roger Lanksbury, Chief Reactor Projects Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

Prairie Island Nuclear Generating Plant, Units 1 & 2
NRC Inspection Report 50-282/2000005(DRP); 50-306/2000005(DRP)

The report covers a 6½-week period of resident inspection.

The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process in Inspection Manual Chapter 0609.

Cornerstone: Mitigating Systems

- TO BE DETERMINED. The licensee identified that maintenance technicians had installed a steam generator primary bowl drain plug in the wrong hole while installing steam generator nozzle dams at reduced reactor coolant inventory on Unit 2. The error was discovered while refilling the reactor coolant system when water was noted spilling out of a steam generator manway. To correct the error, the licensee needed to redrain the system and reenter the steam generators to install the plug. This resulted in spending over 7 additional hours beyond the 50 hours that had already been spent at reduced reactor coolant inventory conditions.

  Using the Significance Determination Process of Inspection Manual Chapter 0609, Appendix G, the inspectors determined that the finding was potentially risk significant and required further quantitative assessment by NRC risk analysts. The issue was determined to be an Apparent Violation (AV) for failure to properly implement procedures required by Technical Specifications. The tracking number for this AV is 50-306/2000005-01(DRP). The finding was assigned to Unit 2. (Section 1R20)

- GREEN. The licensee determined that electrical cables on redundant trains of pressurizer power operated relief valves and block valves in the Unit 2 containment were not separated by at least 20 feet as required by an exemption to 10 CFR Part 50, Appendix R. In the case of spurious valve opening due to hot shorts, reactor coolant system pressure control could have been lost and the ability to maintain natural circulation cooling following a fire in the containment could have been adversely affected.

  Using the Significance Determination Process of Inspection Manual Chapter 0609, Appendix F, NRC fire protection specialists determined that the issue was of very low risk significance and within the licensee control band since the probability of a credible fire scenario in the affected area of containment was very small due to the very low ignition probability and the small amount of intervening combustibles. This issue was determined to be a Non-Cited Violation (NCV) for failure to meet 10 CFR Part 50, Appendix R, requirements. The tracking number for this NCV is 50-306/2000005-02(DRP). The finding was assigned to Unit 2. (Section 4OA3.3)

Cross-cutting Issues: Human Performance

- NO COLOR. The licensee identified that on four separate occasions, within a relatively short period of time, errors occurred in the proper implementation of the safety tagging process. Individually, each of the deficiencies posed little or no increase in risk and were not evaluated using the Significance Determination Process due to their minor nature. However, the inspectors considered that these issues, in aggregate, constituted a human performance finding. The finding was assigned to Unit 1 and Unit 2. (Section 4OA4)

Report Details

Summary of Plant Status

Both units operated at or near full power for the entire inspection period until April 28, 2000, when Unit 2 tripped from approximately 22 percent power during a shutdown for refueling. Following the trip, the licensee began the Unit 2 refueling outage. Unit 2 remained in the outage through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

.1 Partial Walkdown of Unit 2 Auxiliary Feedwater (AFW) System Train A

a. Inspection Scope

The inspectors performed a partial walkdown of the Unit 2 AFW train A. This walkdown was performed to verify the operability of the redundant AFW train while the B train was out-of-service for planned maintenance. The AFW system was selected for this inspection due to its high importance as a core damage mitigating system for several accident sequences. The inspectors ensured that the configuration of the Unit 2 AFW system Train A was in accordance with applicable operating checklists and that the system could perform its required design basis function. As part of this inspection, the inspectors reviewed the following documents:

- System Prestart Checklist C28-7, “Auxiliary Feedwater System Unit 2,” Revision 42;
- Prairie Island Flow Diagram NF-39222, “Feedwater System,” Revision AW; and
- Prairie Island Design Basis Document for the Auxiliary Feedwater System, DBD SYS-28B, Revision 2.

b. Issues and Findings

There were no findings identified during this inspection.

.2 Complete Walkdown of the Unit 1 Residual Heat Removal (RHR) System

a. Inspection Scope

The inspectors performed a semi-annual complete walkdown of the Unit 1 RHR system. As part of this inspection, the inspectors reviewed ongoing system maintenance, outstanding work orders (WOs), and outstanding design issues for potential effects on the ability of the system to perform its design functions. The inspectors ensured that the present configuration of the Unit 1 RHR system was in accordance with applicable operating checklists and that the system could perform its required design basis function. The inspectors also performed a complete system status check, which verified acceptable material condition of system components, availability of electrical power to system components, essential support systems availability, and that ancillary equipment or debris did not interfere with system performance. The RHR system was selected for this inspection based on its importance as a mitigating system used to prevent core damage. As part of this inspection, the inspectors reviewed the licensee's historical computerized issue tracking and WO data base, as well as the following documents:

- Integrated Checklist C1.1.15-1. "Unit 1 Residual Heat Removal," Revision 24;
- Prairie Island Flow Diagram X-HIAW-1-31, "Residual Heat Removal System-Unit 1," Revision M;
- Prairie Island Design Basis Document for the Residual Heat Removal System, DBD SYS-15, Revision 3;
- Prairie Island Updated Safety Analysis Report, Section 10.2.4, "Residual Heat Removal System," Revision 20.

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 Prairie Island Nuclear Generating Plant Individual Plant Examination of External Events (IPEEE), NSPLMI-96001, Revision 0:

- Fire Area 20 (Unit 1 4160 volt safeguards switchgear room (Bus 16));
- Fire Area 22 (Unit 1 480 volt safeguard switchgear room (Bus 121));
- Fire Area 80 (Unit 1 480 volt safeguard switchgear room (Bus 111)); and
- Fire Area 81 (Unit 1 4160 volt safeguard switchgear room (Bus 15)).

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

- 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.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed operator performance during a simulator training scenario involving an inadvertent boron dilution, a dropped control rod, and a loss of coolant accident. The inspectors evaluated the following attributes of the activity:

- communications clarity and formality;
- timeliness and appropriateness of crew actions;
- prioritization, interpretation, and verification of alarms;
- correct use and implementation of procedures; and
- oversight and direction provided by the shift supervisor and shift manager.

As part of this inspection, the inspectors reviewed Simulator Exercise Guide 00-11, “Dilution/Rod Misalignment/ES-1.1,” Revision 0.

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:

- Plant Substation 10 Bank Transformer;
- Instrument Power; and
- Instrument Air.

These systems were selected based on their being designated as risk significant under the Maintenance Rule, or their being in the increased monitoring (Maintenance Rule category a(1)) group. The inspectors reviewed the Fourth Quarter Equipment Performance Report, dated February 4, 2000, the First Quarter Equipment Performance Report, dated May 2, 2000, as well as applicable system WOs and condition reports as part of this inspection.

b. Issues and Findings

There were no findings identified during this inspection.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

.1 Assessment and Management of Risk of Simultaneous Work on Several Unit 2 Systems

a. Inspection Scope

The inspectors reviewed the risk profile and work schedule for the week of April 15-21, 2000. That week was chosen due to the unusual combination of work on three Unit 2 mitigating systems; the RHR system, the safety injection (SI) system, and the charging system, which was scheduled to be performed simultaneously. The inspectors verified the availability of redundant trains, reviewed work plans for contingencies and efficiency, and monitored the performance of the work. As part of this inspection, the inspectors reviewed “Prairie Island Weekly Planning Meeting Results, 4/15/00 - 4/21/00,” and held discussions with members of the licensee’s risk assessment group.

b. Issues and Findings

There were no findings identified during this inspection.

.2 Emergent Work Control

a. Inspection Scope

The inspectors evaluated the following emergent work activities, in combination with scheduled work, to verify that adequate controls were maintained and that adequate precautions were taken to limit risk and decrease the probability of an initiating event.

- WO 0000953, “D1 Standby Jacket Coolant Pump Seal Leak,” which included replacement of the pump on the D1 diesel generator during a time when the D5 diesel generator and 25 safeguards bus was out-of-service; and

- WO 0003988, “Bank D Rods Stepped in Four Steps for no Apparent Reason,” which required that the Unit 1 rod control system be placed in manual and created the possibility of a rod control transient event during troubleshooting activities.

b. Issues and Findings

There were no findings identified during this inspection.

1R14 Personnel Performance During Nonroutine Plant Evolutions

a. Inspection Scope

The inspectors reviewed the preparation, implementation, and restoration activities associated with required switchyard maintenance in accordance with WO 9912487, “Inspect and Test 345 Kilovolt Bus 2 Relaying.” This evolution required the operators to perform numerous electrical switching operations and operate for an extended period of time with one of the main switchyard buses de-energized, increasing the probability of a loss of offsite power event.

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 risk-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:

- Safety Evaluation Screening 679, "Switchyard Configuration for Maintenance";
- Condition Report 20000601, "Category I Zone Doors Should Alarm if Held Open for >30 Seconds Per Updated Safety Analysis Report 10.3, SP [surveillance procedure] 1774 Test for Alarm in <1.5 Minutes"; and
- Condition Report 20001013, "Safeguards Relay 1SDX8-B did not Re-energize Completely While in SP 1032B, Relay Required Manual Assist to Completely Pick Up."

b. Issues and Findings

There were no findings identified during this inspection.

1R16 Operator Workarounds

.1 Review of Selected 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 20000744, "Overload Indication on East Hoist of Fuel Handling Crane"; and
- OWA 20001030, "Relay 1SDX8-B May Not Pick Up When Energized."

b. Issues and Findings

There were no findings identified during this inspection.

.2 Review of the Cumulative Effect of Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effect of OWAs on equipment availability, initiating event frequency, and the ability of the operators to respond to events. As part of this inspection, the inspectors reviewed the following licensee documents:

- "The 1st Quarter of 2000 Report on Operator Workarounds and Aggregate Assessment of OWAs," dated April 12, 2000;
- "Risk Assessment of Accumulative Effect of Unit 1 Equipment Degraded Conditions," dated April 20, 2000; and
- "Unit 1 Forced Outage Work Order Status," dated April 20, 2000.

The inspectors also attended two licensee meetings where the cumulative effect of operator workarounds were discussed.

b. Issues and Findings

There were no findings identified during this inspection.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors evaluated the completion of work for the on-line installation of modifications to the component cooling water supply to the spent fuel heat exchangers and replacement of one of the heat exchangers in accordance with Design Changes 99CC01, "Component Cooling Leakage Modification," and 99SF02, "Replace 122 Spent Fuel Pool Heat Exchanger." The inspectors reviewed configuration control and management of risk while the work was performed with both units online, flowpaths, training, work schedules, the effect on other equipment, and testing.

b. Issues and Findings

There were no findings identified during this inspection.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors witnessed testing for the components and systems listed below to ensure that the tests met the design bases and licensing basis commitments, that the testing demonstrated the equipment was capable of performing its design basis functions, and acceptance criteria were met.

- Control room dampers following installation of new dampers in accordance with Work Order 0000853, "Preoperational Test of Control Room Ventilation Dampers CD-34152 and CD-34176"; and

- Simultaneous RHR and SI motor-operated valves (MV) and the 21 SI pump following preventive maintenance (PM) in accordance with the following:
    - WO 9912292, “Breaker Electrical 5 Year PM - 21 RHR Heat Exchanger to 21 SI Pump MV-32208";
    - WO 9706969, “Breaker Electrical 5 Year PM - 21 RHR Heat Exchanger Component Cooling Inlet MV-32128";
    - WO 9911693, “RHR to 21 SI Pump D70 Inspection”; and
    - Test Procedure TP 2087, “Monthly Unit 2 SI Pump Lubrication,” Revision 1.
- The D5 diesel generator following a major overhaul in accordance with WO 0000586, “D5 Five Year PM.”

b. Issues and Findings

There were no findings identified during this inspection.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed activities associated with the Unit 2 refueling outage, that began on April 28, 2000. The inspectors reviewed the reactor cooldown rate, configuration management, clearance activities, reduced reactor coolant system (RCS) inventory conditions, and refueling operations for management of risk, conformance to the applicable procedures, and compliance with technical specifications. The following major activities were observed:

- outage planning meetings;
- transition to phase two cooling using RHR;
- draining the RCS from approximately 30 percent pressurizer level to the top of the RCS hot legs in preparation for steam generator nozzle dam installation;
- fuel handling activities;
- testing of RHR injection lines; and
- other general outage activities.

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

- Special Operating Procedure 2D2, “RCS Reduced Inventory Operation,” Revision 10;
- Operating Procedure 2C4.1, “RCS Inventory Control - Pre-Refueling,” Revision 10;
- Operating Procedure 2C15, “Residual Heat Removal System,” Revision 18;
- Operating Procedure C17, “Fuel Handling System,” Revision 27;
- Special Operating Procedure D5.1, “Spent Fuel Handling Operations,” Revision 21;
- Operating Procedure 2C19.1, “Containment System Integrity - Unit 2,” Revision 9;

- SP2092D, “Safety Injection Check Valve Test (Head On) Part D: Low Head SI Discharge Flow Path Verification,” Revision 3; and
- SP 2126, “Turbine Building Cooling Water Header Isolation SI Relays 2SI-12X and 2SI-22X Refueling Test.”

Coincident with the second week of the refueling outage, a Region III based radiation protection inspector was on site and reviewed a number of other outage related activities. Any findings associated with that inspection were documented in Inspection Report 50-282/2000007(DRS); 50-306/2000007(DRS).

b. Issues and Findings

Maintenance technicians made an error which resulted in Unit 2 having to be kept in a condition of increased risk for an extended period of time.

On May 4, 2000, with the RCS drained to the level of the hot legs for installation of steam generator (SG) nozzle dams in accordance with Special Operations Procedure D27.18, “Steam Generator Nozzle Dam Installation SG. No. 22,” Revision 17, maintenance personnel installed the primary bowl drain plug in the wrong hole. The drain plug was necessary to plug a small (less than 1 inch) drain hole at the bottom of the primary bowl which allowed residual water in the bowl to drain to the RCS cold leg. A maintenance technician installed the plug in a primary manway drain hole instead of the primary bowl drain hole. A second technician improperly independently verified the installation.

Due to the maintenance technician’s error, a bypass path was created around the nozzle dams from the reactor coolant loops to the 22 SG. When operations personnel began restoring the RCS from reduced inventory conditions, the primary bowl refilled and water was noticed spilling from a manway. A total of about 10 gallons of water was spilled. The refill was halted, inventory was reduced back to the hot leg level, and the problem was identified and corrected. The licensee issued Condition Report 20001336, “22 SG Bowl Plug Installed in Primary Manway Drain Hole, Bowl Plug Should Have Been Installed in Nozzle Drain Hole,” and initiated an Error Reduction Task Force investigation of the event.

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 the licensee spending over 7 additional hours (from 2:48 p.m. to 10:14 p.m.) at reduced inventory conditions with a time to boiling of about 15 minutes should decay heat removal have been lost. At the time the error was discovered, the plant had already spent about 50 hours at reduced inventory conditions. Since the probability of a loss of decay heat removal, reactor coolant inventory, or electrical power increased with exposure time, and the open drain hole would have complicated refilling the reactor coolant system if an alternate decay heat removal method, such as steam generators, would have been needed, the inspectors determined that the issue was a finding of potential risk significance requiring a Phase 2 SDP analysis in accordance with Table 1, Page T-10, of the manual chapter. The finding was referred to an NRC senior reactor analyst for further refinement of the SDP with risk To Be Determined. 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 draining and refilling the reactor vessel, of which Special Operations Procedure D27.18 was an example. On May 4, 2000, the licensee failed to properly implement Special Operations Procedure D27.18, Appendix C, Step U, which required the technician to install the steam generator bowl plug, and Appendix D, Step G, which required another technician to verify that the bowl plug was installed. This is considered an Apparent Violation of Technical Specification 6.4 pending the NRC's determination of the risk significance (50-306/2000005-01(DRP)).

1R22 Surveillance Testing

a. Inspection Scope

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

- SP 1234, "Unit 1 Auxiliary Feedwater Pump Suction and Discharge Pressure Switch Calibration," Revision 10;
- SP 2088, "Safety Injection Pump Test," Revision 39; and
- SP 2072.12, "Local Leak Rate Test of Penetration 12, Charging to RCS," Revision 14.

b. Issues and Findings

There were no findings identified during this inspection.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Modification 00T070, "Portable Air Movers Located in the Auxiliary Building." As part of this inspection, the inspector also reviewed WO 9911782, "Inspect and Hookup Auxiliary Building 735' Air Movers," and Safety Evaluation 671, "Portable Air Movers in the Auxiliary Building." The inspectors also discussed this temporary modification with the responsible system engineer. The inspectors verified that the temporary modification installation did not affect the operability of the auxiliary building special ventilation system, did not involve increased safeguards electrical loads, and that it was installed consistent with the temporary modification instructions.

b. Issues and Findings

There were no findings identified during this inspection.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Safety System Unavailability, Emergency AC [alternating current] Power

a. Inspection Scope

The inspectors verified the Safety System Unavailability, Emergency AC Power, Performance Indicator data reported by the licensee for April 1999 through March 2000 for Unit 1 and Unit 2. This was accomplished, in part, through evaluating the Limiting Conditions for Operation Log times for the emergency diesel generator system and required support systems, review of applicable WOs, and discussions with licensee personnel.

b. Issues and Findings

There were no findings identified during this inspection.

4OA3 Event Followup

Cornerstones: Initiating Events, Mitigating Systems

.1 Blocked High Energy Line Break Door

a. Inspection Scope

On April 3, 2000, the licensee informed the NRC in accordance with 10 CFR 50.72 of a condition outside of the design basis of the plant. Specifically, scaffolding had been installed that partially blocked doors 155 and 177 between the auxiliary building and the fuel building. These doors were designed to open to relieve pressure in the auxiliary building in the case of a high energy line break. The inspectors performed an initial review of the risk significance of the issue and followed up on the licensee's response.

On April 17, 2000, the licensee withdrew the event notification based on an analysis which showed that the partially blocked doors would not have had a significant effect on the peak pressure or temperature consequences of a high energy line break event in the auxiliary building.

b. Issues and Findings

There were no findings identified during this inspection.

.2 Unit 2 Reactor Trip

a. Inspection Scope

On April 28, 2000, the licensee informed the NRC in accordance with 10 CFR 50.72 that Unit 2 had tripped from approximately 22 percent power while shutting down for the refueling outage. The reactor trip was caused by a turbine trip. The turbine trip was the result of a high water level signal from the 23B low pressure feedwater heater. Preliminary investigations by the licensee revealed that no actual high level condition existed in the feedwater heater. The only complication with the trip was that operators needed to close the feedwater containment isolation valves, in accordance with MV-32028 and MV-32029 to control the RCS cooldown rate.

The inspectors verified that operator response to the trip had been correct and that all equipment required to shut down the reactor had functioned as required. The licensee's investigation into the cause of the high level trip signal was being tracked in their corrective action program as Condition Report 20001202, "Unit 2 Reactor Trip by Turbine Trip due to High Feedwater Heater Level." The licensee intended to issue Licensee Event Report 50-306/20001 within 30 days after the event with additional information.

The licensee also notified the NRC in accordance with 10 CFR 50.72 that the feedwater containment isolation valves had apparently not fully closed when operated as described above. The inspectors reviewed Condition Report 20001203, "Feedwater to Steam Generator Isolation Valves May not Have Closed After Unit 2 Reactor Trip," in which the licensee documented that, upon further investigation, the valves did close. The NRC notification was retracted on May 17, 2000.

b. Issues and Findings

There were no findings identified during this inspection.

.3 Unit 2 Pressurizer Power Operated Relief Valve and Block Valve A and B Train Separation

a. Inspection Scope

On May 2, 2000, the licensee informed the NRC in accordance with 10 CFR 50.72 that the cable separation distances required by 10 CFR Part 50, Appendix R, were not met in the Unit 2 containment for both trains of redundant pressurizer power operated relief valves (PORV) and block valves. The inspectors reviewed the design requirements, performed a walkdown of the affected area, and reviewed the issue's applicability to Unit 1. As part of this inspection, the inspectors also reviewed the following documents:

- Condition Report 20000832, "Fire Area 01 and 71, Appendix R Exemption Compliance Concerns Associated with Pressurizer PORV and Block Valve Cable Separation";
- Plant Safety Procedure F5, Appendix D, "Impact of Fire Outside Control/Relay Room," Revision 5;

- July 31, 1984, letter from James R. Miller, Chief, Operating Reactor Branch #3, Division of Licensing, United States Nuclear Regulatory Commission, to D. M. Musolf, Nuclear Support Services Department, Northern States Power Company, regarding exemptions to 10 CFR Part 50, Appendix R.

b. Issue and Findings

During a walkdown in the Unit 2 containment, licensee engineers discovered that the cables in question did not meet Appendix R separation requirements.

The walkdown was performed after a previous drawing review indicated that inadequate cable separation might exist. The cables of redundant trains of equipment were required by 10 CFR Part 50, Appendix R, to be separated by at least 20 feet. In this case, the licensee discovered that one set of cables was as close as 13 feet and the another set of cables was as close as 18 feet. Among the actions for a fire in the containment, as specified in Procedure F5, Appendix D, was a requirement to close the pressurizer block valves and de-energize the power supplies for the valves. However, the valves could reopen due to multiple sustained hot shorts. In addition, even though Procedure F5, Appendix D, specified isolation of instrument air to containment, the PORVs had accumulators that could have allowed spurious operation due to external hot shorts. Opening of redundant PORV and block valves in one of the lines could result in opening of a high/low pressure system interface and a loss of RCS pressure control resulting in the loss of natural circulation.

Based on a preliminary screening using Phase 1 of the SDP of Inspection Manual Chapter 0609, Original Revision, Appendix F, "Fire Protection and Post-Fire Safe Shutdown SDP," the inspectors determined that the issue met the requirements for further review using the Phase 2 SDP by regional and headquarters fire protection specialists. In this case, a fire barrier was affected due to the inadequate cable separation. In addition, no automatic fire suppression existed in containment and manual fire suppression would be hampered by difficulty in rapidly accessing the area. In the specialists' Phase 2 SDP, the NRC determined that a credible fire scenario did not exist in the applicable area of containment due to a very low ignition probability and the small amount of intervening combustibles. Thus, the finding was determined to be of very low safety significance (GREEN) and within the licensee's response band. The finding was assigned to Unit 2. The licensee intended to provide additional details regarding the issue in Licensee Event Report 50-306/20002.

The licensee intended to correct the problem in Unit 2 before startup from the ongoing refueling outage by placing the cables in conduit. The licensee also suspected that a similar condition might exist in the Unit 1 containment, although it may only affect one set of redundant valves. The licensee intended to inspect the configuration in the Unit 1 containment during the next refueling outage or other appropriate opportunity. In the interim, the licensee had evaluated the potential condition as operable, but degraded, with operation justified until the next refueling outage. This operability assessment was documented in Condition Report 20000832.

Appendix R of 10 CFR Part 50, Section III.G.2, as modified by an exemption granted for Prairie Island by NRC letter dated July 31, 1984, required, as one authorized means of fire protection, that cables, equipment, and associated nonsafety circuits of redundant trains in noninerted containments be separated by a horizontal distance of more than 20 feet. The licensee chose to employ this method of protection for redundant pressurizer PORV and block valve cables. Failure to provide the specified cable separation for those cables was a violation of Appendix R fire protection requirements. We are treating this violation as a Non-Cited Violation, consistent with the NRC's Enforcement Policy May 1, 2000; (65 FR 25368); (50-306/2000005-02(DRP)). This violation is in the licensee's corrective action system as Condition Report 20000832.

4OA4 Cross-Cutting Issues

Human Performance Problems

a. Inspection Scope

During the normal course of inspection activities, the inspectors became aware of several examples of the licensee's safety tagging procedure not being correctly implemented. The inspectors reviewed each occurrence.

b. Issues and Findings

The inspectors noted that on four separate occasions, during a relatively short period of time, problems occurred in the proper implementation of the safety tagging process. Each of the cases was licensee identified. The examples noted were as follows:

- On April 4, 2000, operators hung a Hold card on the wrong 480 volt AC breaker. The Hold card was hung on the breaker for the 122 battery room cooler instead of the 121 battery room cooler. This equipment served both units. Neither component was in service at the time of the error. This deficiency was placed in the licensee's corrective action program as Condition Report 20001171.

- On May 3, 2000, Quality Services personnel discovered that Hold tags for Unit 2, Bus 21 and 22, potential transformer fuses were placed on the fuses instead of the drawer handle as required by Administrative Work Instruction 5AWI 3.10.0, "Control and Operation of Plant Equipment," Revision 9. The deficiency did not result in the components being energized, but might have resulted in replacement fuses being installed without noticing the tags. This deficiency was placed in the licensee's corrective action program as Condition Report 20001318.

- On May 5, 2000, during a system lineup per Maintenance Procedure D15.1 "Reactor Coolant Pump Seal Replacement," Revision 20, a valve was positioned open and a safety tag was hung out of procedural order. The valve in question was a drain valve on the seal injection water line to the Unit 2, 21 reactor coolant pump, located just upstream of a capped drain line. If the normal practice of removing the pipe cap, in conjunction with opening the drain valve, would have been employed, a small direct leak path from the RCS would have been created. This deficiency was placed in the licensee's corrective action program as Condition Report 20001359.

- On May 7, 2000, the licensee discovered that the Unit 2, 21 and 22 RHR pump suction pressure root isolation valves had been shut and safety tagged in the closed position. These valve were required to be safety tagged in the open position by Operating Procedure 2C4.1, “RCS Inventory Control - Pre-Refueling,” Revision 10. The licensee informed the inspectors that these safety tags were part of a stock outage isolation and that the error occurred during a modification to that stock isolation. The operators that were initially assigned to hang the safety tags requested that the description printed on the tags be modified to more closely match the local identification label at the valves. During the modification of the tag description, the required position on the safety tags was inadvertently changed from “open” to “closed.” This error was not identified in the change review process and when the isolation was sent out the second time the valves were shut and the safety tags were hung on the valves. No automatic safety feature was disabled by this incorrect valve lineup. This deficiency was placed in the licensee’s corrective action program as Condition Report 20001383.

Individually, each of the deficiencies described above posed little or no increase in risk. Although licensee procedures for equipment control (locking and tagging) required by Technical Specification 6.4 were improperly implemented, each deficiency constituted a violation of minor significance not subject to formal enforcement action in accordance with the NRC’s Enforcement Policy May 1, 2000; (65 FR 25368). The issues were not evaluated using the SDP due to their minor nature. Three of the four errors occurred during a refueling outage after a long period of sustained operation and infrequent configuration changes in both units. The level of configuration control and tagging activities dramatically increased in the outage, which created more opportunities for errors at a time when defense in depth was reduced.

The inspectors determined that these issues constituted a finding in the cross-cutting area of human performance. The finding was assigned to Unit 1 and Unit 2 and was not assigned a risk color. In addition to taking immediate corrective actions for each individual error, the general superintendent plant operations instituted peer checking requirements for certain safety tagging activities. Action 20001366 was entered into the corrective action system to monitor the effectiveness of the peer checking requirements and other generic corrective actions.

4OA5 Other

Generic Issues

.1 Draindown During Shutdown and Common-Mode Failure (Temporary Instruction 2515/142)

a. Inspection Scope

The inspectors reviewed the licensee’s actions taken in response to Generic Letter 98-02, “Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition.” The review included discussions with operations, training, and engineering personnel; system walkdowns; and an evaluation of the following documents:

- Northern States Power letter to NRC, dated November 24, 1998, "Response to Generic Letter 98-02";
- Abnormal Operating Procedure 1C15 AOP2, "Loss of Coolant Inventory with RHR in Operation," Revision 2;
- Abnormal Operating Procedure D2 AOP1, "Loss of Coolant While in a Reduced Inventory Condition," Revision 5;
- WO 9911693, "P32208 RHR to 21 SI Pump D70 Inspection," (periodic diagnostic testing of the motor-operator for the 21 RHR heat exchanger to the 21 SI pump suction isolation valve);
- Operating Procedure 1C15, "Residual Heat Removal System," Revision 19;
- Administrative Work Instruction 5AWI 3.10.1, "Methods of Performing Independent Verification," Revision 7;
- 5AWI 3.10.0, "Control and Operation of Plant Equipment," Revision 9;
- Section Work Instruction SWI 0-3, "Safeguards Hold Cards and Component Blocking or Locking," Revision 57; and
- SP 1369, "Exercising 11 and 12 RHR Pump Suction Line Check Valves," Revision 5.

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

There were no findings identified during the inspection.

4OA6 <u>Meetings, including Exit</u>

<u>Exit Meeting Summary</u>

The inspectors presented the inspection results to Mr. D. Schuelke and other members of licensee management at the conclusion of the inspection on May 18, 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
J. Gonyeau, Life Cycle and Management Support Engineer
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

50-306/2000005-01(DRP)	AV	Failure to Properly Implement Procedures for Installing Nozzle Dams on 22 Steam Generator (1R20)
50-306/2000005-02(DRP)	NCV	Cable Separation Distances (per Fire Protection Criteria) Not Met in Unit 2 Containment for Redundant Pressurizer Power Operated Relief and Block Valves (4OA3.3)

Closed

50-306/2000005-02(DRP)	NCV	Cable Separation Distances (per Fire Protection Criteria) Not Met in Unit 2 Containment for Redundant Pressurizer Power Operated Relief and Block Valves (4OA3.3)

Discussed

None

LIST OF ACRONYMS USED

AC	Alternating Current
AFW	Auxiliary Feedwater
AV	Apparent Violation
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
FR	Federal Register
IPEEE	Individual Plant Examination of External Events
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
WO	Work Order

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.