July 10, 1998

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

SUBJECT: NRC SPECIAL INSPECTION REPORT NO. 50-282/98010(DRS); 50-306/98010(DRS) AND NOTICE OF VIOLATION

Dear Mr. Wadley:

On June 12, 1998, the NRC completed a special inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection.

On June 5, 1998, the plant experienced a reactor trip as the result of a dropped control rod. This special inspection consisted of a review of selected equipment abnormalities, procedure adequacy, and operations staff performance associated with the plant response and subsequent placement of the plant in a safe shutdown condition. Areas inspected are identified in the enclosed report.

The inspection revealed that your operators initially did a good job responding to the unexpected reactor trip, and took appropriate action based on plant indications. However, their training and practical experience had not prepared them to maintain the plant in a hot shutdown condition with the main steam isolation valves closed and using the steam generator power operated relief valves to dissipate decay heat. Additional weaknesses that contributed to the inability to maintain adequate decay heat removal included: an inadequate procedure for dumping steam; one instance of a lack of three part communications; lack of maintaining a consistent oversight of plant status; and apparent lack of fidelity between the simulator and plant power operated relief valve response.

Based on the results of this inspection one violation of NRC requirements was identified and is cited in the enclosed Notice of Violation (Notice). The violation involved inadequate procedural guidance for dumping steam using the steam generator power operated relief valves while maintaining the plant in a prolonged hot shutdown mode with the main steam isolation valves closed. Please note that you are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR Part 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room.

Sincerely,

Original /s/ R. N. Gardner for
John A. Grobe, Director
Division of Reactor Safety

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

Enclosures:
1. Notice of Violation
2. Inspection Report 50-282/98010(DRS); 50-306/98010(DRS)

cc w/encl:
Plant Manager, Prairie Island
State Liaison Officer, State of Minnesota
State Liaison Officer, State of Wisconsin
Tribal Council Prairie Island Dakota Community

In accordance with 10 CFR Part 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room.

Sincerely,

John A. Grobe, Director
Division of Reactor Safety

Docket Nos.: 50-282; 50-306
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Enclosures: 1. Notice of Violation
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cc w/encl: Plant Manager, Prairie Island
State Liaison Officer, State of Minnesota
State Liaison Officer, State of Wisconsin
Tribal Council
Prairie Island Dakota Community

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NOTICE OF VIOLATION

Northern States Power Company | Docket No. 50-282; 50-306
Prairie Island Station | License Nos. DPR-42; DPR-60

During an NRC inspection conducted from June 5 through 12, 1998, one violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

> Criterion V of 10 CFR 50, Appendix B, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with those procedures.
>
> Contrary to the above, the inspectors identified that on June 5, 1998, emergency operating procedure 1ES-0.1, "Reactor Trip Recovery," Revision 13, lacked adequate guidance for dumping steam using the steam generator power operated relief valves with the main steam isolation valves closed. Specifically, the procedure did not provide instructions for controlling reactor coolant system temperature as evidenced by the inadvertent lift of one steam generator main steam safety valve.
>
> This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, you are hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington D.C. 20555 with a copy to the Regional Administrator, Region III, 801 Warrenville Road, Lisle, Illinois 60532-4351, and a copy to the NRC Resident Inspector at the Prairie Island Nuclear Plant within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be placed in the NRC Public Document Room (PDR), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction. If personal privacy, or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.790(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated at Lisle, Illinois,
this 10th day of July 1998

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report Nos:	50-282/98010(DRS); 50-306/98010(DRS)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	June 5 through 12, 1998
Inspectors:	M. Bielby, Reactor Engineer / Team Leader S. Ray, Senior Resident Inspector, Prairie Island R. Winter, Reactor Engineer
Approved by:	M. Leach, Chief, Operator Licensing Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Station, Unit 1 and Unit 2
NRC Inspection Reports 50-282/98010; 50-306/98010

This special inspection report covers a period of on-site inspection into the circumstances surrounding the Unit 1 reactor trip due to a dropped control rod and the actions taken for the recovery to safe shutdown conditions on June 5, 1998. The conduct of operations of the Prairie Island staff for this event generally was good during the initial stages of the event; however, the inspectors noted some equipment problems, and weaknesses in procedures, communications, training, and performance.

Operations

- The operator's initial response and actions taken based on indications for the dropped rod event were good; however, subsequent operator actions to stabilize the plant and dissipate decay heat were not completely effective as evidenced by the inadvertent rise in T_{ave} and lifting of the steam generator (SG) #1A safety valve. (Sections O1.1 and O4.1)

- The operators lacked adequate procedural guidance for stabilizing the plant and dissipating decay heat by dumping steam using the SG power operated relief valves (PORVs) during a hot shutdown condition with main steam isolation valves (MSIVs) closed. A violation of 10 CFR Part 50, Appendix B, Criterion V was issued. (Sections O3.1 and O4.1)

- During subsequent actions to stabilize the plant, a lack of three part communication, a lack of consistent plant oversight, and unfamiliarity of SG PORV response contributed to failure to adequately remove decay heat. (Section O4.1)

- Operator training and practical experience at maintaining the plant in a hot shutdown condition with the MSIVs closed and using SG PORVs for decay heat dissipation was limited. (Sections O4.1 and O5.1)

- The simulator SG PORV fidelity was dissimilar to the plant and the licensee wrote a non-conformance report. (Section O5.1)

Report Details

Brief Narrative of the Rod Drop Event

The Unit 1 reactor was operating at 100% power on June 5, 1998, and experienced an unexpected automatic trip. The operators verified all control rods fully inserted and identified that the first out indication was a negative flux-rate trip. The control room received reports of steam release in the turbine building (TB) that was later identified as an unexpected relief valve lift on the 15A feedwater heater (FWH). One of the two operating main feedwater pumps (MFPs) tripped, as expected, and operators tripped the remaining MFP to minimize secondary inventory loss. This action reseated the lifted FWH relief valve. The operators used the atmospheric steam dumps to initially remove decay heat. Operators closed the MSIVs as a result of excessive reactor coolant system (RCS) cooldown and in response to the report of steam in the TB. Both the #11 turbine driven auxiliary feedwater (TDAFW) and #12 motor driven auxiliary feedwater (MDAFW) pumps automatically started and remained in service to supply auxiliary feedwater (AFW) to both SGs. One control room operator was dedicated to maintain both SG water levels 35% - 37% as indicated on narrow range (NR) meters. Approximately two hours after efforts to stabilize the plant, one of the five SG "A" main steam safety valves (#1A) unexpectedly lifted and reseated. The resulting swell caused indicated NR level in SG "A" to increase to 50%, and SG "B" to 45%, respectively. The licensee later identified that the operator had placed both SG PORVs in the manual mode just prior to the unexpected SG main steam safety valve lift.

I. Operations

O1 Conduct of Operations

O1.1 Sequence of Events

a. Inspection Scope (71707, 93702)

The inspectors formulated a sequence of events based on the following information: interviews conducted with the licensee's management, operations and engineering staff; review of operator logs, parameter recorders, process computer and Emergency Response Computer System (ERCS) information; and observation of control room panels.

b. Observations and Findings

The following information describes the sequence of events (Central Daylight Time) commencing with the automatic reactor trip of Unit 1 from 100% power as reconstructed by the NRC inspection team:

Friday, June 5, 1998

06:58 pm	Unit 1 received an automatic reactor trip, operators identified the first out annunciator as the negative flux rate trip. Operators entered 1E-0, "Reactor Trip Or Safety Injection," Revision 17. Operators verified all control rods fully inserted, one of two operating MFPs (#11) received automatic trip, #11 TDAFW and #12 MDAFW pumps started automatically with discharge flow at 550 gpm. Average RCS temperature (T_{ave}) dropped from 559 to 539 °F, and SG levels dropped from 45% to 0% NR.
07:01 - 07:04 pm	T_{ave} continued to drop to 538 °F, control room received Zone 15 TB fire alarm and report of steam release in the TB. Operators completed procedure 1E-0 and entered 1ES-0.1, Reactor Trip Recovery, Revision 13. AFW flow was throttled to 200 gpm to limit cooldown, MSIVs closed to limit cooldown and stop steam release.
07:07 - 07:15 pm	Operators received report that steam was due to the lift of the 15A FWH tube side relief. Operators stopped the running #12 MFP and condensate pump to minimize secondary inventory loss and reduce 15A FWH tube side pressure. The lifted 15A FWH relief closed, T_{ave} increased to 547 °F, and continued to rise.
07:17 pm	AFW flow was increased to 270 gpm.
07:19 pm	T_{ave} at 555 °F, SG steam pressure at 1050 psig (SG PORV setpoint) and both PORVs automatically opened.
07:45 pm	SG levels at 10% and continued to rise.
07:53 pm	12 SG PORV setpoint dialed down in automatic to open valve more and reduce pressure. However, opening 12 SG PORV caused 11 SG PORV to close and cycle.
08:08 pm	SG level approached normal band of 33 +/- 5%; however, AFW flow throttled to 60 gpm and caused SG level to decrease from 30% to 25% over the next four minutes.
08:10 pm	11 SG PORV setpoint dialed down in automatic, caused valve to open more and reduce pressure.
08:12 - 08:24 pm	AFW flow increased to 200 gpm in several steps, SG levels at 25% and started to increase again.

08:45 -
09:04 pm SG levels approached normal band of 33 +/- 5%, AFW flow throttled down to 50 gpm in several steps. SG levels continued to rise slowly from 33% to 36%. During this period it appeared that the operator decreased the SG PORV automatic setpoints in an attempt to open the PORVs more and reduce SG pressure. On the average, SG PORVs swung open and closed 10-15% while the controller output changed 30-40%. SG levels shrank and swelled approximately +/- 2% while the overall level slowly increased toward the administrative procedural limit of 38%.

NOTE: At 09:03 pm both SG PORV setpoints appeared to have been increased while in automatic which closed the valves more and reduced the level swells. However, the decay heat removal was decreased which caused T_{ave} to start increasing from 552 °F.

09:07 pm Both SG PORVs placed in manual with “11" at approximately 22% demand, and “12" at 28%. The manual SG PORV demand was considerably less than when in automatic which closed the valves more and caused T_{ave} to increase rapidly from 553 °F.

09:12 pm T_{ave} at 557 °F, SG steam pressure at 1070 psig and one (#1A) of five main steam safety valves on “A" SG lifted and reseated which swelled the “A” SG level from 37% to 50%, and the “B” SG level to 45%.

09:16 pm T_{ave} bottomed out at 547 °F due to the SG safety valve lifting and reclosing, and then started to rise again.

09:24 pm T_{ave} at 555 °F, both SG PORVs returned to automatic mode and rapidly opened and closed when SG steam pressure was greater than the PORV setpoint (1050 psig). 12 SG level briefly swelled from 38% to 45%.

09:25 -
11:00 pm Plant stabilized and slowly brought to normal hot shutdown conditions. Plant staff investigating failure of 86G relay to lockout generator output breakers, lack of procedural guidance in 1ES-0.1 to bypass a recently installed backup synch check relay to allow reclosing the generator output breakers, cause of the automatic reactor trip, and unexpected lifting of the 15A FWH relief valve.

c. Conclusions

The operators’ initial response and actions taken based on indications for the dropped rod event were good; however, subsequent operator actions to stabilize the plant and dissipate decay heat were not completely effective as evidenced by the inadvertent rise in T_{ave} and lifting of the SG #1A safety valve.

O3 Operations Procedures and Documentation

O3.1 <u>Lack of Guidance for Dumping Steam Using SG PORVs</u>

a. <u>Inspection Scope (71707, 93702)</u>

The inspectors performed the following to determine the adequacy of guidance for dumping steam using SG PORVs: reviewed 1ES-0.1, "Reactor Trip Recovery," Revision 13; interviewed licensed operators and management personnel; reviewed parameter recorders, process computer and ERCS information.

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

The Unit 1 EOP, 1ES-0.1, Step 5 (bullet under "Response Not Obtained" column) directed the operator to "Dump steam with SG PORVs," but did not provide any further guidance or reference that described how to perform the evolution. During the plant stabilization phase of the reactor trip recovery, the operator was required to maintain SG levels 28 - 38%. The operator initially left both SG PORVs in the normal automatic configuration and was very slowly adjusting the controller pot down from the normal operating setpoint of 75% (1050 psig) to the no load setpoint of 71.5% (1005 psig). The PORVs' responsiveness resulted in erratic SG level swings. In lieu of procedural guidance and with the PORV auto setpoint at approximately 74.2% (1040 psig), the lead reactor operator (LRO) placed both SG PORV controllers in manual to reduce the erratic SG level swings and attempted to maintain SG level less than the 38% administrative limit by controlling AFW flow. However, the operator failed to open the PORVs sufficiently and the dissipation of decay heat was inadequate. As a result, T_{ave} continued to increase which caused the SG pressure to increase to the 1A SG safety valve setpoint of 1075 psig and it cycled open and close. The lack of adequate procedural guidance for dumping steam using SG PORVs was considered a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," (50-282/98010-01(DRS)); (50-306/98010-01(DRS)).

Subsequent to the event, the licensee revised both unit EOPs, 1ES-0.1 and 2ES-0.1, to direct reduction of the SG PORVs auto setpoint to 71.5% (1005 psig) if MSIVs are closed. Additionally, the same procedures were changed to direct the operator to stop feed flow to a SG if level reaches 40%, vice 50%.

c. <u>Conclusions</u>

The operators lacked adequate procedural guidance for stabilizing the plant and dissipating decay heat by dumping steam using the SG PORVs during a hot shutdown condition with MSIVs closed. A violation of 10 CFR Part 50, Appendix B, Criterion V was issued.

O4 Operator Knowledge and Performance

O4.1 Operator Response to Rod Drop Event

a. Inspection Scope (71707, 93702)

The inspectors reviewed operator performance based on their initial response to the reactor trip and mode change to hot shutdown conditions. The inspectors based their findings on the following: interviews conducted with operations and engineering staff; review of operator logs, parameter recorders, process computer and ERCS information; review of alarm response, emergency, abnormal, and normal operating procedures.

b. Observations and Findings

The Unit 1 control room operators' initial response to the rod drop event was good. The shift manager (SM) assumed the role of shift technical advisor (STA), the Unit 1 shift supervisor (SS) assumed the role of emergency operating procedure (EOP) reader, the Unit 1 LRO took control of the secondary plant, and the other Unit 1 reactor operator (RO) took control of the primary plant. The crew correctly identified that an automatic reactor trip had occurred and promptly entered EOP 1E-0, "Reactor Trip Or Safety Injection," Revision 17. After completing the specified procedural actions, the crew correctly transitioned to 1ES-0.1, "Reactor Trip Recovery," Revision 13. The LRO appropriately throttled AFW flow to limit cooldown. A TB fire alarm was received, and after investigating, field operators identified an unexpected steam release in the TB. Concurrently, control room personnel identified an excessive primary cooldown based on a T_{ave} decrease to 538 °F. The control room operators responded to the excessive primary cooldown and closed the MSIVs and bypass valves. The single operating MFP and condensate pump were stopped to minimize secondary inventory loss. Further reports from the TB clarified the steam release had come from an unexpected lifted tube side relief on the 15A FWH that reseated after tripping the MFP. As a result of those actions, T_{ave} increased to 547 °F and continued to slowly rise. The operators attempted to stabilize the plant in a hot shutdown condition with the MSIVs closed and maintain the following parameters as specified by 1ES-0.1: pressurizer (PRZR) pressure between 2220 and 2250 psig; PRZR level between 19 and 23%; SG NR level between 30 and 36%; and RCS T_{ave} between 545 and 549 °F.

The crew was directed to maintain a plant condition that had not been practiced during simulator training. The crew had used PORVs for post accident cooldown in several simulator scenarios; however, they had not maintained a hot shutdown condition with the MSIVs closed and using SG PORVs for decay heat removal. Additionally, they determined the plant was stabilized and transitioned from 1ES-0.1, "Reactor Trip Recovery," to 1C1.3, "Unit 1 Shutdown," Revision 40. However, even though plant parameters were not changing rapidly, the SG levels continued to trend toward the administrative and design limits, and T_{ave} was actually 552 °F vice the required 545 - 549 °F.

The STA/SM and SS determined the plant was stable because they had transitioned to the shutdown procedure. Consequently they relaxed their continued oversight of the plant status and became focused on their administrative duties. The STA observed that no critical safety functions had been entered and resumed the SM duties of notifications. Likewise, the SS focused his attention on followup of equipment problems with the FWH relief valve and generator output breaker relays, procedure problem with the backup bypass for the synch check relay, restoring the fire alarms, diagnosing the cause of the reactor trip, and completing logs.

The lack of adequate procedural guidance was a contributor to the subsequent poor operator performance. The LRO was required to maintain SG levels 33+/-5%, and had been periodically throttling AFW flow. The LRO was also directed to dump steam with SG PORVs in accordance with 1ES-0.1, but was not provided with any further guidance that described how to perform the evolution. The LRO initially left both SG PORVs in the normal automatic configuration and very slowly started to adjust the controller pot down from the normal operating setpoint of 75% (1050 psig) to the no load setpoint of 71.5% (1005 psig).

The erratic response of the SG PORVs was unexpected. The LRO had very slowly decreased the SG PORV setpoint to 74.2% (1040 psig). However, the PORV operation was very responsive and caused erratic SG level swings which was unexpected to the LRO. The PORVs opened every 5 - 10 seconds and caused SG level swell and shrink of about 2%.

An instance of poor communications and lack of communications contributed to the indicated SG level exceeding the design limit, inadequate dissipation of decay heat, and lifting of the main steam safety valve. The LRO tried to maintain both SG levels within the procedural limits. The automatic response of the PORVs and erratic SG level swings were unexpected. The LRO stated he made a verbal announcement that he was placing the SG PORVs in manual; however, no acknowledgment was made by any of the other control room operators. As such the communications were not in accordance with Section Work Instruction (SWI) O-24, “Operation Section Communications,” Revision 4. When one SG level approached the 38% limit the LRO placed both SG PORVs in manual with each PORV approximately 50% open. The operator decreased AFW flow to maintain SG level less than the 38% limit. The PORVs were insufficiently opened to dissipate the decay heat and T_{ave} continued to increase which caused the SG pressure to increase to the 1A SG safety valve setpoint of 1075 psig, and it cycled open and close. The cycling of the safety valve resulted in a large SG swell to 45-50% which alerted the SS. The LRO informed the SS that both SG PORVs were in manual. The SS checked safety valve tailpipe temperatures and determined the 1A safety on 11 SG had cycled. T_{ave} decreased to a minimum of 547 °F due to the open safety valve. The LRO returned the SG PORV control to automatic within about 12 minutes at which time the PORVs briefly cycled because steam pressure was greater than 1050 psig. The plant was stabilized and in hot shutdown conditions within about another 30 minutes.

c. Conclusions

During subsequent actions to stabilize the plant a lack of three part communication, lack of consistent plant oversight, and unfamiliarity of SG PORV response contributed to failure to adequately remove decay heat.

O5 Operator Training and Qualification

O5.1 SG Level / SG PORV / Hot Shutdown With MSIVs Closed

a. Inspection Scope (71707, 93702)

The inspectors interviewed training and operations staff and management, and observed a scenario run under hot shutdown conditions with MSIVs closed.

b. Observations and Findings

The inspectors requested the training staff to run a scenario under hot shutdown conditions with MSIVs closed to observe operation of the SG PORVs and resulting SG level shrink and swell. The inspectors observed that the simulator SG PORV response was much smoother and resulted in no erratic SG shrink and swell when compared to the recorder traces for SG level and PORV position taken during the plant event. The licensee identified the plant SG PORV gain was set at “20", and the integral at “0”, but was not sure if the simulator modeling corresponded to the plant. The licensee stated it normally reviewed all plant modifications and work packages to determine applicability to potential simulator hardware or software changes. The licensee wrote a non-conformance report to verify the plant SG PORV operation and to determine the simulator SG PORV fidelity to actual plant operation and to investigate how the simulator modeled SG level and AFW flow.

During the post event interviews, several operators identified they had been directed to maintain a plant condition that they had little training and practical experience performing. Operators had used PORVs for post accident cooldown in several simulator scenarios; however, they had not maintained a hot shutdown condition with the MSIVs closed and using SG PORVs for decay heat dissipation. The training staff verified that little time had been spent in dynamic scenarios under hot shutdown conditions, but stated that training would be set up for the next requal training cycle (mid July, 1998) to discuss the rod drop event and maintenance of hot shutdown conditions in detail; emphasize the importance of the SG PORVs to safety; discuss the conflict of SG level, AFW flow, and maintaining RCS temperature; discuss new operational guidelines; discuss the expectation for use of three part communications and plant oversight; and run a similar dynamic scenario event on the simulator. The licensee stated that an e-mail would be sent to all operators describing the event, equipment, procedural and operator performance weaknesses identified during the event, and Just-In-Time training would be scheduled.

c. Conclusions

Operator training and practical experience at maintaining the plant in a hot shutdown condition with the MSIVs closed and using SG PORVs for decay heat dissipation was limited. The simulator SG PORV fidelity was dissimilar to the plant.

III. Engineering

E1 Conduct of Engineering

E1.1 Root Cause of Rod Drop (G7)

a. Inspection Scope (71707, 93702)

On June 5, 1998, the plant experienced a negative rate reactor trip as the result of a dropped control rod (G7). The inspectors assessed the licensee's investigation team review of the root cause for the dropped control rod.

b. Observations and Findings

The licensee's initial root cause identification of the control rod drop was inconclusive. The licensee identified the stationary gripper coil fuse had blown on control rod #G-7 due to a ground in the wiring somewhere between the edge of the reactor cavity and the reactor head. The affected control rod cable and four other potentially degraded control rod cables were replaced. Two of the cables exhibited lower than expected cable resistance readings, and the other two cables were located in the center, higher temperature, region of the reactor. The licensee added a moisture barrier tape, meggered and pin to pin resistance checked connectors, replaced all fuses with a new model on all 29 rods, and scheduled rod timing checks.

The failed cable was shipped to the vendor for analysis. The preliminary report identified that a black carbonized material in the connector had created an arc between the conductors when a meggering voltage was applied. Further chemical analysis was scheduled to identify the source of the material and the root cause determination was inconclusive as to whether the failure mode was based on a manufacturing flaw or if the condition developed over time due to environmental effects such as moisture intrusion. At the end of this report period, the licensee's investigation team had not yet issued the final report of their findings.

c. Conclusions

On June 5, 1998, the plant experienced a negative rate reactor trip as the result of a dropped control rod (G7). The licensee assigned a root cause investigation team; however, a final report had not been issued.

E1.2 Root Cause of 15A FWH Tube Side Relief Lift

a. Inspection Scope (71707, 93702)

On June 5, 1998, the plant experienced an automatic reactor trip that resulted in an unexpected lift of the 15A FWH tube side relief valve. The inspectors assessed the licensee's investigation team review of the root cause for the unexpected event.

b. Observations and Findings

The licensee's initial root cause identification of the FWH tube side relief lift after the reactor trip was inconclusive. The licensee wrote a non-conformance report and identified that the relief lifted at the expected pressure setpoint. The licensee verified that all FWH system components mechanically worked as designed. However, the system engineer identified the condensate pump and MFP pressure was higher than indicated on the characteristic pump pressure curves. The system engineer identified the impellers had been modified which could have resulted in the pump curve inaccuracy and inappropriate relief valve setpoint. The system engineer further identified that a design change may be required for changing the FWH relief setpoint based on the new pump curves. At the end of this report period, the licensee's investigation team had not yet issued the final report of their findings.

c. Conclusions

On June 5, 1998, the plant experienced an automatic reactor trip that resulted in an unexpected lift of the 15A FWH tube side relief valve. The licensee assigned a root cause investigation team; however, a final report had not been issued.

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 June 12, 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

<u>Licensee</u>

K. Albrecht, General Superintendent Engineering, Electrical/Instrumentation & Controls
T. Amundson, General Superintendent Engineering, Mechanical
T. Breene, Superintendent Nuclear Engineering
J. Hill, Manager Quality Services
M. Ladd, Training Process Manager
G. Lenertz, General Superintendent Plant Maintenance
R. Lindsey, General Superintendent Safety Assessment
T. Silverberg, General Superintendent Plant Operations
J. Sorensen, Plant Manager

INSPECTION PROCEDURES USED

IP 71707: Plant Operations
IP 93702: Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/98010-01 50-306/98010-01	VIO	Inadequate procedure for dumping steam with steam generator power operated relief valves.

Closed

None.

Discussed

None.

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AWI	Administrative Work Instruction
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EOP	Emergency Operating Procedure
ERCS	Emergency Response Computer System
°F	Degrees Fahrenheit
FWH	Feedwater Heater
gpm	Gallons Per Minute
IP	Inspection Procedure
LER	Licensee Event Report
LRO	Lead Reactor Operator
MDAFW	Motor Driven Auxiliary Feedwater
MFP	Main Feedwater Pump
MSIV	Main Steam Isolation Valve
NR	Narrow Range
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
PORV	Power Operated Relief Valves
PRZR	Pressurizer
psig	Pounds Per Square Inch-Gauge
RCS	Reactor Coolant System
RO	Reactor Operator
SG	Steam Generator
SM	Shift Manager
SS	Shift Supervisor
STA	Shift Technical Advisor
SWI	Section Work Instruction
TB	Turbine Building
TDAFW	Turbine Driven Auxiliary Feedwater
T_{avg}	Average Reactor Coolant System Temperature
VIO	Violation

LIST OF DOCUMENTS REVIEWED

Procedure #	Revision #	Title
EOP 1E-0	Revision 17	Reactor Trip Or Safety Injection
1ES-0.1	Rev 13	Reactor Trip Recovery
1C1.3	Rev 40	Unit 1 Shutdown
SWI O-24	Rev 4	Operation Section Communications
5AWI 3.1.2	Rev 8	Shift Manager Program
SWI 0-10	Rev 30	Operation Manual Usage
2ES-0.1	Rev 12	Reactor Trip Recovery