U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No:	50-263/98015(DRP)
Licensee:	Northern States Power Company
Facility:	Monticello Nuclear Generating Station
Location:	2807 West Highway 75 Monticello, MN 55362
Dates:	August 31 through October 14, 1998
Inspectors:	S. Ray, Acting Senior Resident Inspector D. Wrona, Resident Inspector P. Krohn, Acting Senior Resident Inspector, Prairie Island
Approved by:	A. Vegel, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Monticello Nuclear Generating Station
Inspection Report 50-263/98015(DRP)

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

Operations

- Three examples of excellent system awareness were noted. An operator identified a very small leak in the body of a high pressure coolant injection steam line drain valve, a system engineer noticed that a standby liquid control relief valve appeared to lift at too low of a pressure, and a system engineer noticed an unusual response in the electrical pressure regulating system. In all instances, the licensee made conservative operability decisions when degraded equipment conditions were identified. (Sections O1.1 and 01.4)

- Operations personnel responded promptly to the isolation of the steam jet air ejector suction valves and the loss of both recombiner trains. Shift management proactively decided to manually trip the reactor. (Section O1.2)

- Shift management conservatively decided to delay reactor startup after a manual scram to investigate and repair an instrument air leak. The startup was conducted in a controlled and professional manner. (Section O1.3)

- The licensee began its power ascension test program. Operations personnel conducted testing in a controlled manner and held informative pre-test briefings. A system engineer identified an unusual response in the main turbine pressure regulating system and the licensee took conservative action to delay the testing until the cause of the unexpected response was determined. (Section O1.4)

- Minor problems identified by the inspectors during system walkdowns had been previously identified by the licensee. The licensee has taken action to correct these concerns. Two equipment issues identified at other plants were evaluated for applicability to Monticello. No concerns were identified by the inspectors. (Section O2.1)

Maintenance

- In general, the observed maintenance and surveillance activities, which involved systems or components such as emergency diesel generators and control rod drives, were conducted in accordance with procedures and in a professional manner. Engineering staff provided excellent support to the maintenance staff. (Section M1.1)

- The licensee's investigation team was thorough and aggressive, and performed an effective root cause investigation of the offgas system problems. The conclusions reached were reasonable. Maintenance personnel corrected equipment deficiencies identified during the investigation. (Section M2.1)

- The assessment and repair of a pinhole leak on a high pressure coolant injection system steam inlet line drain control valve was aggressively pursued by the maintenance and engineering departments. No similar problems were identified with other steam-line drain valves. (Section M2.2)

Engineering

- Engineering personnel support to operations and maintenance activities was appropriate during this inspection period. A safety review performed by engineering personnel for replacement of a high pressure coolant injection valve was reviewed by the inspectors, who identified no concerns. (Section E1.1)

- The safety review for a proposed modification to the condensate storage tank level detectors was considered weak because the review did not address the loss of condensate storage tank level instrument independence. (Section E1.2)

Plant Support

- Routine observations were conducted of radiological protection and chemistry controls, security and safeguards activities, and fire protection facilities and equipment. No concerns were identified. (Sections R1, S1, and F2)

Report Details

Summary of Plant Status

The unit operated at full power until September 9, 1998, when the unit was manually tripped due to problems in the offgas recombiner system. The plant was restarted on September 15, 1998, and reached full power on September 16. The unit was taken to about 75 percent power on October 3, 1998, for routine turbine valve testing and returned to full power on October 4. The unit operated at various power levels between 85 and 100 percent for testing associated with a power rerate from October 8, 1998, to the end of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (Inspection Procedure (IP) 71707)

The inspectors conducted frequent reviews of ongoing plant operations, including control room evolutions, shift turnovers, and operator rounds. The inspectors also reviewed control room logbooks and operability determinations. Updated Safety Analysis Report (USAR) Section 13, "Plant Operations," was reviewed as part of the inspection.

b. Observations and Findings

- The plant was operated in a controlled and deliberate manner. Specific events and noteworthy observations are detailed in the sections below. Operator performance during routine operations and surveillance test activities was good. Operator turnovers were conducted in accordance with procedures. Operators were knowledgeable of current and planned activities and acted in a professional manner.

- During this inspection period, actions were initiated to develop and promulgate management expectations regarding activities near the control panels such as eating and the wearing of hardhats. The general superintendent of operations issued a letter to the shift managers and other affected supervisors establishing policies that hardhats, food, and drinks were not to be allowed near the control panels. Operations personnel were working on an administrative work instruction (AWI) to proceduralize these policies and quality services personnel were developing a checklist that included these expectations for use during their observations of routine control room activities.

- During planned maintenance to check packing leakage on a high pressure coolant injection (HPCI) steam line drain valve on September 21, 1998, an operator discovered a pinhole leak on the HPCI drain line bypass valve,

CV-2043. Though the HPCI system remained functional, the licensee conservatively declared CV-2043 inoperable which led to declaring the HPCI system inoperable. The inspectors contacted the system engineer and observed the location of the pinhole leak before CV-2043 was isolated and repaired. The pinhole leak was very small and not easily seen. The operator who discovered the pinhole leak demonstrated excellent awareness and a good questioning attitude.

The licensee considered the impact of the HPCI system being declared inoperable in terms of its probabilistic risk assessment study (Monticello Nuclear Generating Plant Individual Plant Examination NSPNAD-92003, Revision 0) and previously scheduled work. While some planned maintenance and surveillance activities were put on hold pending return of the HPCI system, work on the13 emergency diesel generator (EDG) was allowed to proceed. The revised core damage frequency with both the HPCI system and 13 EDG inoperable was 3.9×10^{-5} per year. The nominal plant core damage frequency was approximately 1.95×10^{-5} per year. The licensee aggressively pursued repair of CV-2043 and replaced the valve. This work is discussed in Section M2.2. The HPCI system was subsequently returned to service on September 25, 1998.

The inspectors attended a daily status meeting on September 3, 1998. During the meeting, a system engineer stated that the 11 standby liquid control (SLC) pump discharge relief valve lifted during a routine pump surveillance at about 1310 pounds per square inch - gauge (psig). The setpoint of the relief valve was required to be between 1350 and 1450 psig in accordance with Technical Specification (TS) 4.4.A.2.c. TS 4.4.A.1 required that the SLC system be capable of suppling flow against a reactor coolant system head of 1275 psig, so, even if the relief was lifting at 1310 psig, the system should have been able to perform its design function. The inspectors noted that an excellent discussion ensued among plant management, the shift manager, maintenance and scheduling supervisors, and engineering personnel regarding whether the SLC pump should be considered operable.

Although it was apparent that the system could still meet its design basis requirements, there was a question regarding whether the relief valve met American Society of Mechanical Engineers (ASME) Section XI requirements, and whether the valve setpoint was not within the TS limits. As an interim measure, licensee management decided to consider the 11 SLC pump inoperable and tasked the staff with gathering more information for a meeting a few hours later. The shift manager concurred with the decision and immediately informed the control room of the decision. The inspectors considered the licensee decision to consider the 11 SLC pump inoperable until further information was gathered and evaluated to be an example of a conservative operating philosophy.

Later the same day, the licensee isolated the relief valve, removed it from the system, bench tested it (and found that the setpoint was actually about 1300 psig), adjusted the setpoint, and reinstalled the valve. Within about

17 hours of the original discussion, the system had been completely restored and tested, and the pump declared operable. The licensee's response to the issue was considered an example of excellent cooperation between operators, engineers, and maintenance personnel to quickly resolve problem with a safety-related component.

c. Conclusions

Two examples of excellent system awareness were noted. In one case, an operator identified a very small leak in the body of a HPCI steam line drain valve. In the other case, a system engineer noticed that a SLC relief valve appeared to lift below the required setpoint. In both cases, the licensee made conservative operability decisions and promptly resolved the equipment problems.

O1.2 Manual Reactor Trip Because of Offgas System Problems

a. Inspection Scope (IPs 71707 and 93702)

On September 9, 1998, at about 5:06 a.m., control room annunciators indicated that both offgas recombiner trains had tripped and that the suction valves for the steam jet air ejectors (SJAE) had closed. The operators initiated a rapid power reduction from full power, and at about 5:31 a.m., manually tripped the reactor from approximately 30 percent power.

The inspectors reviewed the sequence-of-events recorder, various strip charts, computer alarm printouts, control room log books, and procedures. The inspectors also discussed the event with the involved operations personnel. The root cause of the event is discussed in Section M2.1.

b. Observations and Findings

The inspectors noted that when the recombiner trains tripped and the SJAE suction valves closed, operators responded properly by initiating a rapid power reduction. When operators verified that a valid SJAE automatic isolation signal existed, they determined that the SJAE suction valves could only be opened after reactor power was reduced below 5 percent power. Since no apparent means of removing offgas from the condenser existed, and condenser vacuum was decreasing toward the automatic trip setpoint, shift management decided to manually trip the reactor.

All systems responded as expected to the reactor scram. As anticipated, the reactor vessel water level decreased to about 7 inches and resulted in a Containment Group II and Group III isolation. Reactor water level quickly returned to normal by use of the condensate and feedwater systems and the operators reset the reactor scram at about 5:42 a.m. Operators then proceeded to take the plant to cold shutdown.

c. Conclusions

Operations personnel responded promptly to the isolation of the SJAE suction valves and loss of both recombiner trains. Shift management proactively decided to manually trip the reactor.

O1.3 Reactor Startup Following Repairs to Offgas System

a. Inspection Scope (IP 71707)

The inspectors observed portions of the preparations for and conduct of the reactor startup after repairs were completed on the offgas system. The inspectors also reviewed Operations Manual Section C.1, "Startup Procedure," Revision 20.

b. Observations and Findings

While the plant operators were making preparations for unit startup, an operator in the reactor building noted that the instrument air flow to the drywell had increased since previous rounds. The flow was within acceptance bands specified on the round sheets; however, since the increased flow was not expected, the operator notified shift management. Shift management conservatively decided to delay the reactor startup to investigate the increased flow. The investigation revealed that there was an instrument air leak in the drywell from a regulator for the 11 recirculation pump seal. The licensee then de-inerted and entered the drywell to repair the regulator. Once repairs were completed, the operators commenced the reactor startup on September 15, 1998, and returned the unit to 100 percent power on September 16, 1998. The shift manager maintained command and control of the startup. Annunciator response and communications were conducted in a clear and professional manner. Shift supervision conservatively decided to stop the startup at the end of a rod sequence step as a convenient point to conduct shift turnover.

c. Conclusions

An operator in the reactor building with a good questioning attitude noted an increase in nitrogen flow to the drywell. Shift management conservatively decided to delay the reactor startup after a manual scram while the leak that caused the increased flow was repaired. The startup was conducted in a controlled and professional manner.

O1.4 Rerate Power Ascension Testing Program

a. Inspection Scope (IP 71707)

During this inspection period, the NRC approved License Amendment No. 102 which changed the maximum reactor core thermal power level specified in the Facility Operating License from 1670 megawatts-thermal (MWt) to 1775 MWt. The licensee commenced testing in accordance with Procedure 8303, "Prerequisites and Power Ascension Testing Control Procedure," Revision 0. Procedure 8303 controls the power

ascension from 1670 MWt to the new license limit of 1775 MWt. The inspectors attended pre-evolution briefings and observed portions of the power ascension testing.

b. Observations and Findings

On October 8, 1998, operations personnel reduced reactor power to approximately 1503 MWt to perform system dynamic testing, core thermal performance monitoring, and plant equipment performance data monitoring. Operations and engineering personnel conducted informative and detailed pre-evolution briefings. Testing was conducted in a controlled and deliberate manner. During dynamic testing of the main turbine electrical pressure regulator (EPR), system response was within the established acceptance criteria, but was not the response that was expected by the licensee. The licensee conservatively decided to delay pressure regulator dynamic testing. Operators returned the unit to approximately 1670 MWt. The licensee was in the process of investigating the cause of unexpected the EPR.

On October 13, 1998, the licensee reduced power to approximately 1418 MWt to perform Procedure 1076, "Reactor Dynamics Test Procedure," Revision 7, to test the EPR and mechanical pressure regulator (MPR) at a power where the pressure regulators previously responded as expected. Response of the EPR and MPR was stable; however, there was a slight oscillation during EPR testing. The licensee decided to reperform testing of the EPR and MPR in accordance with Procedure 8303. During EPR testing oscillations were again observed. The licensee returned the unit to 1670 MWt and was continuing to investigate the EPR.

The inspectors identified that during performance of Procedure 1076 an operator performed a step that changed reactor pressure using the EPR test switch. In accordance with Procedure 1076, this step was assigned to be performed by an engineer. The licensee had previously processed a temporary change for a similar step in Procedure 8303 to identify that an operator should perform the step. During a briefing for Procedure 1076, it was decided that an operator would perform the step. Although the licensee identified that an operator would perform the step, a procedure change was not processed. Since changing reactor pressure affects reactivity, it was appropriate to have an operator perform the step. The failure to adequately identify that an operator should operate the EPR test switch in Procedure 1076 is considered a minor violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which requires that activities affecting be prescribed by documented instructions or procedures, and is not subject to formal enforcement action. The licensee has processed Form 3087, "Document Change, Hold and Comment Form," and a temporary change for Procedure 1076 to resolve this concern.

c. Conclusions

The licensee began its power ascension test program. Operations personnel conducted testing in a controlled manner and held informative pre-test briefings. The system engineer identified an unusual response in the EPR system and the licensee took conservative action to delay the testing until the cause of the unexpected EPR response

was determined. informative briefings were observed. A minor violation for an inadequate procedure was identified.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns

a. Inspection Scope (IP 71707)

The inspectors used the licensee's risk analysis to aid in the determination of which safety-related systems to walk down and selected the following systems:

- Emergency diesel generator emergency service water (EDG-ESW)
- Scram inlet and outlet valves
- Standby gas treatment system filtration units
- Control room emergency filtration train filtration units
- Residual heat removal service water (RHRSW)

b. Observations and Findings

- No operability concerns were identified during the EDG-ESW and RHRSW system walkdowns. Minor material condition issues identified by the inspectors were previously identified by the licensee and entered into the work order (WO) system.

- in response to findings at other plants, the inspectors walked down the control rod drive hydraulic control units to determine if the wires going to the directional control valve solenoids could interfere with operation of the scram inlet or outlet valves or their associated position indicating switches. The inspectors noted that all of the directional control valve cables were of uniform length and were too short to reach the scram inlet or outlet valves. The inspectors discussed directional control valve maintenance with the electrical maintenance supervisor and a lead electrician. They stated that there was no specific procedural instruction to ensure that the cables did not interfere with the scram valves, but that it was within the "skill-of-the-craft" to use cables that were not excessively long. Based on the observed condition of the system, the inspectors had no concerns with this issue.

- In response to an event at another facility (NRC Event Notification 34788), the inspectors walked down the safety-related air filtration units to determine if they contained any paper filter elements that could become water soaked and plug other filters or fans in the units. For the standby gas treatment system filtration units, the inspectors determined by inspection that the filter elements were metallic and not subject to the failure mode of concern. For the control room

emergency filtration train units, the filter media was not visible without opening the unit, so the inspectors discussed the filter element construction with the system engineer. The engineer provided information from the appropriate vendor catalog. All filters were either metallic or fiberglass with metallic frames. Based on the filter element construction, the inspectors had no concerns with this issue.

c. Conclusions

Minor material condition concerns identified by the inspectors were previously identified by the licensee. The licensee has taken action to correct these concerns. The inspectors evaluated two equipment issues which affected other plants and did not identify any concerns.

O2.2 Tour of Generally Inaccessible Areas (IP 71707)

While the reactor was shutdown to make repairs to the offgas system, the inspectors toured areas that are typically inaccessible during power operation. The areas toured included the condenser room, air ejector room, recombiner room, and turbine deck. No concerns were noted.

O8 Miscellaneous Operations Issues (IP 92901)

O8.1 (Closed) Unresolved Item (URI) 50-263/97003-03(DRP): Modified Surveillance Frequency with Change in Shift Hours. This URI involved the licensee's change from 8-hour to 12-hour operating shifts and the resultant change in frequency for certain "shiftly" surveillances from three times per day to twice per day. The inspectors were concerned that the change in shift length may have required prior NRC approval in accordance with 10 CFR 50.59 because it may have involved a change to the TSs.

The NRC Office of Nuclear Reactor Regulation determined that, since the length of a shift was not specifically defined in the TS, no violation of NRC requirements had occurred. In addition, the licensee submitted a license amendment request (LAR) dated August 15, 1996, and supplemented on March 19, 1998, and October 12, 1998, clarifying the meaning of "shiftly."

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (IPs 62707 and IP 61726)

The inspectors observed all or portions of selected maintenance and surveillance activities. As practical, the inspectors selected maintenance and surveillance activities associated with systems that were risk significant. Included in the inspection was a

review of the surveillance procedures or WOs listed, as well as the appropriate USAR sections pertaining to activities inspected.

b. Observations and Findings

In general, the inspectors observed that the work associated with these activities was conducted in a professional and thorough manner. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever specified in procedure. When applicable, appropriate radiation control and security measures were in-place.

The following maintenance and surveillance activities were observed. Specific concerns or observations with some of the activities are provided in other sections of this report.

- WO 9802991, Air Leak on Valve Actuator (AO-1084B, SJAE Isolation Valve)
- WO 9802987, Inspect Pipe Chase Below Recombiner Pump Room
- WO 9802944, Perform Preventative Maintenance on Condensate Storage Tank Level Instrument CST-3
- WO 9802811, Inspect 12 EDG Cylinders
- WO 9802806, EDG ESW Pump #12 Will Not Run
- WO 9803061, 11 RHRSW Pump Differential Pressure in the Alert Range
- WO 9803063, Determinate/Reterminate 11 RHRSW to Support WO 9803061
- Surveillance Test 0010, "Reactor Manual Scram Functional Test," Revision 11
- Surveillance Test 0074, "Control Rod Drive Exercise Test," Revision 24
- Surveillance Test 0075, "Control Rod Drive Coupling Test," Revision 7
- Surveillance Test 0187-2, "12 Emergency Diesel Generator/12 Emergency Service Water Pump System Tests," Revision 27
- Surveillance Test 8303, "Prerequisites and Power Ascension Testing Control Procedure," Revision 0
- Surveillance Test 1076, "Reactor Dynamics Test Procedure," Revision 7

c. Conclusions

In general, the observed maintenance and surveillance activities, which involved systems or components such as the EDGs and control rod drives, were conducted in accordance with procedures and in a professional manner. An exception was discussed in Section O1.4 where an incorrect procedure was not corrected before performance. Engineering staff provided excellent support to the maintenance staff.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Offgas System Repairs

a. Inspection Scope (IP 62707)

As discussed in Section O1.2, while the unit was at full power, both offgas recombiner trains tripped and the SJAE suction valves isolated automatically. The inspectors reviewed the licensee's evaluation and various strip charts, and interviewed operators and engineers to independently verify the cause of these events.

b. Observations and Findings

The licensee created a team composed of operators, system engineers, and safety assessment staff members to determine the cause of the event. System engineers walked down portions of the SJAE and offgas piping to identify any signs of damage. The inspectors independently walked down accessible sections of this piping. The only damaged identified was heat damage to the paint on the valve body of PCV-7496B (offgas bypass return to condenser). Other piping problems not related to this event were identified, such as weld flaws and some incomplete reinforcement welds. Repairs were completed prior to system startup.

The licensee conducted an investigation to determine the cause of the heat damage on PCV-7496B. Included in this investigation was a search for catalyst in the offgas piping upstream of the recombiners. Visual inspection of the recombiner catalyst bed retention screen and various piping openings along with chemical analyses of pipe scrapings showed no evidence of catalyst. However, disassembly of PCV-7496B identified seat damage. The licensee determined that the most probable cause was that the seat leakage ignited, heating the valve body high enough for spontaneous ignition of hydrogen and oxygen in the offgas system upstream of recombiners which resulted in a pressure wave that caused the recombiners to trip and the SJAE suction valves to isolate. The inspectors had no concerns with the licensee's conclusions.

The licensee installed temporary temperature indicating equipment on the offgas lines to capture data, should a similar event occur in the future. The licensee submitted Licensee Event Report (LER) 50-263/98004, "Manual Scram Inserted Following Pressure Transient Closes Air Ejector Suction Isolation Valves and Trips Offgas Recombiners," Revision 0. This LER is discussed in Section M8.2.

c. Conclusions

The licensee's investigation team was thorough and aggressive, and performed an effective root cause investigation. The conclusions reached were reasonable. Maintenance personnel corrected equipment deficiencies identified during the investigation.

M2.2 Repair of Leak on HPCI Drain Line Bypass Valve

a. Inspection Scope (IP 62707)

The inspectors observed the maintenance activities associated with the repair of a pinhole leak on the valve body of CV-2043, a HPCI inlet steam line drain bypass control valve.

b. Observations and Findings

On September 21, 1998, during planned maintenance to check a packing leak, an operator discovered a through-wall pinhole leak on the HPCI system steam inlet drain line bypass control valve, CV-2043. The licensee declared CV-2043 inoperable which led to declaring the HPCI system inoperable. The NRC was notified in accordance with 10 CFR 50.72 and a 14-day limiting condition for operation was entered as required by TS 3.5.A.3.g.

Prior to valve disassembly, the inspectors witnessed an ultrasonic test (UT) of the valve body. The test used a 5-megahertz, dual element, focused, 1/4-inch diameter transducer to measure the remaining wall thickness of the valve body. The transducer was calibrated on a 1-inch step wedge. The UT examiner's scanning technique was adequate and provided full coverage of the valve body. Although not precise in nature, the UT examination was adequate to confirm significant wall loss in a localized area of the valve body surrounding the pinhole leak.

Valve disassembly indicated that steam-cutting of the valve seat had occurred. This allowed a steam jet to erode the valve body resulting in the pinhole leak. The inspectors viewed the valve body internals and noted significant wall loss in the areas adjacent to the pinhole leak. The licensee concluded that weld repair was not feasible and replaced the entire valve. The HPCI system was retested and subsequently returned to service on September 25, 1998.

The inspectors reviewed Jumper Bypass Form 98-101; Safety Review Item 98-017, Revision 0, "Temporary Replacement of CV-2043 With a Manual Valve"; design change notice; weld repair records and weld procedures associated with replacing CV-2043. The inspectors also attended twice daily status meetings on CV-2043 and noted good coordination between the maintenance and engineering departments concerning the staging of work, resource utilization, locating replacement parts, and writing the necessary work orders and procedures.

The licensee also considered the broader implications of the pinhole leak on CV-2043 and examined other similar steam line drain valves. No evidence of damage was discovered.

c. Conclusions

An observant operator identified a HPCI system pinhole leak on a steam inlet line drain control valve. The assessment and repair of a pinhole leak was aggressively pursued

by the maintenance and engineering departments. No similar problems were identified with other steam-line drain valves.

M8 Miscellaneous Maintenance Issues (IPs 92902 and 92700)

M8.1 (Closed) Inspection Followup Item (IFI) 50-263/96012-03(DRP): Follow up on Quality Services Audit Regarding Post-Maintenance Testing (PMT). This purpose of this IFI was to follow up the licensee's actions to improve the quality of the PMT program. At the time the inspectors were concerned that a study by the licensee's quality services group completed in early 1996 indicated that 75 percent of the PMT documents reviewed did not comply with the AWI requirements.

Subsequently, aggressive action was taken to improve the PMT program. The AWI was revised to simplify and clarify the requirements, and increased attention was paid to PMTs by maintenance supervisors, engineers, and operations personnel. A followup study by quality services personnel in early 1997 indicated that AWI compliance issues had dropped from 75 percent to 23 percent with most of the problems being minor. However, compliance with the AWI was still not considered acceptable and improvement efforts continued.

The inspectors reviewed recent data tracked by the maintenance scheduling group regarding quality services findings on a wide variety of issues with maintenance work orders including PMTs. For the past three quarters of 1998, PMT problems have decreased from 2.2 percent to 1.3 percent to 0.8 percent of work orders reviewed. Most of the PMT errors were minor administrative issues. The licensee has achieved significant improvements in the PMT process. The inspectors had no additional concerns.

M8.2 (Closed) LER 50-263/98004, Revision 0: Manual Scram Inserted Following Pressure Transient Closes Air Ejector Suction Isolation Valves and Trips Offgas Recombiners. This event is discussed in Sections O1.2 and M2.1. The inspectors had no concerns.

III. Engineering

E1 Conduct of Engineering

E1.1 General Engineering Observations

a. Inspection Scope (IP 37551)

The inspectors reviewed engineering-related activities and observed engineering personnel involvement in resolving problems identified during maintenance, surveillance, and operations activities. Included in the inspection was a review of appropriate TSs and USAR sections.

b. Observations and Findings

In general, the inspectors determined that engineering support to maintenance, surveillance, and operations activities was appropriate. In addition, the inspectors reviewed Safety Review Item 98-017, "Temporary Replacement of CV-2043 with a Manual Valve," Revision 0. This safety review item is associated with the replacement of the HPCI inlet steam line drain bypass control valve discussed in Section M2.2. The inspectors had no concerns.

c. Conclusions

Engineering personnel support to operations and maintenance activities was appropriate during this inspection period. The inspectors reviewed a safety review item and had no concerns.

E1.2 Adequacy of Safety Review for a Proposed Modification to the Condensate Storage Tank (CST) Level Detectors

a. Inspection Scope (IP 92903)

In the process of closing the IFI discussed in Section E8.7 of this report, the inspectors reviewed Safety Review Item 97-008, "Condensate Storage Tank Level Setpoint For HPCI/RCIC [Reactor Core Isolation Cooling] Transfer and Related USAR Issues," Revision 0.

b. Observations and Findings

This issue was previously discussed in Inspection Report 50-263/97014(DRP), Section E2.2.b. The licensee identified that the TS did not allow HPCI and RCIC suctions to remain aligned to the CST during periods of single CST operation because one of the CST level detectors became inoperable. As a result, the licensee designed a modification to cross-tie the two CST level detectors to the single sensing line of the operable CST during those periods. Safety Review Item 97-008 was reviewed by the station onsite review committee and approved by the general superintendent of engineering on October 2, 1997, approving the modification.

The inspectors were concerned that the change could involve an unreviewed safety question, in accordance with 10 CFR 50.59, because the probability of failure of the HPCI system might increase when depending on non-independent switches for the transfer of HPCI suction on low CST level. If the single sensing line were to plug or freeze, the transfer function could become disabled and suction to the pump could be lost.

It should be noted that the licensee reviewed and approved the safety of the modification, but the modification was never actually performed because no periods of single CST operation were required in the ensuing year. The safety review item was considered weak because the review did not discuss the loss of CST level instrument independence and document whether that change could have led to an unreviewed

safety question. However, since the plant was not actually modified, no violation of NRC requirements occurred.

The licensee submitted a LAR dated November 26, 1997, which discussed raising the CST level setpoint and maintaining level switch redundancy during periods of single CST operation, but the request did not specifically discuss the loss of level switch independence during those periods.

The inspectors discussed their concerns with licensee engineering personnel, who acknowledged that the review did not adequately address the switch independence issue. However, they stated that leaving HPCI and RCIC suctions aligned to the CST rather than to the suppression pool during periods of single CST operation was still desirable from an overall safety standpoint because of the increased inventory of water available for reactor makeup and the higher quality of that water. The engineers agreed to take the following actions:

- issue a condition report to document the concern (Condition Report 98002617 was issued) and initiate the corrective action process, and

- submit a supplement to the LAR explaining the effect of loss of instrument independence along with the net safety benefit of maintaining the CST as a source of water for HPCI and RCIC during single CST operation.

The commitments above resolved the inspectors' concerns. The acceptability of connecting the level switches to the same sensing line will now be reviewed as part of the LAR, rather than as a change to the facility under 10 CFR 50.59.

c. Conclusions

The safety review for a proposed modification to the condensate storage tank level detectors was considered weak because the review did not address the loss of CST level instrument independence.

E8 Miscellaneous Engineering Issues (IPs 92700 and 92903)

E8.1 (Closed) IFI 50-263/96005-06(DRP): Follow-up on Testing HPCI and RCIC Systems at Low Pressure and Considering them Operable at High Pressure. The inspectors verified that the licensee's testing procedures for HPCI and RCIC met the applicable TS-surveillance requirements and ASME in service testing requirements. The systems were required to be operable before exceeding 150 psig reactor pressure. Therefore, the licensee had to be able to consider the systems operable based on low pressure testing. Subsequent testing at normal reactor pressure was also required by TSs and was completed as required.

E8.2 (Closed) IFI 50-263/96006-04(DRP): Review of Audit Results of the Nuclear Analysis and Design (NAD) organization. This IFI was initiated as a result of the inspectors' concern that the licensee had identified an adverse trend in personnel errors within activities conducted by the NAD organization, which has responsibility for core design.

The inspectors wanted to review the results of subsequent licensee efforts to audit NAD's performance.

The inspectors reviewed Quality Services Audit AG 1997-E-2 which, in part, audited NAD activities. The audit team noted significant improvements in the documentation of calculations and in the design verification process. Program strengths were identified in the training and qualifications area and the use of outside technical experts to perform an assessment of the reload analysis process. Several significant weaknesses were identified in administrative controls and the appropriate findings were issued. The administrative weaknesses did not affect the technical accuracy of the analyses reviewed. Overall, the audit characterized the area of nuclear core design as being effectively implemented.

The audit demonstrated that the licensee's quality services organization could conduct a through and critical audit of NAD. The next audit of NAD was scheduled for the first quarter of 1999.

E8.3 (Closed) LER 50-263/96014: Unqualified Electrical Splice Found in Train B of the Standby Gas Treatment System. This LER was previously discussed in Section M1.1 of Inspection Report 50-263/96012(DRP), and involved the licensee's finding of an unqualified splice in a junction box internal to ventilation ductwork. At the time of that inspection, the only remaining corrective action was for the licensee to review similar electrical boxes located internal to other system and inspect any such boxes for internal splices. The inspectors reviewed Condition Report 96002921 which documented the results of that inspection. No additional unqualified splices were found.

E8.4 (Closed) IFI 50-263/97002-05(DRP): Residual Heat Removal (RHR) room sump pump USAR statement discrepancy. This item pertained to a discrepancy in USAR Section 10.3.6.3.2, which incorrectly stated that the two sump pumps in each RHR corner room were powered from the same motor control center. The licensee has evaluated the proposed USAR change and was in the process of updating this section of the USAR. The failure to maintain an accurate description in the USAR, contrary to 10 CFR 50.71(e), did not have a material impact on safety or licensed activities. Therefore, this problem is classified as a violation of minor significance that is not subject to normal enforcement action.

E8.5 (Closed) LER 50-263/97010: Failure to Include Some Supports on the Reactor Head Vent Line in the ISI [inservice Inspection] Program in the 2nd 10-Year Interval Due to Inaccurate Drawings and Failure to Report This Event in a Timely Manner due to Personnel Error. This LER was submitted by the licensee on October 16, 1997, to report the identification that seven support hangers on the reactor head vent line were not included in the ISI program required by TS 4.15.A. The licensee determined that the line was operable and added the hangers to the ISI program. These corrective actions were reasonable.

As reported in the LER, two violations of NRC requirements occurred. One violation was the failure to include the supports in the inspection program required by TS 4.15.A during the 2nd 10-year ISI interval, and the other violation was the initial failure to report

the issue in accordance with 10 CFR 50.73, after the problem with the seven supports was identified in May 1997. The supports were ultimately determined to have been operable; however, the results of the licensee's new pipe stress analysis for the "as-built" configuration of the reactor head vent line showed that some areas could have exceeded code allowable stresses. The licensee performed a modification in the May 1997 outage to bring the pipe stresses into ASME Code compliance.

Since a section of piping attached to the reactor was in a condition where code allowable pipe stresses could have been exceeded since original plant construction, the issue of not including them in the inspection program was considered to be of more than minor safety significance. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV) of TS 4.15.A, which requires that ISI be performed of these supports, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-263/98015-01(DRP)). The initial failure to report the finding is considered a minor violation not subject to formal enforcement action.

For long term corrective actions, the licensee evaluated other piping to ensure that all supports were included in the ISI program, as required. Two additional supports were identified that were not in the program; they were subsequently added. Because these supports had been recently installed (1993), the time limit for conducting ISI of them had not expired, and thus TS 4.15.A had not been violated in this instance.

E8.6 (Closed) LER 50-263/97012: Condensate Storage Tank Low Level Suction Transfer Setpoint Did Not Provide Sufficient Submergence As The Result of a Design Deficiency; and

(Closed) URI 50-263/97014-03(DRP): Safety Significance of Continued Operation with One Condensate Storage Tank.

This issue was previously discussed in Inspection Report 50-263/97014(DRP), Section E2.2.b. It was unresolved pending the inspectors' review of the safety significance of the issue as discussed in the LER.

The licensee concluded that the existing CST low-level setpoint for automatic transfer of the HPCI and RCIC suction to the suppression pool was non-conservative, especially for operation with a single CST. In Inspection Report 50-263/97014(DRP), Section M1.2, the NRC considered the failure to transfer HPCI and RCIC suctions to the suppression pool during single CST operation as a Non-Cited Violation (NCV 50-263/97014-01). As discussed in the inspection report, in addition to the period of single CST operation that led to the discovery of the issue, a previous period from August 31 to November 13, 1995, was also identified where single CST operation had occurred. In that case, the CST level detectors should also have been considered inoperable, and the HPCI and RCIC system suctions should have been aligned to the suppression pool in accordance with TS Table 3.2.8. Therefore, the failure in 1995 to realign the HPCI and RCIC suctions to the suppression pool during single CST operation was a violation of TSs.

The inspectors reviewed plant operating records and determined that, during the period of single CST operation with the HPCI and RCIC suctions lined up to the CST, the

automatic depressurization system was always operable. Therefore, as discussed in the LER, the safety significance of the setpoint problem was low, as discussed in the LER, and that the corrective actions being taken were adequate. The 1997 event was already considered an NCV as discussed above. Therefore, the 1995 occurrence of the same configuration is considered part of the same NCV and not subject to additional enforcement action.

E8.7 (Closed) IFI 50-263/97014-04(DRP): Review of Proposed Modification for One CST Operation. This issue is discussed in Section E1.2 of this report.

E8.8 (Closed) URI 50-263/97018-04(DRP): USAR Table 7.6-2 Inconsistencies With Instrument Setpoint Information. This item was previously discussed in Section E2.1 of Inspection Report 50-263/97018. The licensee evaluated the issues in Condition Report 98000006. The inspectors had no further concerns.

IV. Plant Support

R1 Conduct of Radiological Protection and Chemistry Controls (IP 71750)

During normal resident inspection activities, routine observations were conducted in the area of radiation protection. The inspectors noted that effective radiological controls were established and that technicians provided adequate support during maintenance and surveillance activities. No concerns were noted.

S1 Conduct of Security and Safeguards Activities (IP 71750)

During normal resident inspection activities, routine observations were conducted in the area of security and safeguards activities. No concerns were noted.

F2 Status of Fire Protection Facilities and Equipment (IP 71750)

During normal resident inspection activities, routine observations were conducted in the area of fire protection. No concerns were noted.

V. Management Meetings

X1 Exit Meeting Summary

On October 14, 1998, the inspectors presented the inspection results to members of licensee management. 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

M. Hammer, Plant Manager
B. Day, General Superintendent Operations
K. Jepson, Superintendent, Chemistry & Environmental Protection
L. Nolan, General Superintendent Safety Assessment
E. Reilly, General Superintendent Maintenance
S. Hammer, Acting General Superintendent Engineering
A. Ward, Manager Quality Services
L. Wilkerson, Superintendent Security
J. Windschill, General Superintendent, Radiation Protection

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Plant Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-263/98015-01(DRP)	NCV	Failure to Include Some Supports on the Reactor Head Vent Line in the ISI Program

Closed

50-263/96005-06(DRP)	IFI	Follow up on Testing HPCI and RCIC Systems at Low Pressure and Considering Them Operable at High Pressure
50-263/96006-04(DRP)	IFI	Review of Audit Results of the NAD organization
50-263/96012-03(DRP)	IFI	Follow up on Quality Services Audit Regarding PMT
50-263/96014	LER	Unqualified Electrical Splice Found in Train B of the Standby Gas Treatment System
50-263/97002-05(DRP)	IFI	RHR Room Sump Pump USAR Statement Discrepancy
50-263/97003-03(DRP)	URI	Modified Surveillance Frequency with Change in Shift Hours
50-263/97010	LER	Failure to Include Some Supports on the Reactor Head Vent Line in the ISI Program in the 2nd 10-Year Interval Due to Inaccurate Drawings and Failure to Report This Event in a Timely Manner due to Personnel Error
50-263/97012	LER	Condensate Storage Tank Low Level Suction Transfer Setpoint Did Not Provide Sufficient Submergence As The Result of a Design Deficiency

50-263/97014-03(DRP)	URI	Safety Significance of Continued Operation with One Condensate Storage Tank
50-263/97014-04(DRP)	IFI	Operations Committee Members Approved Modification for One CST Operation
50-263/97018-04(DRP)	URI	USAR Table 7.6-2 Inconsistencies With Instrument Setpoint Information
50-263/98004	LER	Manual Scram Inserted Following Pressure Transient Closes Air Ejector Suction Isolation Valves and Trips Offgas Recombiners
50-263/98015-01(DRP)	NCV	Failure to Include Some Supports on the Reactor Head Vent Line in the ISI Program

Discussed

50-263/97014-01(DRP)	NCV	Failure to Realign the HPCI and RCIC Suction Valves to the Suppression Pool After Making One CST Level Channel Inoperable

LIST OF ACRONYMS USED

AWI	Administrative Work Instruction
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EPR	Electrical Pressure Regulator
ESW	Emergency Service Water
HPCI	High Pressure Coolant Injection
IFI	Inspection Followup Item
IP	Inspection Procedure
IR	Inspection Report
LAR	License Amendment Request
LER	Licensee Event Report
MPR	Mechanical Pressure Regulator
MWT	Megawatts-Thermal
NAD	Nuclear Analysis and Design
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NSP	Northern States Power
PDR	Public Document Room
PMT	Post-Maintenance Testing
psig	Pounds per Square Inch - Gauge
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic Testing
WO	Work Order

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