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Report No: 50-282/96-07, 50-306/96-07, 72-10/96-07

Licensee: Northern States Power Company

Facility: Prairie Island Nuclear Generating Plant

Location: 1717 Wakonade Drive East
Welch, MN 55089

Dates: May 25 - July 9, 1996

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EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Units 1 & 2
NRC Inspection Report 50-282/96-07, 50-306/96-07, 72-10/96-07

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional operator license examiner, the lead engineering assessment person, and an inservice inspection specialist.

Operations

- Response to a dual unit trip from full power and a partial loss of offsite power was rapid, thorough, and effective. Operators effectively used the proper procedures to stabilize the plant and conduct recovery actions. All operating evolutions were conducted in a calm, deliberate, and prudent manner. (Section O1.2)

- Plant equipment including all four emergency diesel generators responded as designed to the trips and loss of power indicating excellent material condition. (Sections O1.2 and O2.1)

- Two procedural deficiencies were noted during operator license exams. The procedures were revised to correct the problems. This deficiency is being treated as a non-cited violation. (Section O3.1)

Maintenance

- All maintenance and surveillance activities observed were professional and thorough. (Section M1.1)

- Deviations from the American Society of Mechanical Engineers (ASME) Code Section XI requirements for the inservice inspection (ISI) plan and ultrasonic testing requirements for dissimilar metal welds, indicated that opportunities exist for improvement in oversight of the ISI program. (Section M3.1)

Engineering

- One apparent violation was identified involving a design control issue. Engineers did not consider all potential sizes of secondary side pipe ruptures during development, implementation, and review of design modification 80L579 in 1982. PINGP's design controls did not assure that the AFW system design basis was appropriately translated when specifying the AFW pump low pressure switch trip setpoint. As a result of this design control issue, both unit's AFW pumps were effected and may have been inoperable if they were not protected from pump run-out damage for all postulated secondary system line break sizes. Corrective actions taken upon identification of this issue, in May 1996 by a licensee self assessment initiative, were thorough and aggressive. No Notice of Violation is currently being issued pending further NRC management consideration of this violation. (Section E1.1)

- The results of the licensee's inspection of the intake line indicated there may have been some flow degradation due to silting. (Section E2.1)

- The decision to install a replacement stem without verification of material flaws via nondestructive testing marred an otherwise conservative approach in corrective action for the feedwater regulating valve failure. (Section E2.2)

- The inspectors noted an editorial discrepancy in the Updated Safety Analysis Report regarding the location of the hydrogen monitor system data acquisition and control assemblies. (Section E2.3)

- Several weaknesses were noted in the events resulting in a violation of Technical Specifications for having containment hydrogen monitors inoperable. Those included: (Section E8.1)

    * Performing work outside the scope of a work order and then failing to document all the work performed.

    * Failure to specify post-maintenance testing.

    * Filling calibration gas bottles to a significantly higher pressure than that specified by procedure.

    * Failure to perform an adequate review and document a configuration change to pressure regulator settings.

    * Design control and configuration management procedures which did not address control of pressure regulator settings.

- The licensee's self-assessment of its safety evaluation program was aggressive and thorough. (Section E8.2)

Plant Support

- The NRC identified a failure to submit a report required by Technical Specifications. The failure is being treated as a Non-Cited Violation. (Section R3.1)

- The licensee properly classified and reported the dual unit trip and loss of offsite power event. They conservatively activated the emergency response organizations, and used them to provide excellent support to the operators for recovery. Lessons learned from exercises and drills were effectively used in this response to an actual event. (Section P1.1)

Report Details

Summary of Plant Status

Both units operated at full power until June 29, 1996, when severe winds caused damage to offsite power lines and both units tripped simultaneously. Unit 1 was taken critical on June 30 and unit 2 on July 1. Both unit's generators were placed on line on July 2.

During this period the fourth dry cask, loaded with 40 spent fuel assemblies, was moved to the Independent Spent Fuel Storage Installation (ISFSI). In addition, the fifth dry cask was inspected and moved to the ISFSI empty. The licensee intended to move it back into the plant and load it at a later date.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of plant operations. In general, the conduct of operations was acceptable; specific events and noteworthy observations are detailed in the sections below.

O1.2 Partial Loss of Offsite Power and Dual Unit Trip

a. Inspection Scope (93702)

At 2:29 PM on June 29, 1996, a severe wind storm in the area caused damage to several offsite power lines, a partial loss of offsite power, and simultaneous reactor trips from 100 percent power on both units. The inspectors responded to the site and monitored the licensee's response to the event and recovery actions.

b. Observations and Findings

Sequence of Events

Accurate reconstruction of the events was hampered somewhat by a lack of data. The electrical disturbances caused a loss of the emergency response computer system on unit 1 and a loss of the balance of plant annunciator recorder on unit 2. The following is a sequence that represented the best information available at end of the inspection period.

- 2:18 PM Blue Lake 345 KV line disturbance caused switchyard breakers 8H14 and 8H15 to open.

- 2:29 PM Red Rock 1 345 KV line disturbance caused switchyard breakers 8H17 and 8H18 to open.

- 2:29 PM Red Rock 2 345 KV line disturbance caused switchyard breakers 8H7 and 8H8 to open. That completely opened the ring bus, isolating both unit's generators from the remaining offsite power lines. Generator loads decreased drastically and turbine speeds increased.

- 2:29 PM Turbine governor valves closed due to turbine overspeed of 103 percent. Reactor cold leg temperature increased rapidly toward hot leg temperature because heat was not being removed by the steam generators. The warmer water being returned to the reactor downcomer area resulted in decreased neutron attenuation and higher indicated reactor power.

- 2:29 PM Indicated reactor power increased to about 102.7 percent in about one second. That caused a reactor trip on both units due to high positive rate on nuclear instrumentation. Actual reactor power never increased.

- 2:29 PM Both unit's turbines tripped due to the reactor trip signal. Then the turbines had reached speeds of 109.7 percent and would soon have tripped on overspeed. That also would have caused a reactor trip if the positive power rate had not.

- 2:30 PM Both unit's generator output breakers tripped 30 seconds after the turbine trips as expected. That resulted in a complete loss of AC power to unit 2, a trip of reactor coolant pumps, and startup of the D5 and D6 emergency diesel generators (EDGs).

- 2:30 PM There were two remaining offsite lines (the 345 KV Byron line and the 161 KV Spring Creek line) feeding switchyard bus 2 and the unit 1 buses. However, there was little nearby generating capacity on those lines. They also experienced degraded voltage conditions resulting in tripping of the unit 1 reactor coolant pumps, and starting of the D1 and D2 EDGs. Several other nonsafeguards loads on unit 1 also tripped due to the degraded voltage.

Stable Condition

Both plants were stabilized in the hot shutdown condition with natural circulation of reactor coolant. All control rods were verified fully inserted. The EDGs powered all the safeguards buses and appropriate loads. Unit 1 non-safeguards buses remained powered from offsite power through the 1R auxiliary transformer from switchyard bus 2. Unit 2 nonsafeguards buses were not powered. Decay heat was removed by use of the steam dumps and auxiliary feedwater (AFW) pumps. Later operators secured the turbine-driven AFW pumps and steam generator levels were

maintained with the motor-driven AFW pumps alone. Later operators also closed the main steam isolation valves to help maintain hot shutdown conditions. The plants were maintained in those conditions until recovery actions were successful in restoring some offsite power.

Licensee Response and Recovery Actions

At 3:05 PM the shift supervisor declared a Notification of Unusual Event (NUE) and elected to call out the emergency response organization (ERO) to help support the recovery. Notifications were made to the ERO and the NRC inspectors. The inspectors responded to the site and monitored the recovery actions from the technical support center and control room. The licensee notified the NRC via the emergency notification system at 3:41 PM. Major recovery actions were as follows:

June 29

- 6:00 PM Bought power from another utility to raise the voltage on the remaining 345 KV (Byron) line to enable starting of reactor coolant pumps. Also transferred the 2R auxiliary transformer from dead switchyard bus 1 to live switchyard bus 2. Thus offsite power was restored to the unit 2 nonsafeguards buses.

- 7:53 PM Started one of two reactor coolant pumps on Unit 1.

- 8:28 PM Started one of two reactor coolant pumps on Unit 2.

- 9:00 PM Declared one normal offsite power source to each unit completely operable through the 1R and 2R auxiliary transformers.

June 30

- 2:55 AM The 345 KV Blue Lake line was repaired and connected to the switchyard. Damage was reported to have consisted of one phase down on one tower. Also about that time the licensee completed lineups for the second normal path of offsite power to the safeguards buses through the cooling tower transformers.

- 10:00 AM Completed transferring power to the safeguards buses from the EDGs to offsite power and secured the EDGs.

- 10:35 AM Exited from the NUE. Three of five offsite power lines to the switchyard were operable and two independent paths from the switchyard to the safeguards buses were available for each unit. Switchyard bus 1 was still out of service.

- 11:57 AM Started the second reactor coolant pump on unit 1.

- 1:10 PM Started the second reactor coolant pump on unit 2.
- 6:07 PM Switchyard bus 1 was restored. The ring bus was established.
- 8:20 PM Commenced a startup of unit 1.
- 11:01 PM Unit 1 was made critical.

July 1

- 10:40 AM Commenced a startup of unit 2.
- 12:14 PM Unit 2 was made critical.
- 3:54 PM The unit 1 generator was placed on the grid.
- 4:29 PM Experienced problems with exciter bearing vibrations and the electro-hydraulic turbine control system. The unit 1 generator was manually tripped.

July 2

- 12:20 AM The unit 2 generator was placed on the grid.
- 3:39 AM The unit 1 generator was placed on the grid. Total power output from the site was limited to 750 MW due to grid stability considerations with both the Red Rock lines still out of service.

July 4

- 9:50 PM The Red Rock 2 345 KV line was restored. Damage was reported to have consisted of five wooden tower structures damaged. Power output restrictions were lifted from the site.

July 8

- 7:51 PM The Red Rock 1 345 KV line was restored. Damage was reported to have consisted of seven wooden tower structures damaged.

c. Conclusions

The plants responded as designed to the event. All reactor, turbine, generator, and electrical protection systems functioned as expected. All four EDGs worked properly and powered their respective safeguards buses for extended periods without major problems. In addition, the security diesel generator and cooling water pump diesels functioned as expected. Natural circulation of reactor coolant with AFW pumps and

steam dumps effectively removed the decay heat from extended full power operations. The licensee effectively dealt with some minor equipment problems during the event and there was never a significant threat to public health and safety.

Operators effectively used the proper procedures to stabilize the plant and conduct recovery actions. All operating evolutions were conducted in a calm, deliberate, and prudent manner. No precipitous actions were taken in an attempt to speed up recovery. Technical Specification limiting conditions for operations were conservatively implemented and followed. The ERO provided excellent support to operations as discussed in Section P1.1 of this report.

The event was considered highly unusual and was a significant challenge to the plant and its operators. However, the effective operator training program, outstanding material condition of the plant equipment, and excellent support by the ERO resulted in the event being handled in what seemed to be an almost routine manner.

The licensee intended to issue a Licensee Event Report (LER) with additional details and any remaining corrective actions. The inspectors will conduct further reviews of the event in conjunction with evaluating the LER when issued.

O2 Operational Status of Facilities and Equipment

O2.1 Engineering Safety Feature System Walkdowns

a. Inspection Scope (71707, 92903)

The inspectors used Inspection Procedure 71707 to walk down selected portions of the following ESF systems:

- Emergency Diesel Generators (EDGs)

b. Observations and Findings

The inspectors were concerned that starting air pressures of the unit 1 EDGs were not set according to the Updated Safety Analysis Report (USAR). Section 8.4.2 of the USAR stated, "Each diesel engine is automatically started by compressed air stored at a pressure of approximately 250 psi." Preliminary discussions with the system engineer indicated that the starting air compressors were set to cycle between 219 psi and 245 psi. Thus, the starting air accumulators would never normally be pressurized to 250 psi. However, further review by the system engineer determined that the compressors were actually set to cycle between 219 psig and 245 psig (234 to 260 psi). This confirmed that the plant was being operated according to the USAR. The system engineer initiated actions to clarify the setpoints.

In addition, the inspectors noted that the same section of the USAR stated that each diesel had "two accumulators each of sufficient capacity to crank the engine for 20 seconds." In case of failure of the starting air compressors, the operators would not normally be aware of the situation until starting air low pressure alarms were received. Those alarms were set at 175 psi. The inspectors were concerned that 175 psi might not be sufficient for the engines to meet the 20 second cranking design specification. Discussions with the system engineer indicated that the preoperational and subsequent testing of the engines proved that the air pressure was sufficient for at least 20 seconds of cranking starting from slightly less than 175 psi initial pressure.

c. Conclusions

The inspectors identified no additional concerns with the EDGs. Material condition of the systems appeared excellent. The inspectors noted that all four EDGs were challenged shortly after the walkdown by the loss of offsite power event discussed in Section O1.2. All EDGs performed as designed.

O3 Operations Procedures and Documentation

O3.1 Operations Procedural Deficiencies

a. Inspection Scope (71707)

The inspectors reviewed selected operating procedures for accuracy as a part of a licensed operator examination review and validation.

b. Observations and Findings

On April 5, 1993, procedure C20.1, "Electrical Power System - System Underfrequency Disturbance," was removed from the Operations Manual. That procedure had contained guidance on actions for recovery from degraded voltage and/or frequency conditions. A new procedure C20.3, "Electrical Power System - Security Analysis," was issued on the same day to clarify conflicting information regarding the operation of the substation. The inspectors reviewed C20.3 and associated abnormal procedures with a licensee representative. The inspectors did not find operational guidance that would aid the operators in taking appropriate actions to mitigate a degraded grid voltage event. The licensee did not provide any additional procedural guidelines or management expectations to address operator actions during such an event. During the performance of the dynamic simulator scenarios with a degraded grid voltage event, alarm annunciator C47006-0504,"345 KV SYS UNDERFREQ," was actuated. The alarm response procedure directed the operators to refer to procedure C20.1 for guidance. Without C20.1 guidance, two crews performed different actions for the same initiating event.

During the performance of surveillance procedure SP-1295, "D1 Diesel Generator Fast Start Test," the inspectors identified a procedural inconsistency. Test acceptance criteria in Steps 7.9, 7.11, and 7.12

were identified and those steps provided recording space for the "as found" data. Steps 7.25 and 7.35 also contained acceptance criteria information, but they did not provide recording space for nor required the operator to record the "as found" data. Furthermore, the inspectors identified in review of the "Purpose and General Discussion" section of SP-1295, that the acceptance criteria of Step 7.25 was a Technical Specification requirement for operability determination.

c. Conclusions

The licensee acknowledged the procedural deficiencies. On the first item, the licensee noted that procedure revisions to incorporate the guidance formerly in C20.1 were in the final stages of approval. In addition, the licensee chan[illegible] the annunciator response procedure to delete the reference to C2[illegible]. A licensee representative stated that the revisions had been in progress before the discrepancy had been noted by the inspectors. Therefore, the violation will not be cited because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C) (282/96007-01).

O5 Operator Training and Qualification

O5.1 General Comments

A licensed operator examination was conducted at the licensee's training center and in the plant during the week of May 6, 1996. The examination was administered in accordance with NUREG-1021, Revision 7, "Operator Licensing Examiner Standards" to six reactor operator applicants. The examination was in the form of individual written and operating examinations for licensing determination. Details of this examination are contained in examination report number 282/306/OL-96-01.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62703)

The inspectors observed all or portions of the following maintenance and surveillance activities:

- SP 2136.2 Unit 2 Containment Maintenance Airlock Volumetric Test
- SP 1037 Unit 1 Turbine Overspeed Trip Test
- WO 9604411 Inspect and Clean Cooling Water Emergency Intake Line

- WO 9604137 Receipt Inspect TN-40 #06 Spent Fuel Cask
- WO 9604730 Move Spent Fuel Cask TN-40 #06 to Storage

b. Observations and Findings

No discrepancies or weaknesses were noted in the performance of the above maintenance activities.

c. Conclusions

The inspectors found the work performed under these activities to be professional and thorough. 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 required by procedure. When applicable, appropriate radiation control measures were in place. Surveillance activity acceptance criteria was checked against the appropriate Technical Specification and Updated Safety Analysis Report requirements. Additional comments on certain maintenance activities are discussed below.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 (Open) Licensee Event Report (LER) 282/96-11 (92700): Degraded Steam Generator Tube Sleeves. On May 28, 1996, the licensee discovered that unit 1 was outside the licensing basis due to steam generator tube sleeves indications of weak welds. They found four steam generator tube sleeves in service may have had insufficient weld fusion to make them completely leak tight. The licensee had come to that conclusion after re-evaluating ultrasonic examination data gathered during the last refueling outage. They initiated the re-evaluation due to information learned from destructive examinations of tubes sleeves removed during that outage. After the original report, the licensee determined that one of the four tubes was actually plugged so only three tubes were still in service.

The licensee had been performing extensive evaluations and operability assessments of the problems with sleeve welds. Some of those efforts were documented in Inspection Reports 282/306/96-04, Section 2.8, and 282/306/96-06, Section M8.1. The licensee also documented their efforts in LER 282/96-07 and the letter to the NRC dated June 27, 1996, entitled "January 1996 Steam Generator Sleeving Issues Ninety Day Response Letter." The licensee performed a safety evaluation for the three tubes left in service as discussed in the LER. The LER will remain open pending NRC Office of Nuclear Reactor Regulation review of the evaluation and other steam generator sleeving issues.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Inspection - Review of Non Destructive Examination Data

a. Inspection Scope (73753 and 73755)

The NRC inspectors reviewed data recorded during inservice inspection (ISI) activities performed in the 1996 refueling outage at Monticello to determine compliance with the American Society of Mechanical Engineers (ASME) Code and NRC requirements.

b. Observations and Findings

For ultrasonic test (UT) examinations of dissimilar metal welds, paragraph III-3411(b) of Appendix III of Section XI, 1986 Edition of the ASME Code required the following: "If the examination will be conducted from both sides, calibration reflectors shall be provided in both materials." Contrary to the above, at Monticello, the inspectors identified that a dissimilar metal weld was ultrasonically examined from both sides and a single calibration block had been used for calibration.

As a result, the inspectors requested the licensee to identify all examinations that were performed according to paragraph 3.5 of procedure ISI-UT-16, Revision 11, "UT Examination of Welds of Austenitic and High Nickel Alloy Materials," for Monticello and Prairie Island. Those examinations were considered examples of a deviation from paragraph III-3411(b) of Appendix III of Section XI, 1986 Edition, of the ASME Code requirements for performing UT examinations of dissimilar metal welds. The affected examinations identified for Prairie Island were:

- Report 94-0206, Nozzle to Safe End Examination, Cal block #6.
- Report 96-0146, Safe End to Nozzle Examination, Cal block #54.

c. Conclusions

The Notice of Deviation was issued with the Monticello Inspection Report 263/96-06, Section M3.2 (Deviation 263/96006-02). The discussion included findings for both the Monticello and Prairie Island plants. Since the ISI examinations were conducted by the same licensee employees, and corrective actions would affect both sites, a separate Notice of Deviation was not issued for Prairie Island.

III. Engineering

E1 Conduct of Engineering

E1.1 Modification Failed to Ensure Design Adequacy Resulting in Inoperable Auxiliary Feedwater (AFW) Pumps.

a. Inspection Scope (37551)

On May 20, 1996, with both units operating at 100 percent power, Prairie Island declared all four AFW pumps (two per unit) inoperable because they were not protected against run-out for all accident conditions. The licensee informed the NRC per 10 CFR 50.72 requirements, and subsequently completed actions in time to allow the pumps to be declared operable before any actual power reduction. The inspectors reviewed the principal root causes for the inoperable pumps as well as short term corrective actions and the long term corrective action plans. This included reviews of the License Event Report (LER) 96-0010, and GL 91-18 evaluations as well as 50.59 safety evaluations relating to this issue.

b. Observations and Findings

Brief History of AFW Pump Run-out Protection at PINGP

Pressure switches were installed to protect the AFW pumps against run-out via Modification 80L579. The modification was a commitment added in response to Bulletin 80-04 "Analysis of a PWR Main Steam Line Break With Continued Feedwater Addition" and NUREG 578, "TMI-2 Lessons Learned Task Force Status Report and Short-Terms Recommendations." The modifications were to prevent the pumps from being damaged by cavitation while in run-out conditions due to a secondary system break. In January 7, 1982 correspondence to the NRC, NSP stated that the discharge pressure switches would be set below the minimum differential head at maximum flow (887 psig at 320 gpm).[1] NSP further stated that the setpoints would have 100-150 psi margin below the total differential head (TDH) to prevent spurious trips with actual setpoints to be selected following installation and testing. (Although setting the switches below the minimum TDH does not appear conservative, pre-operational test data and vendor information supported operation without cavitation for a certain range below the minimum TDH).

These pressure switch installations were completed on December 12, 1982, and contrary to the setting values discussed in the correspondence, the discharge pressure switch setpoints were set at 500 psig for the motor-driven AFW pumps and 200 psig for turbine-driven AFW pumps. PINGP could not provide adequate justification or bases for these setpoints.

[1] The pump's design head is 1250 psig at 220 gpm.

Identification of Lack of Protection for AFW Pumps

In May of 1996, PINGP's self-assessment of implementation of the 10 CFR 50.59 safety evaluation program questioned the appropriateness of the AFW pump low discharge pressure trip setpoints. The primary concern was that the as-left switch setpoints would not protect the pumps against pump run-out for intermediate sized secondary side pipe breaks. Based on pre-operational testing data the licensee surmised that the onset of cavitation was in a range below 750-800 psig.

Per Prairie Island's Accident Analysis, a faulted SG would be isolated within 10 minutes and the AFW pumps would be required for delivery of AFW flow to the unfaulted loop. For large secondary side cracks or breaks, a faulted steam generator would quickly depressurize, placing excessive demand on the AFW pump resulting in a pump trip on low discharge pressure. For very small crack sizes the secondary side pressure could, theoretically, provide sufficient backpressure to the pumps to prevent run-out until operator action could be taken to isolate the faulted SG. Thus, the concern relates to a range of postulated secondary side break/crack sizes where the pump discharge pressure would hover above the trip setpoint but below the onset of cavitation, and (without operator intervention) pump damage could occur. For these scenarios, the absence of protection would result in the failure of the AFW pumps to provide the necessary flow to remove decay heat during accident mitigation. Since the potential for damage to both AFW pumps in either unit could be postulated, all four pumps were declared inoperable on May 20, 1996, and Technical Specification 3.0 was entered.

CORRECTIVE ACTION

For short term corrective action, the licensee implemented special order to prevent run-out (cavitation) by requiring that AFW pump discharge pressure be maintained greater than 900 psig by throttling the discharge motor operated valves. Throttling of the discharge valves will not affect design heat removal capabilities. Guidance in the operations procedure ensures that minimum flow requirements are satisfied for heat removal. As discussed in NRC inspection report (IR) 50-282/306/96-006, this order was supported by a temporary change to operations instructions to add the responsibility of maintaining AFW pump discharge pressure to one of the minimum complement of licensed operators required to be in the control room. A 50.59 safety evaluation satisfactorily evaluated the manual operator actions against the criteria contained in NRC Generic Letter 91-18. The inspectors had noted that the Operations Committee review of this issue was thorough and training was conducted on the manual operator actions for all operating crews. Interviews with selected licensed operators indicated that they understood their responsibilities detailed in the special order. The pumps were returned to operable, but degraded, status after implementation of the manual actions.

For long term corrective action, PINGP had initiated development of an AFW system hydraulic model with the objective of removing reliance on operator action to preclude potential pump damage. The information from the hydraulic model will support a modification that had been initiated to install flow restriction orifices so that the pumps will not be operated in run-out regions of the pump curve. The inspectors noted that these actions had been given high priority with scheduled implementation to begin during the next refueling outage scheduled for January 1997. Further, other ongoing efforts by PINGP are targeted at identifying any similar issues. These efforts included USAR reviews, system design reviews and reconstruction efforts, resolution of DBD follow-on items, and verification that other earlier plant activities that had not been reviewed under 50.59 safety evaluations were re-reviewed. NRC's review of NSP's long term corrective actions and resolution of this issue will continue to be tracked under the unresolved item opened in IR 96001 (50-282/306/96006-01). The inspectors concluded that the corrective actions taken had been comprehensive and these actions were pursued aggressively by the licensee without NRC intervention.

ROOT CAUSE

The inspectors concluded that the principal root cause for the inadequate pump trip setpoint and thus, the lack of protection for all postulated breaks was a lack of design control during implementation of Modification 80L579. The basis for the chosen pump trip setpoints was never clearly elucidated. Available information indicated that the designers assumed that if run-out conditions occurred, the pump discharge pressure would drop off immediately allowing the pressure switches to trip the pump (when, in fact, the pump may operate in the run-out regime in a stable but cavitating mode where the pump internals would be damaged). The inspectors did not identify other design control problems during the early 1980s to indicate that this was a programmatic problem with PINGP design modifications.

The original design of PINGP's AFW system did not include run-out protection for the pumps. The plant's architect engineer had no basis for dismissal of this protection. Therefore, NSP's 1982 implementation of design modification 80L579 provided an opportunity to fully address this concern. However, the design modification did not consider all potential sizes of secondary side pipe ruptures during development and implementation. PINGP's design controls did not assure that the design basis (i.e. for all potential sizes of secondary system pipe ruptures, provisions must be made in the design of the AFW system to ensure the minimum flow to the remaining unfaulted loops, USAR 11.9.3.b) was appropriately translated when specifying the pressure switch trip setpoint. Further, the modification's design reviews did not identify and correct the design error or fully verify the design adequacy until re-reviewed by PINGP in May 1996.

c. Conclusions

PINGP's design controls during development and implementation of modification 80L579, installed in December 1982, appeared not to assure that the plant's design basis was appropriately translated when specifying the AFW pump low pressure switch trip setpoint. Further, the modification's design reviews appeared not to identify or correct the design error or fully verify the design adequacy until re-reviewed by PINGP in May 1996. PINGP's corrective actions upon identification of this issue were thorough and aggressive. This is an apparent violation (282/96007-02). No Notice of Violation is currently being issued pending further NRC management consideration of this violation.

E2 Engineering Support of Facilities and Equipment

E2.1 Inspection and Cleaning of Cooling Water Emergency Intake Line

a. Inspection Scope (62703, 92903)

As discussed in Inspection Report 282/306/95-14, Section 3.13, the licensee determined that the cooling water emergency intake line did not pass sufficient flow to meet its original design basis. One of the problems was thought to be possible silting in the line. During this inspection period the licensee contracted for inspection and cleaning of the emergency intake pipe.

b. Observations and Findings

The licensee determined that the intake pipe contained from one to five inches of silt on the bottom. No large items of debris, asiatic clams, or zebra mussels were found. A layer of algae covered most of the pipe.

During preparations for cleaning the pipe, the licensee determined by observation of the results that surveillance procedure SP 1528, "Backflush of Emergency Bay Intake Pipe," Revision 18, may not have been completely effective in removing the silt when performed for the specified 30 minutes. However, when performed for 60 minutes, the surveillance removed most of the debris and silt. The licensee was in the process of changing the surveillance to specify a 60 minute backflush.

SP 1528 was not a surveillance required by Technical Specifications. The surveillance was conducted monthly per a licensee commitment in a letter to the NRC dated January 29, 1990. The commitment was in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

The licensee intended to complete a safety evaluation and perform a flow verification test later in 1996, when river temperature and cooling water demand conditions allowed. This was to determine the overall effectiveness of the cleaning and backflushing, and to determine whether even a clean line could meet the original design basis.

c. Conclusions

The results of the inspection of the intake line indicated that there may have been some flow degradation due to silting. However, the licensee had not determined whether even a clean line could meet the original design basis. The acceptability of the licensee's temporary corrective actions remains an Unresolved Item (282/95014-02) pending completion of a review by the NRC Office of Nuclear Reactor Regulation.

E2.2 (Open) License Event Report (LER) 306/96-01: Reactor Trip Caused by Failure of Feedwater Regulating Valve.

a. Inspection Scope (37550)

The inspectors examined LER 96-01, Nonconformance Report (NCR) 2010410, and proposed corrective actions, including the proposed modifications to the valve internals. The inspectors also discussed corrective actions taken and planned with systems engineering personnel.

b. Observations and Findings

As discussed in inspection report 282/306/96-06, a unit 2 reactor trip occurred because of failure of the feedwater regulating valve CV-31135. During disassembly of CV-31135 it was observed that the valve plug had separated from the stem.

The licensee had determined that one of the primary causes of the valve failure was the torsional force on the valve plug which had not been accounted for in the design of the stem/plug interface. That root cause was supportable because the through-pin used in the stem/plug connection had sheared under obvious torsional loads, plus the licensee observed torsional loads on the visible portion of the stem during low power/low flow operation. For the short term, the licensee replaced the valve internals with like components and restarted the plant pending a design modification on the stem/plug connection. The design of the stem/plug modification was in progress and was a collaborative effort between the valve vendor and plant engineering.

The proposed changes to the connection (extension of the stem so that it passes through the plug assembly and allows torquing of the nut and welding of the nut to the stem) qualitatively appeared adequate and reasonable and would distinctly increase the joint resistance to any applied torsional moment. However, the design changes had not been qualified quantitatively via analysis. The licensee intended to complete the qualifications after obtaining strain measurements from the valve stems to quantify the magnitude of the applied force and the flow conditions where the highest loads are exhibited. Those corrective actions will be reviewed in a future inspection.

As discussed in the LER, any pre-existing material flaws, such as the stem crack noted in the failed stem, would expedite the stem/plug separation after the assembly was weakened via the torsional loads. For

that reason, and in view of the interim like-for-like solution, the inspectors asked why the replacement stem had not been non-destructively examined with a relatively expeditious exam such as dye-penetrant testing prior to installation. In response, the licensee maintained that the stem cracks had been re-evaluated and were considered ancillary causes to the valve failure, therefore minimal value would be added by nondestructive testing.

c. Conclusions

Overall, actions taken to address the failed feedwater regulating valve have been comprehensive and methodical. The depth of the system engineer's knowledge of individual component history, qualifications and design parameters was very good. The inspectors noted that the planned design modification to the stem/plug assembly was not quantitatively qualified and was awaiting testing of stem torsional loads during a future power ascension to fully validate the design. The decision to install the replacement stem without verification of material flaws via nondestructive testing marred an otherwise conservative approach in corrective action for the valve failure.

E2.3 Review of USAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Safety Analysis Report (USAR) description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the USAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected. The following inconsistency was noted between the wording of the USAR and the plant practices, procedures, and parameters observed by the inspectors:

As discussed in Section E8.1 of this report, USAR Section 5.4.2.2.3 incorrectly stated that the hydrogen monitor system data acquisition and control assemblies were located in the control room. Those components were located in the environmental monitoring equipment rooms. The associated strip chart recorders were located in the control room. The discrepancy was considered an editorial error and turned over to the licensee for resolution. This is an open inspection item pending review of the licensee's resolution (282/96007-03).

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 282/96006-04 and (Closed) Licensee Event Report 282/96-09: Exceeding Technical Specifications Limiting Conditions for Inoperability of Post Accident Containment Hydrogen Monitors due to Pressure Regulator Drift of the Calibration Manifold.

a. Inspection Scope (92700, 92903)

This issue was previously discussed in Inspection Report 282/306/96-06, Section M2.2. During this inspection period the inspectors continued their review of the circumstances surrounding the event.

b. Observations and Findings

LER 282/96-09 described the events leading up to the licensee's finding that three of four containment hydrogen monitors were inoperable for a period of time longer than allowed by Technical Specifications. The inspectors review disclosed the following additional information and clarifications:

- On February 14, 1996, Work Order (WO) 9600752 to perform leak checks of the hydrogen sensor platforms was conducted. During that job the following activities were performed on verbal instructions of the system engineer, there were no instructions to perform them written in the work package:

  * All eight regulator settings were set to 12 psig nominal (12 - 14 psig actual). That was documented only in a note attached to the WO.

  * The capability of each sensor's calibration equipment to function at the 12 psig regulator setting was tested. That was not documented in the WO.

  * A calibration gas usage rate test was performed on one sensor and the results improved after the regulator setting was changed. That result was documented only in a note attached to the WO.

- There was no instruction in WO 9600753 to perform post-maintenance testing. However, the quarterly calibration surveillance was successfully performed on February 16.

- On February 20, per WO 9600753, all eight calibration gas bottles were filled. The work package specified that it be performed in accordance with procedure D87, Revision 1, "Containment Hydrogen Monitor Calibration Gas Fill." Procedure D87 instructed the technicians to fill the gas bottles to 1800 psig. Instead, the technicians filled the gas bottles to 2250 - 2400 psig. WO 9600753 was then closed out.

- As discussed in the LER, one of the four sensors did calibrate properly on May 14, 1996. However, the control room display for containment hydrogen was the auctioneered high sensor from each train. Since three inoperable sensors were reading falsely high after the calibration, operator actions would have been required to recognize the condition and eliminate the faulted sensor from

the auctioneering circuitry to provide the valid sensor's output to the control room. Therefore, that train was considered inoperable even with one operable sensor.

- The licensee performed an inadequate evaluation of the regulator setting change. Changing of pressure regulator settings was apparently not covered by the licensees design control or configuration management procedures. The LER corrective actions did not address that issue.

- The Updated Safety Analysis Report (USAR), Section 5.4.2.2.3, incorrectly stated that the hydrogen monitor system data acquisition and control assemblies were located in the control room. Those components were located in the environmental monitoring equipment rooms. The associated strip chart recorders were located in the control room. The same error was also present in procedure H8-D.5.2, "EXO Sensors (Whittaker) - Containment Hydrogen Sensor."

c. <u>Conclusions</u>

The containment hydrogen monitoring system was providing valid containment hydrogen concentration data until the system was calibrated on May 14, 1996. If an accident were to have occurred, the sensors would have provided valid indications until calibration 24 hours later. Upon calibration, a significant change in concentration would have been indicated (> 6 percent). A hydrogen environment of this magnitude would not be expected for several days.

Updated Safety Analysis Report (USAR), Figure 5.4-2, indicated that if uncontrolled, hydrogen concentration would not exceed 4 percent for approximately 16 days. Alternate methods of hydrogen monitoring for consistency checking were available, including the automatic gas analyzer system (non-safeguards power) and containment atmosphere grab sample analysis (USAR Section 5.4.2.2.3). Thus, as stated in the LER, the event posed little threat to health and safety of the public.

However, the condition would have caused unnecessary confusion during a design basis event and would have complicated analysis and recovery actions. Thus the condition was cited even though licensee-identified.

Technical Specification 3.15.A required that 2 channels of containment hydrogen monitors shall be operable in Modes 1 and 2.

Technical Specification 3.15.B required that with two hydrogen monitor channels inoperable, the Licensee must restore one channel to operable status within 72 hours or be in at least Mode 3 within the next 6 hours.

Contrary to the above, from March 3 through May 15, 1996, while in Modes 1 or 2, both Unit 1 hydrogen monitor channels (train A sensors 1XE-719 and 1XE-720; train B sensor 1XE-722) were inoperable because calibration

equipment was degraded and action was not taken to restore at least one channel to operable status within 72 hours or to be in at least Mode 3 within the next 6 hours. This was a violation. (282/96007-04)

The LER associated with the event was considered closed and remaining corrective actions in the LER will be followed when the violation corrective actions are reviewed.

E8.2 <u>(Closed) Violation 282/306/95014-03 (40500, 92903)</u>: Safety Evaluation Not Performed Prior to Special Test. This issue was discussed in Inspection Report 282/306/95-14, Section 3.14. The violation concerned the failure to perform a safety evaluation in accordance with 10 CFR 50.59 prior to performing a special test of the emergency intake line.

In response to this violation, the licensee conducted a detailed self-assessment of the safety evaluation process. The self-assessment evaluated whether safety evaluations were appropriately initiated, whether they contained enough detail, and whether the right conclusions were reached. Additionally, the licensee had reviewed previous changes, tests, and experiments where a safety evaluation was not performed to ensure that the screening criteria of 10 CFR 50.59 or 72.48 were appropriately applied.

The licensee also revised the procedure for performing safety evaluations to include a screening form to be used when safety evaluations were determined not to be necessary. The NRC inspectors reviewed the self-assessment and the findings and concluded that the self-assessment was aggressive and thorough. The screening form appeared to provide reasonable questions to ensure that safety evaluations would be performed when required. The inspectors concluded that the licensee's corrective actions were sufficient to prevent recurrence of the violation.

<u>IV. Plant Support</u>

R1 Radiological Protection and Chemistry Controls

R1.1 <u>Small Chemical Discharge to the River (93702)</u>

On July 7, 1996, the licensee reported to the NRC in accordance with 10 CFR 50.52 that they had made a small release of diluted sodium hydroxide to the Mississippi River and reported it to the State of Minnesota and the National Response Center. The release was reported to be of less than a reportable quantity and not a violation of the state discharge permit. The inspectors had no further concerns with this issue.

R3 Radiological Protection and Chemistry Procedures and Documentation

R3.1 Technical Specifications Required Reports Submitted Late

a. Inspection Scope (92904)

In June 1996, while conducting a review of occupational exposure data for various reactors, the NRC Office of Nuclear Regulatory Research noted that the licensee did not submit routine annual reports of occupational exposure, safety and relief valve failures and challenges, and primary coolant iodine spikes required by March 1 of each year in accordance with Technical Specification 6.7.A.1. The NRC Project Manager contacted the licensee and asked about the report.

b. Observations and Findings

The licensee discovered that they had drafted the report in a timely manner but, through an administrative oversight, had apparently failed to route the letter for signature and mail it. The licensee then submitted the required report on June 20, 1996. As part of the corrective action for this error, the licensee obtained an index of all correspondence received by the NRC Document Control Desk for the Prairie Island dockets in the last year to compare to their data base of required reports and their files of submitted reports. No additional missing reports had been identified at the end of the inspection period. Additional actions were taken by the licensee to address the personal performance issues.

c. Conclusions

Failure to submit the required report was a violation of Technical Specifications but was the result of an administrative oversight and had no safety significance. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. (282/96007-05)

P1 Conduct of EP Activities

P1.1 Notification of Unusual Event (NUE)

a. Inspection Scope (71750, 93702)

On July 29, 1996, at 3:05 PM, the licensee declared an NUE as a result of a dual unit trip and partial loss of offsite power discussed in Section O1.2 of this report. The inspectors responded to the site and monitored the activities in the technical support center (TSC) and control room.

b. Observations and Findings

The licensee properly evaluated the event and made the proper emergency classification. After making the required initial notifications to

offsite officials, the shift manager initiated a callout to the emergency response organization (ERO) to provide managerial, technical, and maintenance support for the recovery.

The TSC provided excellent support to the operators during the event. TSC staff prioritized work, provided technical assessments of the remaining offsite power capabilities, coordinated offsite power restoration efforts with the system load dispatcher, and performed numerous other functions. Status boards were maintained up to date. Frequent status briefings were held. Schedules were established to facilitate manning for long-term support. Lessons learned from exercises and drills were used and all activities were performed smoothly.

The TSC would not normally be manned at the NUE level. Because of the complexity of the initiating event and recovery actions, the decision was made to man the center and direct activities from there was prudent. The emergency operations facility (EOF) was also manned. The inspectors did not observe activities in the EOF. EOF staff also provided support for the event recovery. The operational support center was not manned. Instead, extra support personnel were directed to report to their normal work stations until needed.

The NUE was terminated at 10:35 AM on June 30, 1996, when both units met the Technical Specifications requirements for offsite power sources and all emergency diesel generators were secured and returned to normal standby condition.

c. Conclusions

The licensee properly classified and reported the event, conservatively activated the ERO, and used the ERO to provide excellent support to the operators in recovery from the event. Lessons learned from exercises and drills were effectively used in this response to an actual event.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on July 11, 1996. 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. Wadley, Plant Manager
M. Agen, Senior Consultant, Emergency Planning
K. Albrecht, General Superintendent, Engineering
J. Goldsmith, General Superintendent, Design Engineering
J. Hill, Manager, Quality Services
G. Lenertz, General Superintendent, Plant Maintenance
D. Schuelke, General Superintendent, Radiation Protection and Chemistry
M. Sleigh, Superintendent, Security
J. Sorensen, General Superintendent, Plant Operations

INSPECTION PROCEDURES (IPs) USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events At Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

282/96007-01	NCV	Failure to provide adequate operating procedures for degraded voltage or under frequency condition.
282/96007-02	URI	Removal of feedwater pump cavitation protection
282/96007-03	IFI	Resolution of incorrectly stated hydrogen monitor system data acquisition in USAR Section 5.4.2.2.3.
282/96007-04	VIO	Failure to Meet Technical Specification Limiting Conditions for Operation of the Containment Hydrogen Monitoring System
282/96007-05	NCV	Failure to Submit Annual Report Required by Technical Specifications On Time

Closed

282/95014-03	VIO	Safety Evaluation Not Performed for Special Test
306/95014-03	VIO	Safety Evaluation Not Performed for Special Test
282/96006-04	URI	Exceeding Technical Specifications Limiting Conditions for Inoperability of Post Accident Containment Hydrogen Monitors due to Pressure Regulator Drift of the Calibration Manifold
282/96007-02	NCV	Failure to Submit Annual Report Required by Technical Specifications On Time

282/96-09	LER	Exceeding Technical Specifications Limiting Conditions for Inoperability of Post Accident Containment Hydrogen Monitors due to Pressure Regulator Drift of the Calibration Manifold

Discussed

282/95014-02	URI	Acceptability of Manual Operator Actions During a Design Basis Accident
263/96006-02	DEV	Failure to Follow ASME Code for Ultrasonic Tests of Dissimilar Metal Welds (Monticello Report Item)
306/96-01	LER	Reactor Trip Caused by Failure of Feedwater Regulating Valve
282/96-11	LER	Degraded Steam Generator Tube Sleeves

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
DBD	Design Basis Document
DEV	Deviation
EDG	Emergency Diesel Generator
EOF	Emergency Operations Facility
ERO	Emergency Response Organization
GL	Generic Letter
IP	Inspection Procedure
ISFSI	Independent Spent Fuel Storage Installation
ISI	Inservice Inspection
KV	Kilo (Thousand) Volts
LER	Licensee Event Report
MW	Mega (Million) Watts
NCR	Nonconformance Report
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
NUE	Notification of Unusual Event
PDR	Public Document Room
PSI	Pounds Per Square Inch
PSIG	Pounds Per Square Inch Gauge
PWR	Pressurized Water Reactor
SG	Steam Generator
SP	Surveillance Procedure
TDH	Total Differential Head
TN	Transnuclear Corporation
TSC	Technical Support Center
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic Testing
VIO	Violation
WO	Work Order