UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

November 7, 2008

EA-08-272

Mr. Michael D. Wadley
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company-Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT – NRC SPECIAL INSPECTION REPORT 05000282/2008008; 05000306/2008008, PRELIMINARY WHITE FINDING

Dear Mr. Wadley:

On October 6, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The Special Inspection Team evaluated the facts and circumstances surrounding the Unit 1 reactor trip and the failure of 11 turbine-driven auxiliary feedwater pump (TDAFWP) to run, which occurred on July 31, 2008. Additionally, the team evaluated the facts and circumstances associated with the declaration of a Notice of Unusual Event (NOUE) on August 3, 2008, due to indications of excessive levels of hydrazine in the condenser pit area of Unit 1. The enclosed Inspection Report documents the results of the inspection, which were discussed on October 6, 2008, with you and other members of your staff.

Based on the deterministic criteria provided in Management Directive (MD) 8.3, “NRC Incident Investigation Program,” the incident met MD 8.3 Criterion h, “Involved questions or concerns pertaining to licensee operational performance.” The special inspection evaluated the causes of the reactor trip; the failure of the TDAFWP to run when demanded; and the NOUE; as well as the actions taken by your staff in response to the reactor trip and recovery.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The enclosed inspection report discusses a finding for Unit 1 that appears to have low to moderate safety significance (White). As documented in Section 4OA3.3 of this report, due to a configuration control issue, which isolated the discharge pressure switch associated with 11 TDAFWP, the pump was rendered inoperable for a time period that significantly exceeded the 72 hour time limit allowed by Technical Specifications.

This finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process (SDP). The preliminary safety significance of the finding was determined assuming 11 TDAFWP was inoperable for 138 days, during an operational Mode that required two operable trains of auxiliary feedwater.

This finding was not an immediate safety concern because the 11 TDAFWP was not required to mitigate the trip and, upon identification of the issue, your staff took prompt corrective actions to restore the mispositioned valve to its normal (open) position; performed valve lineups to verify correct equipment configurations for the remaining auxiliary feedwater pumps; and performed appropriate surveillance testing on the 11 TDAFWP to verify the component's operable status.

The finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's web site at http://www.nrc.gov/reading-rm/adams.html.

In accordance with Inspection Manual Chapter (IMC) 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of this letter. The SDP encourages an open dialog between the staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination.

Before the NRC makes its enforcement decision, we are providing you an opportunity to either: 1) present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a conference is held, it will be open for public observation. The NRC will also issue a press release to announce the conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter. If you decline to request a Regulatory Conference or to submit a written response, you relinquish your right to appeal the final SDP determination; in that, by not doing either you fail to meet the appeal requirements stated in the Prerequisite and Limitation Sections of Attachment 2 of IMC 0609.

Please contact Richard Skokowski at 630-829-9620 within 10 days of the date of this letter to notify the NRC of your intended response. If we have not heard from you within ten days, we will continue with our significance determination and enforcement decision. You will be advised by a separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. Please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA by Gary L. Shear, Acting for/

Cynthia D. Pederson, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2008008; 05000306/2008008
w/Attachments:

1. Supplemental Information
2. Timeline of Events Unit 1
3. Special Inspection Charter

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See next page

Letter to M. Wadley from C. Pederson dated November 7, 2008

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT – NRC SPECIAL INSPECTION REPORT 05000282/2008008; 05000306/2008008, PRELIMINARY WHITE FINDING

cc w/encl:
D. Koehl, Chief Nuclear Officer
Regulatory Affairs Manager
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J. Stine, State Liaison Officer, Minnesota Department of Health
Tribal Council, Prairie Island Indian Community
Administrator, Goodhue County Courthouse
Commissioner, Minnesota Department of Commerce
Manager, Environmental Protection Division
  Office of the Attorney General of Minnesota
Emergency Preparedness Coordinator, Dakota
  County Law Enforcement Center

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Letter to M. Wadley from C. Pederson dated November 7, 2008

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NRC SPECIAL INSPECTION REPORT 05000282/2008008; 05000306/2008008,
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos. License Nos.	50-282; 50-306 DPR-42; DPR-60
Report No:	05000282/2008008 and 05000306/2008008
Licensee:	Northern States Power - Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, Minnesota
Dates:	August 4 through October 6, 2008
Inspectors:	S Thomas, SRI, Monticello (Lead) K. Stoedter, SRI, Prairie Island D. Betancourt, Reactor Engineer
Approved by:	R. Skokowski, Chief DRP Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000282/2008008; 05000306/2008008; August 4, 2008, to October 6, 2008, Prairie Island Nuclear Plant, Units 1 and 2; Other Activities; SIT regarding the failure of 11 TDAFWP to run following the reactor trip on July 31, 2008, and declaration of a NOUE on August 3, 2008.

This report covers a 64-day period of special inspection by one NRC Region III inspector and two resident inspectors. One apparent violation, with potential safety significance greater than Green, was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- AV: A self-revealing apparent violation of Technical Specifications was associated with the licensee's failure to adequately control the position of a valve that could isolate the 11 TDAFWP's discharge pressure switch. Because of the valve being closed, the 11 TDAFWP failed to run as required, subsequent to a reactor trip. The manifold isolation valve was determined to have been shut for 138 days, rendering the 11 TDAFWP inoperable for a time period that significantly exceeded the Technical Specification allowed outage time (72 hours) for the pump. This issue has been preliminarily determined to be of low to moderate safety significance (White) for Unit 1. This issue was entered into the licensee's corrective action program (CAP 01146005). The licensee took prompt corrective actions to restore the mispositioned valve to its normal (open) position; perform valve lineups to verify correct equipment configurations for the remaining auxiliary feedwater pumps; and perform appropriate surveillance testing on the 11 TDAFWP to verify the component's operable status.

  This finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," because it impacted the configuration control attribute of the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of the systems that respond to initiating events to prevent undesirable consequences. The cause of this finding was related to the cross-cutting element of human performance for resources (H.2.(c)). (Section 4OA3.3)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Event

On July 31, 2008, at 8:17 a.m., Prairie Island Unit 1 tripped due to a spurious overtemperature delta temperature (OTΔT) signal on the reactor protection system red channel concurrent with planned testing on the reactor protection system yellow channel. After the reactor tripped, the 11 turbine-driven auxiliary feedwater pump (TDAFWP) started as required, then stopped approximately 40 seconds later due to a low discharge pressure trip. The licensee determined that the cause of the TDAFWP trip was an incorrect valve lineup associated with the auxiliary feedwater pump's discharge pressure instrumentation. Prior to restarting the Unit, the licensee replaced the faulty reactor protection system card that caused the spurious OTΔT signal, corrected the valve lineup issue associated with the 11 TDAFWP discharge pressure instrumentation, and successfully tested both systems.

On August 2, 2008, at 3:42 p.m., the licensee began to startup Unit 1 in accordance with station procedures. Early in the morning on August 3, 2008, while holding at approximately 30 percent power to allow secondary chemistry to stabilize, a technician reported an abnormal odor adjacent to the Unit 1 condenser pit. Air samples taken in the vicinity of the Unit 1 condenser pit indicated positive for hydrazine. The licensee took positive actions to control personnel access to the affected area and, at 3:52 a.m., declared a Notification of Unusual Event (NOUE) for the release of toxic gases deemed detrimental to the normal operation of the plant, in accordance with their Emergency Plan. The licensee utilized extra ventilation in the affected areas to reduce the hydrazine concentration. The licensee continued to take air samples over the next several hours and, based on acceptable sample results, exited the Unusual Event at 10:20 p.m. on August 3, 2008.

Based on the probabilistic risk and deterministic criteria specified in Management Directive (MD) 8.3, "NRC Incident Investigation Program," and Inspection Procedure (IP) 71153, "Event Followup," and due to the equipment performance problems that occurred, a Special Inspection was initiated in accordance with IP 93812, "Special Inspection."

The inspection focus areas included the following charter items:

- Identify the time-line for the event. Include plant conditions, system line ups, and operator actions.

- Review the licensee's post-trip review to determine the cause of the reactor trip. Independently review plant data and records to confirm the adequacy of the licensee's assessment, and corrective actions.

- Review the circumstances surrounding the failure of the TDAFWP, including the most likely cause of the pump failure; the length of time the pump may have been in an unrecognized failed condition; and any potential for operators to recover the failed pump.

- Determine if the licensee is performing a root cause for the reactor trip. As available, evaluate the scope, schedule, staffing and results of the licensee's root cause investigation.

- Determine if the licensee is performing a root cause evaluation for the TDAFWP failure. As available, evaluate the scope, schedule, staffing and results of the licensee's root cause investigation.

- Review procedures for the TDAFWP, including operational line-up procedures and testing procedures, to assess any procedural or testing inadequacies that may have contributed to the failure of the pump.

- Determine if the licensee performed an extent-of-condition evaluation to assess if the contributing causes to the failure of the TDAFWP have the potential to affect other safety-related equipment.

- Review for adequacy the licensee's immediate corrective actions and planned long-term corrective actions to prevent recurrence of both the reactor trip and the failure of the TDAFWP.

Additionally, the Special Inspection team (SIT) was tasked with reviewing the circumstances surrounding the August 3, 2008, declaration of the NOUE associated with release of toxic gases (hydrazine) deemed detrimental to normal operation of the plant.

4. OTHER ACTIVITIES (OA)

4OA3 Special Inspection (93812)

.1 Establish the Sequence of Events Related to the Event, Including Plant Conditions, System Lineups and Operator Actions

a. Inspection Scope

The inspectors reviewed operator logs, plant parameter recordings and computer trending information, and conducted interviews with licensee personnel in developing the sequence of events. In addition, the inspectors' sequence of events was reviewed against the licensee-generated sequence of events to ensure completeness and accuracy.

b. Findings and Observations

No findings of significance were identified. The inspectors' generated sequence of events is included with this report as Attachment 1 and an event narrative summary was presented in this report's "Summary of Plant Event," discussed above.

.2 Reactor Trip Report

a. Inspection Scope

The inspectors reviewed the licensee's post-trip report to determine if the licensee adequately evaluated and corrected the cause of the reactor trip. Specific information reviewed by the inspectors included: reactor trip report; operators logs; emergency response computer system alarm post-trip data; troubleshooting log for the failed OTΔT reactor protection channel; troubleshooting log for the 11 TDAFWP trip; the reactor trip and trip recovery procedures; and recorder traces for various reactor plant parameters.

b. Findings and Observations

No findings of significance were identified.

.3 Trip of the 11 Turbine-Driven Auxiliary Feedwater Pump

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the failure of the 11 TDAFWP to run subsequent to the reactor trip, after receiving a valid start signal. The specific focus of this inspection was to determine the most likely cause of the pump failure; the length of time prior to the trip that the pump was inoperable; and the probability of success for the recovery of the failed pump.

b. Findings and Observations

Introduction

A self-revealing apparent violation of Technical Specifications (TS) 3.7.5.B was identified due to the licensee's failure to control the position of the 11 TDAFWP discharge pressure switch manifold block valve. The failure to control the position of this valve resulted in the 11 TDAFWP being inoperable for 138 days.

Description

A timeline of the relevant information subsequent to the July 31, 2008, Unit 1 reactor trip is as follows:

- 8:17 a.m.; the Unit 1 reactor tripped from full power. Shortly thereafter, both of the Unit's auxiliary feedwater pumps received valid start signals due to expected low post-trip water levels in the steam generators;
- 8:21 a.m.; the "11 TDAFWP Low Suction/Discharge Pressure Trip" annunciator was received in the control room;
- 8:55 a.m.; the remaining auxiliary feedwater pump was secured and normal steam generator levels were maintained using the main feedwater system;
- 9:15 a.m.; the licensee determined that the 11 TDAFWP had started upon receipt of the valid start signal, but tripped approximately 42 seconds later;
- 1:23 p.m.; the licensee discovered an unlabeled manifold block valve associated with the 11 TDAFWP's discharge pressure switch to be shut.

The inspectors reviewed licensee testing procedures and work orders that would have manipulated the manifold block valve. In addition to the work documents that directly manipulated the block valve, the inspectors also reviewed several other procedures, which manipulated similar manifold valves that are located in close proximity to the mispositioned block valve. The inspectors determined that the last documented activity that repositioned the block valve was the performance of SP1234, "11 Aux Feedwater

Pump Suction and Discharge Pressure Switches Calibration," completed on February 23, 2008.

Analysis

The inspectors evaluated the finding using IMC 0609, Appendix A, Attachment 1, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Since the performance deficiency affected the ability of the 11 TDAFWP to start and run upon the receipt of a valid actuation signal, the inspectors used the Phase 1 SDP worksheet for the Mitigating System Cornerstone to determine the significance of the finding. The finding was determined to require a Phase 2 SDP review because the finding resulted in the loss of function of a single train for greater than its TS allowed 72 hour outage time limit.

It is not known when the manifold isolation valve was closed, rendering the pump unavailable for automatic actuation. Based on the inspection results, the valve was last manipulated on February 23, 2008, as part of the Unit 1 refueling outage activities. Therefore, it was assumed that the pump was unavailable since Unit 1 entered Mode 3 on March 15, 2008, until the problem was discovered on July 31, 2008.

Recovery of the 11 TDAFWP was determined to be feasible. The pump would start and run if the control selector switch in the control room was taken to "Manual." The licensee's alarm response Procedure C47010, "11 TDAFWP Lo Suct or Disch Press Trip," instructed operators to restart the pump using Abnormal Operating Procedure 1C28.1AOP4, "Restarting Unit 1 AFWP After Low Suction/Discharge Pressure Trip". This procedure directed operators to put the selector switch in "Manual." The inspectors estimated that the time required to perform the actions in the procedure was approximately 15 minutes. Since the time to core damage, assuming a loss of all feedwater was much longer than 15 minutes; adequate time for recovery of the pump was available.

The Phase 2 pre-solved worksheets modeled Unit 2 components only. The significance of the Unit 2 TDAFWP pump being unavailable for greater than 30 days was Red. This result was overly conservative because it did not include credit for recovering the pump. The result was also conservative because the Phase 2 pre-solved worksheets assumed the exposure period was one year and the actual exposure period was 138 days. Therefore, a Phase 3 SDP analysis was completed.

The SPAR-H model for Prairie Island Unit 1, Revision 3.45 was used for the internal events Phase 3 SDP analysis. For the internal events analysis the basic event AFW-TDP-FS-TDP11, the 11 TDAFWP Fails to Start, was set to "True" and the basic event AFW-XHE-XL-TDPFS, Operator Fails to Recover AFW Pump Fail to Start, was set to a failure probability of 2.2E-2 based on a SPAR-H analysis for operators failing to recover the pump. The SPAR-H analysis assumed that all performance-shaping factors for both diagnosis and action were nominal with the exception of the Stress performance shaping factors. The scenario of a transient with the loss of all feedwater was considered to be high stress. Using these assumptions and the 138-day exposure period, the change in core damage frequency (CDF) was calculated to be less than 1.0E-6/yr.

For the Phase 3 SDP analysis, the Senior Reactor Analyst (SRA) also considered the risk contributions from internal flooding, external events, and large early release frequency. Only internal fire scenarios were determined to contribute to the risk significance of this finding. The 11 TDAFWP was the only credited means of decay heat removal in the licensee's Appendix R safe shutdown analysis for 10 different fire areas. The licensee's Individual Plant Examination for External Events (IPEEE) results and the NRC's Risk Assessment of Operational Events (RASP) Handbook for External Events were used as the best available information to estimate the fire risk contribution associated with the unavailability of the 11 TDAFWP.

For fire scenarios that do not involve control room evacuation, the same recovery human error probability (HEP) used in the internal events analysis was applied, since operators have appropriate indications and annunciators to implement the abnormal operating procedure in the control room. However, recovery of the pump would be different and more complex for fire scenarios involving control room evacuation. Licensee Procedure F5, "Control Room Evacuation (Fire)" directed operators to trip the reactor and the main feedwater pumps prior to evacuating the control room and proceeding to the hot shutdown panels. The procedure also directed operators to open breakers for the motor-driven AFW pumps, leaving only the 11 TDAFWP available for decay heat removal. Since the 11 TDAFWP would have tripped due to the mispositioned discharge pressure switch manifold isolation valve, no auxiliary feedwater pumps would be available without further operator action.

Procedure F5 provided direction to the operator to locally operate the 11 TDAFWP. If it was not running, the operator was directed to take action to bleed off the air supply to the turbine steam supply valve. This action failed the valve open and allowed the turbine to roll and start the pump if the pump had previously tripped from the low discharge pressure trip signal.

The recovery actions were directed to be performed by the Unit 1 Shift Supervisor who would be stationed at the Hot Shutdown Panels in the Auxilairy Feedwater Pump Rooms. This individual was first tasked with making the decision to evacuate the control room; assure appropriate notifications are made; and determine if self-contained breathing apparatus use is required. The Unit 1 Shift Supervisor was responsible for operating both the Unit 1 and Unit 2 TDAFWPs and directing operators in the plant performing other manual actions. Due to the heavy workload of the operator, complexity of the procedure, high stress of the postulated scenario, and limited experience with this procedure, the SRA determined that the failure probability for manual plant shutdown outside the control room would be increased because of this finding.

To obtain a quantitative estimate of the delta CDF, the SRA reviewed the top 100 cut sets submitted with the licensee's IPEEE analysis. The nominal failure probability for manual shutdown outside the control room (SHTDWN-OUT) was 6.4E-2. The SRA used SPAR-H to estimate a HEP for shutdown outside the control room given the performance deficiency. Assuming that the actions involve high stress, high complexity, low experience/training, and poor work processes (the Shift Supervisor was responsible for recovering the pump), the SRA calculated an action HEP of 0.13. This estimate was approximately double the nominal failure probability. Using this value as the failure probability for manual shutdown outside the control room for evacuation scenarios and a pump non-recovery probability of 2.2E-2 for other fire scenarios, the top 100 cut-sets were recalculated for an exposure period of 138 days. The delta CDF was estimated to be approximately 1.6E-6/yr.

The RASP external events handbook for internal fires was also used to evaluate the fire risk as a sensitivity analysis because of the uncertainty in the frequency of fires leading to control room evacuation scenarios. Since the dominant fire risk sequences from the licensee's IPEEE were fires involving control room evacuation; only those scenarios were addressed. These scenarios involved fires in the control room and relay room. Using the RASP handbook data on initiating event frequencies and non-suppression probabilities, the SRA confirmed that the change in core damage frequency from internal fires was above the 1.0E-6 threshold for a low to moderate safety significance (White) finding.

The result of the Phase 3 SDP analysis was a delta CDF of 1.6E-6/yr, considering both contributions from internal events and internal fire scenarios. The licensee performed a risk evaluation of the internal events contribution and the result was similar to the NRC's. The licensee had not yet completed an evaluation of the fire risk contribution.

The inspectors determined that the performance deficiency affected the crosscutting area of Human Performance, having resources components, and involving aspects associated with ensuring complete, accurate and up-to-date design documentation, procedures, work packages, and correct labeling of components. [H.2.(c)]

Enforcement

Technical Specification 3.7.5 states, in part, that two auxiliary feedwater trains be operable during plant operation in Modes 1, 2, and 3. Additionally, TS 3.7.5.B states, in part, if one auxiliary feedwater train is inoperable in Modes 1, 2, and 3, the affected train be restored to operable status within 72 hours or place the plant in Mode 3 within 6 hours and Mode 4 within 12 hours. Contrary to this requirement, as a result of the 11 TDAFWP pump's discharge-low-pressure pressure switch being isolated for approximately 138 days, the pump was inoperable for a time period which significantly exceeded the time allowed by TSs. For Unit 1, this is an apparent violation of TS 3.7.5 pending the completion of the final significance determination. (AV 05000282/2008008-01)

.4 Evaluation of the Root Cause Report Associated with the Reactor Trip

a. Inspection Scope

The inspectors monitored the licensee's root cause team activities and reviewed the final Root Cause Evaluation Report, "U1 OT∆T RX Trip," associated with CAP 1145953.

b. Findings and Observations

The inspectors noted that the licensee's root cause team used industry accepted root cause evaluation tools (i.e., Toubleshooting/Failure Analysis, Barrier Analysis, Event and Causal Factor Charting, Why Staircase, Fault Tree Analysis). The inspectors also noted that the licensee's root cause team was comprised of multi-disciplined individuals from systems engineering, electrical maintenance, and operations.

The licensee determined that the equipment root cause was that the 1TC-405L FΔQ proportional controller failed high due to a failure of a solid-state device within the controller. The licensee also concluded that the organizational root cause was due to lack of previous Foxboro H-Line component failures that had adverse consequences. Prairie Island did not adequately prioritize or apply the human resources necessary to develop and implement a preventive maintenance strategy for the components within the reactor protection and control system. The SIT determined that the licensee's efforts to identify the root causes associated with this event were adequate.

The SIT reviewed the licensee's immediate corrective actions and found them to be acceptable. Additionally, the Team reviewed the corrective actions to prevent recurrence and additional long-term corrective actions and determined, if the licensee fully implemented the corrective actions in a timely manner, the corrective actions would appropriately address the root causes for this event.

This inspection also represented the completion of one maintenance effectiveness (71111.12) inspection sample.

No findings of significance were identified.

.5 Evaluation of the Root Cause Report Associated with the Failure of the 11 Turbine-Driven Auxiliary Feedwater Pump Failure-to-Run Upon the Receipt of a Valid Demand Signal

a. Inspection Scope

The inspectors monitored the licensee's root cause team activities and reviewed the final Root Cause Evaluation report, "11 Turbine-Driven Auxiliary Feedwater Pump Discharge Pressure Switch Manifold Isolation Mispositioning," associated with CAP 1146005.

b. Findings and Observations

The inspectors noted that the licensee's root cause team used industry accepted root cause evaluation tools (i.e., Why Staircase, Barrier Failure Analysis, Failure Mode Analysis, Event and Causal Factor Charting). The inspectors also noted that the licensee's root cause team was comprised of multi-disciplined individuals from engineering, maintenance, and operations.

The licensee determined that the root cause for this event was inadequate configuration controls for components that have the potential to adversely impact the design function of safety related structures, systems and components. The SIT determined that the licensee's efforts to identify the root cause associated with this event were adequate.

The SIT reviewed the licensee's immediate corrective actions and found them to be acceptable. Additionally, the Team reviewed the corrective actions to prevent recurrence and additional long-term corrective actions and determined, if the licensee fully implemented the corrective actions in a timely manner, the corrective actions would appropriately address the root causes for this event.

No findings of significance were identified.

.6 <u>Review Procedures Associated with the Turbine-Driven Auxiliary Feedwater Pump to Assess Procedural or Testing Inadequacies Which May have Contributed to the Failure of the Pump</u>

a. <u>Inspection Scope</u>

The inspectors reviewed surveillance procedures, planned maintenance activities, operational line-up procedures, administrative procedures, and corrective action documents to identify issues that may have contributed to the configuration control issue, which resulted in the 11 TDAFWP failure to run upon receipt of a valid start signal.

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

The inspectors determined that the last activity that required the manipulation of the manifold isolation valve for the 11 TDAFWP discharge pressure switch was SP 1234A, "11 Auxiliary Feedwater Pump Suction and Pressure Switches Calibration," which was completed on February 23, 2008. Although several other surveillances required the operation of components in the general vicinity of the manifold isolation valve, the inspectors did not identify any additional activities that required manipulation of the valve during February 23, 2008, to July 31, 2008.

The inspectors noted the following licensee weaknesses that may have contributed to the configuration control issue associated with the mis-positioned manifold isolation valve:

- In general, instrument manifolds and associated manifold valves at Prairie Island were not labeled with a means of permanent identification.

- Instrument and control technicians identify manifolds by tracing sensing lines back from the applicable instrument to its associated manifold. This identification method and instructions describing how to operate each type of manifold, including how to identify the function of valves on each manifold, was covered as part of instrument and control technician training.

- A double standard existed at Prairie Island regarding how a component must be identified prior to its operation. Operators were required to positively identify a component, by means of an approved label, prior to operating a component. Instrument and control technicians were not held to the same standard, and routinely operate unlabeled instrument manifolds and associated valves.

- The licensee did not positively control minor components that could impact the performance of safety related equipment. A specific example of this was that, even though the root valve for the 11 TDAFWP low discharge pressure switch was locked and positively controlled via licensee processes, the manifold isolation valve, which can perform the same isolation function and is positioned between the root valve and the pressure switch, had no positive means to ensure that it remained open.

The inspectors reviewed the licensee's immediate and long term corrective actions (CAP 1146005) associated with addressing the issues described above and determined that the scope and extent of condition of the corrective actions were appropriate to address these issues.

No findings of significance were identified.

.7 Licensee's Actions to Immediately Assess the Extent-of -Condition Associated with the 11 Turbine-Driven Auxiliary Feedwater Pump Configuration Control Issue

a. Inspection Scope

The inspectors reviewed the licensee's extent of condition evaluation associated with the configuration control issue that resulted in the isolation of the 11TDAFWP discharge pressure switch. The inspectors evaluated the licensee's immediate and interim corrective actions, associated with the licensee's extent-of-condition evaluation, as they specifically pertained to this event.

b. Findings and Observations

The inspectors reviewed documentation associated with the licensee's immediate and interim corrective actions, as they relate specifically to auxiliary feedwater and on how they relate to similar components associated with other safety-related systems at Prairie Island. These corrective actions included:

- Valve lineups on the auxiliary feedwater system were completed by Operations and Instrument & Controls Departments;
- Surveillance testing was performed on the 11 TDAFWP to verify pump operability;
- Surveillance and post maintenance testing was performed on the 11 TDAFWP discharge and suction pressure switches to verify switch functionality;
- The suction and discharge pressure switch manifold isolation valves for all four auxiliary feedwater pumps were lock-wired in the open position; and
- The licensee performed a sampling of similar manifold valve positions located in other safety related systems.

The inspectors determined that the scope of the initial assessment of the extent-of-condition associated with this event and related corrective actions were adequate.

This inspection also represented the completion of one post maintenance test (71111.19) inspection sample.

No findings of significance were identified.

.8 Licensee's Immediate Corrective Actions and Planned Long Term Corrective Actions to Prevent Recurrence for Both the Reactor Trip and the Failure of the Turbine-Driven Auxiliary Feedwater Pump

a. Inspection Scope

The inspectors reviewed the adequacy of the licensee's immediate, interim corrective actions, corrective actions to prevent recurrence, and long term corrective actions associated with the reactor trip and the failure of the 11 TDAFWP to run.

b. Findings and Observations

The inspectors determined that the licensee's immediate and interim corrective actions were adequate to address the short-term challenges presented by the reactor trip and configuration control issue associated the 11 TDAFWP.

The SIT evaluated both events, reviewed their associated root cause evaluation, and evaluated the licensee's proposed corrective actions to prevent recurrence. For the reactor trip event, the corrective actions to prevent recurrence included:

- Replace or refurbish all flux tilt penalty ($F\Delta Q$)proportional controllers;
- Develop and implement a preventive maintenance strategy for the Foxboro H-Line components in the reactor protection and control system; and
- Ensure a life cycle management plan for the reactor protection and control systems was implemented to ensure timely preventive replacement of the Foxboro H-Line components.

For the failure of the TDAFWP to run, the most significant corrective action to prevent recurrence was to utilize a multi-phase process to conduct a comprehensive review of the licensee's configuration control standards. As part of this effort, the licensee will:

- Develop a process to review safety related systems to determine if there are any small components that may adversely affect the function of a safety-related system structure or component (SSC);
- Perform a trial of the methodology on a significant safety related system; and
- Complete this process to systematically identify all components that may adversely affect safety related SSCs for each safety related system.
- Implement necessary changes per the process that was developed.

The inspectors noted that the corrective actions to prevent recurrence for each of these events presented a significant challenge to the licensee to implement. The SIT determined that if the licensee fully implemented these corrective actions in a timely manner, the corrective actions would appropriately address the causes of each event.

No findings of significance were identified.

.9 <u>Circumstances Surrounding the Notice of Unusual Event Declared for the Release of Toxic Gases (Hydrazine) Deemed Detrimental to Normal Operation of the Plant and Evaluation of the Root Cause Event Report Associated with this Event</u>

a. <u>Inspection Scope</u>

The inspectors used direct observation of the event and subsequent licensee activities in conjunction with reviews of logs and the sequence of events, and personnel interviews to assess the circumstances associated with the event. Additionally, the inspectors monitored the licensee's root cause team activities and reviewed the final Root Cause Evaluation report, "Hydrazine NUE," associated with CAP 1146374.

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

Members of the resident staff observed the licensee's response to the event from inside the control room. Overall, the NOUE classification was declared in a timely manner and was appropriately classified in accordance with the station's emergency plan.

The inspectors noted that the licensee's root cause team used industry accepted root cause evaluation tools (i.e., Change Analysis; Event and Causal Factor Charting; Why Staircase). The inspectors also noted that the licensee's root cause team was comprised of multi-disciplined individuals with backgrounds in health physics, chemistry, radiation protection, and performance assessment.

The inspectors confirmed that the addition of hydrazine to the feedwater system following the reactor trip was performed in accordance with Electirc Power Research Institute guidance and approved station procedures. However, the inspectors discovered that these procedures were vague regarding what to expect when adding hydrazine during times when the feedwater system was in a non-typical configuration. The inspectors noted that even though existing chemistry procedures specifically identified that the existing main condenser status and feedwater lineup was not typical, no additional guidance was provided to the chemist on how the secondary plant would behave differently based on that non-typical configuration. The objective of the hydrazine addition to the feedwater system was to lower oxygen concentration by maintaining an 8 to 1 ration of hydrazine to oxygen, but consideration was not made as to how the non-typical configuration would affect the reaction mechanism; in this case, the generation of airborne hydrazine/ammonia.

The inspectors noted that the timely identification of actual levels of hydrazine/ammonia present in the lower levels of the Unit 1 turbine building was hampered by the chemist's lack of understanding associated with the air sampling equipment limitations. The equipment used to sample for hydrazine was adversely impacted by the presence of ammonia. The licensee concluded that if test equipment without a cross-sensitivity to ammonia interference had been used; the airborne chemical levels would have been appropriately characterized, eliminating the need for an evacuation of the turbine building and declaration of a NOUE.

The SIT reviewed the licensee's immediate corrective actions and found them to be acceptable. Additionally, the Team reviewed the corrective actions to prevent recurrence and additional long-term corrective actions and determined, if the licensee fully implemented the corrective actions in a timely manner, the corrective actions would appropriately address the root causes for this event.

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 6, 2008, the inspectors presented the inspection results to Mr. M. Wadley and members of his staff, who acknowledged the findings. The licensee acknowledged the information presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

No interim exits were conducted.

ATTACHMENTS:
1. SUPPLEMENTAL INFORMATION
2. TIMELINE OF EVENTS UNIT 1
3. SPECIAL INSPECTION TEAM CHARTER

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Wadley, Site Vice President
S. Northard, Plant Manager
C. Mundt, General Supervisor I&C Maintenance
S. Nelson, Fleet RP/Chemistry Manager
R. Hite, RP/Chemistry Manager
M. Kent, General Supervisor, RP
L. Clewett, Operations Manager
M. Schmidt, Maintenance Manager
S. Myers, Design Engineering Manager
S. Lappegaard, On-Line Work Manager
J. Callahan, Emergency Preparedness Manager
J. Muth, Nuclear Oversight Manager
E. Weinkam, Director, Nuclear Licensing
J. Anderson, Regulatory Affairs Manager
M. Davis, Regulatory Compliance Analyst

Nuclear Regulatory Commission

R. Skokowski, Chief, Branch 3
S. Thomas, Senior Resident Inspector [Monticello]
K. Stoedter, Senior Resident Inspector [Prairie Island]
P. Zurawski, Resident Inspector [Prairie Island]
D. Betantcourt, Reactor Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000282/2008008-01	AV	11 TDAFWP Inoperable for a Time Period Which Significantly Exceeded Time Allowed by TS

Closed

None

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather, that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

WORK ORDERS

Number	Description or Title	Date or Revision
00365604	Red Channel OTDT Failure Investigation	January 31, 2008
55698-02	EC Power Ascension Test	8
00365655	Investigation of 11 TDAFW Pump Trip	

CORRECTIVE ACTION PROGRAM DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
01145953	Red Channel Setpoint Failed Low Causing Reactor Trip	
00866960	Top Ten Equipment List Addition – Foxboro H-Line	
01146430	Potential Adverse Trend in Manifold Valve Operation	
01145943	11 AFW Pump Started and then Tripped	
01145964	11 AFWP Trip after Plant Trip	
01145996	Temporary Oil Lift Pump had Inadequate Pressure	
01146005	Mispositioned Block Valve on 11 TDAFWP	
01147573	RPIP 3005 Procedure Compliance Issue	
01010095	Benchmark Industry Regarding Labeling of Instrument Valves	
01146889	USAR AFW Time Critical Actions for MFW/MSL Break Question	
01146027	CC Piping Adjacent to HELB Location in Unit 2 Turbine Building	

CORRECTIVE ACTION PROGRAM DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
01146120	U1 Secondary Exceeds EPRI Guidelines for Oxygen/Hydrazine Condensate Oxygen is 6500ppb	
01146304	NUE HU3.1- Potential Plant Equipment Impact from Hydrazine	
01146374	U1 NOUE: High Airborne Hydrazine Levels on 695' EL Turbine Building	
01146357	Minor Errors in NRC Notification Forms for Hydrazine Event	
AR 01146974	Prompt Investigation for NUE: Airborne Hydrazine Excursion	

PROCEDURES

Number	Description or Title	Date or Revision
SP 1003	Analog Protection Functional Test	63
SP 1002A	Analog Protection System Calibration	37
C1.6A.1-1	Unit 1 – Integrated Operations Checklist Prior to Heatup, First Floor Turbine Building	10
C28-7	Auxiliary Feedwater System Unit 2	49
C1.6A.1-2	Unit 2 – Integrated Operations Checklist Prior to Heatup, First Floor Turbine Building	9
C1.6A.3-1	Unit 1 – Integrated Operations Checklist Prior to Heatup, First Floor Auxiliary Building	8
1ES-0.1	Reactor Trip Recovery	23
C47010-0205	11 TD AFWP Lo Suct or Disch Press Trip	38
1C28.1 AOP4	Restarting Unit 1 AFWP after Low Suction/Discharge Pressure Trip	3
SWI O-35	Emergency Operating Procedure Verification, Validation and Maintenance	6
SP 1102	11 Turbine-Driven AFW Pump Monthly Test	89
SP 1054	Turbine Stop, Governor, Reheat Stop and Reheat Intercept Valve Exercise.	35
C28-1	Auxiliary Feedwater System – Unit 1	44

PROCEDURES

Number	Description or Title	Date or Revision
ICPM 1-416	11 Turbine Driven Aux Feed Pump Instruments Calibration	3
D14.4 AOP1	Chemical Leak or Spill Implementing Procedure	8
SP 1103	11 Turbine-Driven Auxiliary Feedwater Pump Once Every Refueling Outage Shutdown Flow Test	45
SP 1193	Cycling AFWP and CLG Water MV's	33
SP 1376	AFW Flow Path Verification Test after each Cold Shutdown	11
SP 1355A	Train 'A' AFW Check Valve Testing	11
SP 1234A	11 Aux Feedwater Pump Suction and Discharge Pressure Switches Calibration	6
SP 1100	12 Motor Driven AFW Pump Monthly Test	75
5AWI 3.10.5	Plant Equipment Labeling	13
RPIP 3002	EPRI Secondary Water Chemistry Guidelines	17
RPIP 3000	Plant Startup Guidelines	12
RPIP 3005	Secondary Chemical Feed System	14
RPIP 3001	Plant Shutdown Guidelines	10
RPIP 3303	Airborne Chemical Determination	4

REFERENCES

Number	Description or Title	Date or Revision
N/A	Top 10 Equipment List; Foxboro H-Line	July 15, 2008
N/A	Reactor Trip Report for July 31, 2008, Reactor Trip	
NF-39222	Flow Diagram – Unit 1 Feedwater System	76
NF-40312-1	Interlock Logic Diagram - Unit 1 Auxiliary Feedwater System	76
N/A	LCO Entry Report for 12 MDFP for the Time Period of February 1, 2008 to July 31, 2008	
N/A	Strategic Water Chemistry Plan for PINGP Secondary Water Chemistry	8
N/A	RPCHEM On-the-Job Training and Task Performance Evaluation Review Guide	8

REFERENCES

Number	Description or Title	Date or Revision
N/A	RPCHEM On-the-Job Training and Task Performance Evaluation Guide	0

LIST OF ACRONYMS USED

CAP	Corrective Action Program
CDF	Core Damage Frequency
HEP	Human Error Probability
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination for External Events
MD	Management Directive
NCV	Non-Cited Violation
NOUE	Notice of Unusual Event
NRC	Nuclear Regulatory Commission
OTΔT	Overtemperature Delta Temperature
RASP	Risk Assessment of Operational Events
SSC	System Structure or Component
SDP	Significance Determination Process
SIT	Special Inspection Team
SRA	Senior Reactor Analyst
TDAFWP	Turbine-Driven Auxiliary Feedwater Pump
TS	Technical Specification

Historical Timeline of Events for THE Reactor trip, 11 Turbine-Driven Auxiliary feedwater pump fail to run, and the turbine building hydrazine unusual event

DATE, 2008	TIME	DESCRIPTION
February 23	1833	SP 1234A Suction/Discharge Pressure Switch Calibration
March 8		PM 3132-1-11 11 TDAF Pump Minor Periodic Maintenance
March 11	1500	C1.6A.1-1 Integrated Operation Checklist Prior to Heat Up Includes the Verification of 17700 Bottom Isolation in the Open Position
March 12		SP 1301- 11 TDAFW Pump Auto Start and Functional Refueling Outage Test. Closed and then Open 17704 Bottom Isolation Valve (in the vicinity of 17700)
March 26	2226	SP 1102 - 11 TDAFW Pump Monthly Test
May 1	0049	SP 1102 - 11 TDAFW Pump Monthly Test
May 29	0441	SP 1102 - 11 TDAFW Pump Monthly Test
June 26	0423	SP 1102 - 11 TDAFW Pump Monthly Test
July 31		SP 1003 Analog Protection Functional Test [yellow channel bistables in per SP]
	0817	Unit 1 Reactor Trip and 11 TDAFW Pump Auto Start Operators Enter 1E-0
	0818	11 TDAFW Pump Low Discharge Pressure trip (42 sec run) Unit 1 Enters Mode 3
	0819	Operators Transition to 1ES-0.1, Reactor Trip Recovery
	0821	11 TDAFWP Low Suction/Discharge Pressure Trip Annunciator. Operator Dispatched
	0822	After Trip of AFWP, with Severe Weather, PRA is Yellow for both Unit 1 and Unit 2
	0826	Attachment J of 1E-0, Isolate Unit 1 MSR's, is Complete 0905 Operators Transition to 1C1.3, Unit 1 Shutdown
	0855	12 MDAFW Pump Stopped and SG Level Control via Main FW via Bypass Valves
	0914	RP Tour of Aux Building Indicated no Alarms, Leaking Water or Steam
	0915	11 TDAFW Pump Reported to have Auto Started and Run for Approximately 50 Seconds
	1012	Operators Notify NRC of Reactor Trip per 10 CFR 50.72
	1055	11 TDAFW Pump Area Quarantined
	1323	Completed C28-2 (U1 AFW System Checklist) Found Manifold Block Valve for 17700 Closed

	1400	Commenced Breaking U1 Condenser Vacuum
	1500	SP 1102 - 11 TDAFW Pump Monthly Test
August 1	0619	SP 1234A Suction/Discharge Pressure Switch Calibration Close then Open 17700 Bottom Isolation
August 2	1200	FW Chemistry: 9575 ppb Oxygen; 31132 ppb N_2H_4 ; Condenser Chemistry: 7424ppb Oxygen
	1543	U1 Reactor Entered Mode 2
	1738	U1 Reactor Critical
	1815	Reactor Power at Point of Adding Heat
	2000	FW Chemistry: 9032 ppb Oxygen; 37410 ppb N_2H_4 ; Condenser Chemistry: 7247 ppb Oxygen
	2007	Initiated Condenser Vacuum
	2133	U1 Entered Mode 1
	2315	FW Chemistry: 165 ppb Oxygen; Condenser Chemistry: 163 ppb Oxygen
August 3	0028	Started Rolling U1 Main Turbine to 600 rpm
	0040	Started Rolling U1 Main Turbine from 600 rpm to 1800 rpm
	0125	Reactor Power 8%
	0208	Reactor Power 15%
	0341	Duty Chemistry Reports Positive Hydrazine Air Sample Results from Unit 1 Condenser Pit and the 695' Level Top of a Stairway into Condenser Pit (value less than IDLH). Chemist Placed Barriers to Stop Access.
	0352	Declared NOUE (HU3.1)
	0356	Announcement Made to Evacuate Unit 1 695 Turbine Building and Condenser Pit
	0403	Air Sample Results from Hydrazine: 695' by Old Admin Building Door 0.25 ppm; 715' Outside Access Control 1 ppm; 735' Next to HP Turbine 3 ppm; Control Room < 0.1 ppm
	0416	NRC Resident Inspector and Duty Station Manager Notified of NOUE Declaration HU3.1 due to High Levels of Hydrazine in Unit 1 Turbine Building Sump Area
	0440	Chemist Reports no Detectible Hydrazine in Air Sample outside D1 and D2
	0506	Chemist Air Samples Show that 715’ and 735’ Levels of Unit 1 Turbine Building had Stayed Habitable

	0647	All Hydrazine Samples on the 735' Unit 1 Turbine Building are Below the 1.00 ppm Permissible Exposure Limit (PEL); Highest was 0.75 ppm at the HP Turbine. Normal Access Restored to 735' Unit 1 Turbine Building.
	0818	Access to the 695' Unit 1 Turbine Building Restored with the Exception of the Southwest Corner Marked with Danger Tape.
	0910	Entered Loss of Hydrazine Feed Condition (PINGP 1597 & PINGP 1537; RPIP-3002) for Securing Hydrazine Addition
	1040	Hydrazine air samples are as follow: 735' HP Turbine area and 715' by 15 A FWH < 0.1 ppm; 715' by Hoggers 0.5 ppm; 695' on top of stairs at SW corner of condenser pit 2ppm; 675' north side at bottom of the stairs 0.75 ppm; 675' by Amertap control panel 3 ppm; sump area under catwalk 0.75 ppm; South side of Condenser pit by the Heater Drain Pumps < 0.1 ppm; and Next to Turbine Building Sump Bay # 2 3 ppm
	1115	Entered Action Level 1 for Loss of Hydrazine. Hold at < 30% Power for Low Oxygen Levels and Hydrazine
	1200	Chemistry Pulled Liquid Dample from Both Unit 1 Turbine Building Sump Bays for Hydrazine Analysis. Airborne Level at #2 Bay was < 0.1 ppm
	1337	Liquid Samples Reported as 18 ppb (bay 1), 21 ppb (bay 2) and 53 ppb (bay 3). No Action Required for These Concentrations.
	1349	Started Adding Hydrazine to Unit 1 FW System. Walkdowns of Hydrazine Addition Piping Indicates no Visual Leakage. Access Limited to 695' Unit 1 Turbine Building Until Surveys Completed
	1420	Surveys of 695' U1 Turbine Building Indicate no Levels Above 0.1 ppm and All Postings of that Level Removed
	1430	Hydrazine Air Samples 30 Minutes after Initiating Injection to Feedwater System were: 695' at top of Condenser Pit Stairway SW Corner < 0.1ppm, Postings Taken Down from Entire 695' Level and Cleared for Normal Access; 675' by Unit 1 Turbine Building Sump Bay 2 was 5 ppm; Amertap Control Panel 1 ppm; MCC 1EA Bus 2 2.0 ppm; and Chemist Reported that the Ammonia Smell was Limited to Small Pockets of Stagnant Air
	1448	Exited Action Level 1 and loss of Hydrazine Conditions. Exited Chemical Hold on Power
	1530	Commenced Power Accession to 50%

	1618	Ventilation Fans Started on the North and South Sides of Unit 1 Condenser Pit for Mixing
	1629	Commenced power accession to 70%
	1649	Hydrazine Air Samples are as Follows: Airborne near Turbine Building Sump Bay 2 < 0.1 ppm; and near MCC 1EA Bus 2 0.3 ppm Liquid samples Reported as 8.2 ppb (bay 1), 7.7 ppb (bay 2) and 13.8 ppb (bay 3)
	1709	Maintenance Workers Entered Unit 1 Condenser Pit to Place Fans in Pit.
	2220	Exited the Notification of Unusual Event (NOUE) HU3.1, Release of Toxic or Flammable Gases after 3 Consecutive Samples Returned Less than Detectable Hydrazine (< 0.1 ppm)

August 1, 2008

MEMORANDUM TO: Christopher S. Thomas, Senior Resident Inspector
Monticello Station

FROM: Cynthia D. Pederson, Director
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION CHARTER FOR REACTOR TRIP AND TURBINE-DRIVEN AUXILIARY FEED WATER FAILURE ON JULY 31, 2008

On July 31, 2008, at 8:17a.m., the Unit 1 reactor tripped at the Prairie Island Site. At the time, the yellow train of reactor trip system (RTS) instrumentation was out of service for RTS testing. The red channel then received an overtemperature ΔT signal. This met the 2 of 4 channel logic which caused the reactor trip. At this time the cause of the overtemperature ΔT signal on the red channel is unknown, but the licensee believes it was a spurious signal.

Following the reactor trip, the turbine driven auxiliary feedwater pump started and ran for approximately 50 seconds before tripping on low suction/pressure. The pressure switch for discharge pressure was found to be closed. The closure of this switch caused the pump to trip as part of the pump protection features. The last time a surveillance test was performed on the turbine driven auxiliary feedwater pump was over 30 days before on June 21, 2008, however the discharge pressure switch impact may not have been challenged during this surveillance test.

The sequence of events and the cause of the problem are being investigated by the licensee. Based on the deterministic criteria provided in Management Directive 8.3, “NRC Incident Investigation Program, ” the incident met MD 8.3 criterion h, “Involved questions or concerns pertaining to licensee operational performance.” A Region III Senior Reactor Analyst completed a SPAR model event assessment using a transient initiating event and failure of the auxiliary feed water system to run and the pre-existing maintenance unavailability of instrument air compressor 121. The assessment resulted in a preliminary Incremental Conditional Core Damage Probability (ICCDP) value of approximately 5.2E-6.

Accordingly, based on the deterministic and risk criteria in MD 8.3, and as provided in Regional Procedure 8.31, “Special Inspections at Licensed Facility,” a Special Inspection Team will commence an inspection on July 31, 2008. The Special Inspection Team will be led by you and will include Karla Stoedter, the Senior Resident Inspector, Prairie Island, and Diana Betancourt, Reactor Engineer, Region III.

CONTACT: Richard Skokowski
630-829-9620

The special inspection will determine the sequence of events, and will evaluate the facts, circumstances, and the licensee's actions surrounding the July 31, 2008 incident. The specific charter for the Team is enclosed.

Enclosure: As Stated

cc w/encl: J. Caldwell, Regional Administrator, Region III
M. Satorius, Deputy Regional Administrator, Region III
H. Peterson, DRS, Chief, Operator Licensing Branch
K. Stoedter, SRI, Prairie Island
P. Zurawski, RI, Prairie Island
D. Betancourt-Roldan, Reactor Engineer, RIII

PRAIRIE ISLAND SPECIAL INSPECTION CHARTER

This Special Inspection Team is chartered to assess the circumstances surrounding the deviation from the required safety system lineup of the auxiliary feed water system during a reactor shutdown on July 31, 2008. The Special Inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection," and will include, but not be limited to, the items listed below.

1. Identify the time-line for the event. Include plant conditions, system line ups, and operator actions.

2. Review the licensee's post-trip review to determine the cause of the reactor trip. Independently review plant data and records to confirm the adequacy of the licensee's assessment, and corrective actions.

3. Review the circumstances surrounding the failure of the turbine-driven auxiliary feedwater pump, including the most likely cause of the pump failure; the length of time the pump may have been in an unrecognized failed condition, and any potential for operators to recover the failed pump.

4. Determine if the licensee is performing a root cause for the reactor trip. As available, evaluate the scope, schedule, staffing and results of the licensee's root cause investigation.

5. Determine if the licensee is performing a root cause for the turbine-driven auxiliary feedwater pump failure. As available, evaluate the scope, schedule, staffing and results of the licensee's root cause investigation.

6 Review procedures for the turbine-driven auxiliary feedwater pump, including operational line-up procedures and testing procedures, to assess any procedural or testing inadequacies which may have contributed to the failure of the pump.

7. Determine if the licensee performed an extent-of-condition evaluation to assess if the contributing causes to the failure of the turbine-driven auxiliary feedwater pump have the potential to affect other safety-related equipment.

8. Review for adequacy the licensee's immediate corrective actions and planned long term corrective actions to prevent recurrence for both the reactor trip and the failure of the turbine-driven auxiliary feedwater pump.

Charter Approval

/RA/ R. Skokowski, Chief, Branch 3, DRP

/RA by G. Shear for/ C. Pederson, Director, Division of Reactor Projects