U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-282/94003; 50-306/94003(DRP)

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

Licensee: Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Facility Name: Prairie Island Nuclear Generating Plant

Inspection At: Prairie Island Site, Red Wing, MN

Inspection Conducted: March 5 through April 22, 1994

Inspectors: M. L. Dapas R. L. Bywater
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Approved By: Wayne Kropp, Chief
Reactor Projects Section 2A

5/6/94
Date

Inspection Summary

Inspection on March 5 through April 22, 1994 (Report No. 50-282/94003; 50-306/94003(DRP))

Areas Inspected: Routine unannounced inspection by resident inspectors and others of operational safety verification, onsite event followup, maintenance activities, surveillance activities, engineering and technical support, security, radiological controls, licensee followup on previously identified items, and licensee event report followup.

Results: Of the nine areas inspected, four violations were identified. One violation involved inadequate corrective action in response to a previously issued violation for removing essential support equipment from service (paragraph 3.a). One violation (no response required) involved an inadequate procedure for operation of the cooling water system pumps during post-maintenance testing (paragraph 6.h). One violation (non-cited) involved the failure to perform a fitness-for-duty (FFD) evaluation prior to granting unescorted access to a contract employee who had a positive FFD test result on record (paragraph 6.b). One violation (non-cited) involved the inoperability of a Technical Specification-required noble gas, radiation monitor (paragraph 6.j).

The following is a summary of the licensee's performance during this inspection period:

Operations

One violation was identified involving inadequate corrective action for removing essential support equipment (bus room No. 120 safeguards unit cooler) from service with no attendant entry into the appropriate Limiting Condition for Operation for the parent component (safeguards bus No. 120) (paragraph 3.a). The licensee's self-assessment efforts relative to this event have identified that improvements are needed in the methods the licensee uses to convey new information and requirements to the staff.

One violation was identified regarding an inadequate procedure for operation of the CL system pumps during post-maintenance testing (paragraph 6.h). The licensee's corrective action to prevent recurrence in response to a March 25, 1993, automatic start of No. 121 CL pump, was considered inadequate (paragraph 6.h). Licensee actions to preclude future automatic starts of No. 121 CL pump in various CL system configurations mainly because the starts are reportable per 10 CFR 50.72 and 50.73, require further evaluation (paragraph 2.b.1).

The licensee's decision to reduce power and take Unit 2 offline to effect repairs to the turbine electro-hydraulic control system, thereby eliminating the possibility of a turbine trip/reactor trip, reflected a conservative operating philosophy (paragraph 2.b.2). The licensee's recent efforts in the area of outage planning and management were considered a strength (paragraph 2.d).

Engineering and Technical Support

Several open items that required significant engineering involvement to adequately resolve, were closed during this inspection period (paragraphs 5 and 6).

Plant Support

One non-cited violation in the area of Security was identified regarding the failure to perform a fitness-for-duty (FFD) evaluation prior to granting unescorted access to a contract employee who had a positive FFD test result on record (paragraph 6.b). The licensee implemented comprehensive corrective actions in response to this event.

One non-cited violation was identified regarding the inoperability of the Radwaste Building ventilation system, noble gas monitor that was not identified during post-modification testing (paragraph 6.j).

DETAILS

1. Persons Contacted

Northern States Power Company

E. Watzl, General Manager, Prairie Island
#M. Wadley, Plant Manager
#K. Albrecht, General Superintendent, Engineering
G. Lenertz, General Superintendent, Maintenance
#D. Schuelke, General Superintendent, Radiation Protection and Chemistry
#J. Sorensen, General Superintendent, Plant Operations
#J. Goldsmith, Superintendent, Engineering-Nuclear Generation Services
#R. Fraser, Superintendent, Mechanical/Civil Engineering-Nuclear Generation Services
G. Miller, Superintendent, Technical Support
#A. Hunstad, Staff Engineer
R. Stenroos, Superintendent, Site Quality
J. Hill, Superintendent, Instrumentation and Controls Systems
J. Maki, Superintendent, Electrical Systems
M. Agen, Emergency Planning Senior Consultant
P. Ryan, Shift Manager
#L. Anderson, Shift Manager
M. Schmidt, Outage Manager
#S. Chezick, Nuclear Lead Plant Equipment and Reactor Operator
R. Mella, Production Engineer
J. Sawyer, Production Engineer
E. Eckholt, Nuclear Support Services
#J. Leveille, Nuclear Support Services
#G. Aandahl, Superintendent Design Standards

#Denotes those present at the management interview of April 20, 1994.

The inspectors also had discussions with other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, and electrical, mechanical and instrument maintenance personnel, and contract security personnel.

2. Plant Operations

Both units operated at full power throughout the inspection period except for March 27, 1994, when Unit 2 was taken offline to perform maintenance on the turbine electro-hydraulic control system. As of April 22, 1994, Unit 1 had operated for 429 continuous days.

a. Operational Safety Verification (71707, 71714, 93702)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, and observed shift turnovers. The inspectors verified operability of selected emergency systems, reviewed equipment control records, verified the proper return to service of affected components, conducted tours of the Auxiliary Building, Turbine Building and external areas of the plant to observe plant equipment conditions, including potential fire hazards, and to verify that maintenance work requests had been initiated for equipment in need of repairs.

No discrepancies were noted.

b. Onsite Event Followup (93702)

During the inspection period, the licensee experienced various events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that any required notification was correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

(1) At 6:59 p.m. (CST) on March 31, 1994, No. 121 cooling water (CL) pump automatically started on low header pressure following post-maintenance testing of No. 12 diesel-driven CL pump. At the time of the event, No. 121 CL pump was not aligned for safeguards operation and No. 11 motor-driven CL pump was running to supply CL to the A supply header. During the performance of the monthly surveillance test earlier in the day, No. 12 CL pump exhibited fluctuations in discharge pressure due to hunting of the governor. The licensee adjusted the governor compensation and then started No. 12 CL pump to check the compensation setting. Following this check, the licensee secured the pump. When the pump was secured, No. 121 CL pump did not automatically start. The licensee then closed the discharge isolation valve for No. 12 CL pump and started the pump to verify that it would not overspeed. After completing this evolution, the licensee opened the pump discharge isolation valve and subsequently secured No. 12 CL pump. The resultant decrease in system pressure was sufficient to cause No. 121 CL pump to automatically start.

During the review of this event, the inspectors identified the following concerns/issues:

- The CL pump common discharge header, motor-operated isolation valves MV-32034, MV-32035, MV-32036, and MV-32037 were open prior to securing No. 12 CL pump in accordance with the CL system operating procedure C35 (refer to paragraph 6.h and i). This should have precluded No. 121 CL pump from automatically starting on low header pressure. However, at the time of the event, the licensee was in the process of bringing the cooling towers on line. This involves reducing the amount of circulating water which is discharged directly to the Mississippi river via the discharge canal and returning this flow to the intake canal after it has passed through the cooling towers. The intake canal provides water to both the circulating water system and CL system via intake bays in the plant screenhouse. As a result, the CL system inlet temperature was approximately 20 degrees higher than it normally is when the cooling towers are not in service. The licensee concluded that the higher inlet temperature resulted in increased CL system load and consequently reduced system operating pressure. The margin between normal system operating pressure and the auto-start setpoint for No 121 CL pump was thus reduced. The downward pressure spike in the system upon securing No. 12 pump was sufficient to cause No. 121 CL pump to auto-start.

- Although No. 121 CL pump was not aligned for safeguards operation, the licensee reported this event as an ESF actuation. The licensee subsequently retracted the 10 CFR 50.72 notification after deciding that this event was not reportable since No. 121 CL pump was not aligned for safeguards operation per Technical Specifications. This event indicates that the licensee's corrective action to prevent recurrence for the March 1, 1994 event discussed in paragraph 6.h, may not be effective for all CL system configurations. The inspectors discussed the March 31, 1994, event with the CL system engineer. The licensee is considering taking actions to preclude future automatic starts of No. 121 CL pump in various CL system configurations (e.g. placing the pump control switch in pull-out or installing a time delay in the pump start circuitry) in instances when the starts would be reportable per 10 CFR 50.72 and 50.73 criteria. The inspectors were concerned that taking these actions due to reportability concerns may not be prudent. The inspectors concluded that this event resulted from a unique set of circumstances, and as such, the licensee's previous corrective action to prevent automatic starts of No. 121 CL pump (refer to paragraph 6.h and i) appeared adequate.

(2) On March 16, 1994, a control room alarm was received indicating a problem with a backup power supply for the Unit 2 turbine electro-hydraulic control (EH) system. The licensee initiated an investigation and determined that the voltage output of the +15V secondary power supply in the EH system was low and that it might not function properly in the event of a failure of the primary +15V power supply. A failure of the primary power supply could potentially result in a turbine trip. The licensee concluded that it would be prudent to repair the power supply rather than wait until the next outage, and that the work should be performed at reduced power because there was some risk of initiating a turbine trip during work in the EH power supply racks. The licensee decided to perform the repair during a power reduction for turbine control valve (CV) testing. A CV test had originally been scheduled for March 13, but was postponed to March 27 in order to accommodate demands on the electrical distribution grid due to the unavailability of other generating units. The licensee determined that performing the power reduction, CV test, and EH power supply repair on March 27 would allow sufficient time to develop a thorough repair plan and accommodate existing demands on the electrical grid. The licensee considered it a low probability that the primary EH power supply would fail during the relatively short period of time before repairing the backup power supply. After further review, the licensee determined that the best course of action was to reduce power and take Unit 2 offline to effect repairs to the EH system, thereby eliminating the possibility of a turbine trip/reactor trip. The inspectors considered this a conservative operating decision.

On the night of March 26-27, 1994, the inspectors attended the pre-evolution briefing, and observed the Unit 2 power reduction, removal of the turbine-generator from service, and EH power supply replacement. The inspectors noted that the pre-evolution briefing was thorough. Instrumentation and control (I&C) personnel did not attend this initial briefing because their work was not scheduled to begin until Unit 2 was offline at approximately 3 a.m. However, when the I&C personnel did arrive onsite, another briefing was conducted with operations shift management and the workers. The EH system work was performed per WO 9402050-EH without incident. The +15V secondary power supply was removed and replaced with a refurbished power supply.

During the review of this event, the inspectors identified the following concerns/issues:

- Because of the potential for an inadvertent turbine trip while repairing the backup power supply, the licensee considered performing the repair when power was below the P-9 reactor protection system permissive setpoint to avoid initiating a reactor trip if a turbine trip should occur. If a turbine trip were to occur below the P-9 setpoint of 10 percent power, a reactor trip would not result. However, the licensee noted that plant operation below 10 percent power is not a routine activity and sustained operation at low power levels is particularly challenging. The licensee briefly considered raising its P-9 setpoint to a higher power level (20 percent) to allow more operational flexibility. The Technical Specifications (TS) allow a P-9 setpoint of 50 percent, however, the setpoint value specified in the Updated Safety Analysis Report is 10 percent. The inspectors reviewed correspondence between the NRC and the licensee regarding the P-9 setpoint and noted that the NRC granted a TS license amendment in 1979, prior to the Three Mile Island (TMI) accident, allowing a P-9 setpoint of 50 percent. After the TMI accident, the NRC required, through its issuance of NUREG 0737, "Clarification of TMI Action Plan Requirements", that licensees delay implementation of increased P-9 setpoints until they had analyzed what effect an increased value of P-9 could have on the probability of a pressurizer power operated relief valve (PORV) not reseating during an event. The licensee elected to maintain its P-9 setpoint at 10 percent and did not perform the subject analysis. In 1989, to facilitate testing its new digital feedwater control system, the licensee wrote safety evaluation No. 264 to demonstrate that increasing the P-9 setpoint to 20 percent did not constitute an unreviewed safety question. In their review of this safety evaluation, the inspectors concluded that it provided only a cursory, qualitative evaluation of the post-TMI PORV issue. The inspectors concluded that for the licensee to increase its P-9 setpoint, it would need to perform a more substantive safety evaluation that included a review of the PORV issue.

- While on a tour of the Auxiliary Building at approximately 5:30 a.m. before the unit was returned to service, the inspectors heard the Unit 2 loop B, main steam non-return check valve contact the valve seat several times. Upon returning to the control room to inquire what may have been the cause, the inspectors were informed by the operators that the steam dump valve to the condenser was not responding properly and could be causing pressure surges in the steam line, possibly resulting in non-return check valve closure. An operator had been dispatched to the condenser steam dump valve and he observed that the valve's position feedback linkage had lost a fastener and was no longer functioning properly. The operator found the fastener on the floor and while the control room operators used the steam generator PORVs to control steam pressure, the local operator replaced the fastener in the feedback linkage of the dump valve. An emergency work request was initiated to have I&C personnel repair or tighten the fastener as necessary. However, before this was accomplished, at approximately 8 a.m., the fastener came loose again, the feedback linkage was nonfunctional, and operators again controlled steam pressure with the PORVs until I&C personnel completed the repair. The unit was returned to service without further incident, reaching full power at about 10 a.m. on March 27.

The inspectors discussed the valve linkage problem with the Superintendent of I&C Systems Engineering with respect to a potential generic problem with control valve feedback linkages. The licensee's air operated valve engineer was reviewing the issue and the licensee did not identify any immediate operability concerns. The inspectors will continue to follow this issue.

c. Information Notice (IN) 89-77, Supplement 1

In response to a request from the NRC Region III Office, the inspectors reviewed the licensee's operating experience assessment (OEA) activities for IN 89-77, Supplement 1, "Debris in Containment Emergency Sumps and Incorrect Screen Configurations." In its OEA, the licensee reviewed plant drawings and determined that no unaccountable penetrations existed in the safeguards sump screens or curb. Also, the licensee visually verified that the as-built sump configuration was in accordance with plant drawings during a routine at-power inspection of the Unit 1 containment building.

d. Preparation for Refueling

The inspectors attended outage planning meetings and reviewed the licensee's ongoing preparations for the Unit 1 refueling outage, scheduled to begin in May 1994. Significant outage activities include:

(1) Refueling
(2) 10-year inservice inspection of the reactor vessel and other major systems
(3) Steam generator tube inspection and repair

(4) Completion of control room panel human factors upgrade modification
(5) Completion of electrical systems upgrade modification
(6) Preoperational testing of reactor coolant system drain path modification (self-limiting drain) and ultrasonic water level instrumentation
(7) Containment integrated leak rate test
(8) Generic Letter 89-10 motor-operated valve testing

The licensee has implemented an "Outage Windows" concept based upon reactor coolant system inventory conditions, to improve outage management. This should reinforce the licensee's current "shutdown safety assessment" program in ensuring that an adequate defense-in-depth is maintained for key safety functions. The licensee has incorporated lessons learned from the previous Unit 2 outage as evidenced by improvements in the areas of containment boundary control and work control. The inspectors considered the licensee's efforts in the area of outage planning a strength.

No violations, deviations, unresolved items, or inspection followup items were identified.

3. Maintenance Observation (71707, 37700, 62703)

Routine preventive and corrective maintenance activities were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications. The following items were considered during this review: adherence to Limiting Conditions for Operation while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed or reviewed during the inspection period:

a. On March 8, 1994, during performance of WO 9400867-EM-Q, the train B unit cooler in bus room No. 120 was secured, however, 480V safeguards bus No. 120 was not declared inoperable. This condition existed for approximately 15 minutes. An operations department daily order, issued on February 11, 1994, required that any work request that removed safeguards unit coolers or ventilation systems from service must explicitly address the operability of the associated equipment. With respect to removing bus room No. 120 train A unit cooler from service, the daily order required that bus No. 120 be declared inoperable and the action requirements of Technical Specification (TS) 3.7.B.6 be applied. This TS allowed bus No. 120 to be inoperable for 8 hours.

Bus room 120 contains the Unit 1 train B 480V safeguards bus No. 120, and train A event monitoring (EM) equipment for both units. Two unit coolers are installed in bus room 120, one from each train of the safeguards chilled water system. Both unit coolers are safety-related and each unit cooler is sized to remove the maximum postulated heat generation in the room; i.e., train A cooler (102A) to ensure EM equipment is operable, and train B cooler (102) to ensure bus No. 120 is operable.

The subject work order was written to implement an alteration to the train A EM equipment instrumentation racks, located in bus room 120. The alteration included the installation of ventilation louvers in the instrumentation rack cabinets to address EM equipment operability concerns due to high temperatures inside of the cabinets. Temperature effects on EM equipment are addressed in NRC Inspection Report 50-282/93008; 50-306/93008(DRP). After completion of the louver installation, an I&C technician installed test equipment to monitor cabinet interior temperature and bus room ambient temperature, and then secured unit cooler No. 102 with the intent of verifying that the cabinet louvers were effective in minimizing the temperature differential between the EM cabinet and the room. After securing No. 102 unit cooler, the I&C technician notified the control room that the cooler was out-of-service. The Unit 1 lead reactor operator noted that the February 11 daily order required that bus No. 120 be declared inoperable if unit cooler No. 102 was removed from service. Bus No. 120 had not been declared inoperable before the unit cooler was removed from service. The Unit 1 lead reactor operator and shift supervisor discussed the condition and ordered the subject cooler returned to service. A late entry was made in the Unit 1 limiting condition for operation (LCO) log indicating that the 8 hour LCO for bus No. 120 had been entered during the approximately 15 minutes that unit cooler No. 102 was secured.

The NRC issued a violation in Inspection Report 50-306/93015(DRP) for securing safeguards heat removal equipment from service without addressing the operability of the parent system. One of the licensee's actions in response to this issue was the issuance of an operations department daily order on July 30, 1993. The daily order contained a list of equipment heat removal systems and the associated TS LCOs that applied if specific systems were removed from service. In order to provide personnel outside of the operations department information and increased awareness of heat removal systems as essential support equipment, the General Superintendent of Plant Operations wrote a letter to all engineers and maintenance supervisors highlighting the issue and enclosed a copy of the July 30 daily order. The latest revision of the daily order was issued February 11, 1994, but it was not distributed to the engineering staff or maintenance supervisors. With respect to the March 8 event, the subject work request did not address operability of safeguards bus No. 120, and the Unit 1 shift supervisor granted approval to start work although the February 11 daily order identified that an LCO entry for bus No. 120 was required if unit cooler No. 102 was secured. The inspectors concluded that, based upon the previously-issued violation, the licensee should have had adequate corrective actions in place to prevent the unintended removal from service of an essential support system. The failure to take adequate actions to correct conditions adverse to quality is a violation of 10 CFR 50, Appendix B, Criterion XVI (50-282/94003-01; 50-306/94003-01(DRP)).

The inspectors evaluated the licensee's self-assessment efforts associated with this event. The licensee initiated a nonconforming activity report and Error Reduction Task Force review to identify root causes and to recommend appropriate corrective actions. The inspectors validated the licensee's identified root causes through interviews with the EM system engineer, modification engineer, and selected operations department staff. Staff engineers were not adequately aware of the inter-relationship between unit coolers and the operability of safety-related equipment in the bus room, and operations department personnel did not apply the requirements of the daily order before granting approval to start work. The licensee has identified that improvement is necessary in the mechanism it uses for transmitting new information and requirements to its staff and for ensuring that requirements are properly implemented. The inspectors will evaluate the adequacy of the licensee's corrective action for this issue during a future inspection.

b. WO 940205-EH, Investigate and repair +15V secondary power supply in Unit 2 EH controller.

   This activity is discussed in detail in paragraph 2.b.2.

c. WO 9401417-FW, Noisy Unit 2 feedwater process rack power supply fan.

   Upon identification of the noisy fan, the licensee unplugged the fan on March 8, 1994, and adjusted the feedwater process rack, primary power supply output voltage to less than the output voltage of the secondary power supply. This resulted in the primary power supply becoming the "backup" for the secondary power supply. The licensee elected not to work in the feedwater process rack until a scheduled unit power reduction in order to avoid the risk of causing a feedwater transient. The inspectors observed the licensee replace the fan and re-adjust the primary power supply voltage to normal when Unit 2 was offline on March 27, 1994.

d. 18 month preventive maintenance on No. D5 emergency diesel generator (EDG).

e. 18 month preventive maintenance on No. D1 EDG.

During the post-maintenance test, D1 EDG failed to meet acceptance criteria for attaining proper voltage within 10 seconds of its start signal. The licensee's investigation identified that a fuse clip was bent in the generator excitation circuitry creating an open circuit. The fuse had been removed to support electrical maintenance. After correcting the fuse clip problem, the test was successfully completed.

f. Replacement of motor-operated valve actuators on No. 11, 12, 21, and 22 auxiliary feedwater pump discharge valves.

One violation was identified. No deviations, unresolved items, or inspection followup items were identified.

4. <u>Surveillance (37700, 61726, 71707)</u>

The inspectors reviewed Technical Specification required surveillance testing as described below, and verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, and Limiting Conditions for Operation were met. The inspectors further verified that the removal and restoration of affected components were properly accomplished, test results conformed with Technical Specifications and procedure requirements, test results were reviewed by personnel other than the individual directing the test, and deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Portions of the following test activities were observed or reviewed:

- SP 2035A, "Reactor Protection Logic Test at Power"
- SP 3032A, "Safeguards Logic Test"
- SP 1003, "Unit 1 Analog Protection Functional Test"
- SP 1106A, "12 Diesel Cooling Water Pump Test"
- SP 1106B, "22 Diesel Cooling Water Pump Test"
- SP 1158, "Cooling Water Valves Test"

No violations, deviations, unresolved items, or inspection followup items were identified.

5. <u>Licensee Followup on Previously Identified Items (92701)</u>

a. <u>(Closed) Inspection Followup Item 50-282/91024-01; 50-306/91024-01(DRP)</u>: Safeguards Battery Room Ventilation System

The original plant design included a safety-related system for cooling the Unit 1 and Unit 2 safeguards battery rooms. This system would have contained unit coolers supplied from the quality assurance (QA) level I cooling water system. During the design review process, a concern developed regarding the introduction of a potential source of water leakage into the battery rooms. As a result, the planned safety-related cooling system was eliminated from the original plant design. The plant was constructed with the non-safety-related Turbine Building ventilation system supplying approximately 800 cubic feet per minute (CFM) of air to the safeguards battery rooms via the ventilation system's main supply fans. Return air was discharged to the Turbine Building. In addition, the battery rooms were provided with a special ventilation system for removing accumulated hydrogen released from the battery cells. This system is powered from class 1E power sources and draws about 300 CFM of air from each of the battery rooms.

Due to a concern involving cracking of individual battery cell jars from elevated room temperature, the licensee installed a battery room ventilation and cooling system modification. This modification consisted of fans, dampers, and cooling coils to allow recirculation and cooling of air flowing through the battery rooms. The system was not installed as a QA level 1, safety-related system. All other plant safety-related, electrical equipment rooms have safety-related ventilation and cooling systems. As discussed in NRC Inspection Reports 50-282/91020; 50-306/91020(DRP) and 50-282/91024; 50-306/91024(DRP) the licensee had been unable to verify that the safety-related battery rooms have adequate ventilation during all postulated accidents. The results of licensee analyses indicated that with high initial ambient temperatures, if a loss of the battery room ventilation system occurred, room temperatures could exceed the vendor's recommended maximum allowable temperature of 104 degrees Fahrenheit for continuous operation of the battery chargers. This condition could result from a steam line break in the Turbine Building concurrent with a loss-of-offsite-power (LOOP) event. According to the licensee's analysis, if the fire doors between the battery rooms are opened within one hour of a LOOP event to reduce the ambient temperature increase, room temperatures would reach 124 degrees Fahrenheit after four hours and would reach 134 degrees after 10 hours.

As discussed in NRC Inspection Report 50-282/91024; 50-306/91024(DRP), the licensee documented its equipment operability determination in safety evaluation (SE) 319, "Justification for Continued Operation, Battery Room Heatup on a Loss of Offsite Power". This SE provided justification for continued plant operation while the licensee evaluated the need for more permanent corrective action. The inspectors discussed the status of actions to resolve the battery room heatup issue with the licensee. The licensee stated that the original battery room heatup analysis was based on conservative calculations. The licensee plans to refine the calculations and re-evaluate the underlying assumptions. For example, the high energy line break (HELB) analysis of record treats the 695' and 715' levels of the Turbine Building as one space. Modifying the analysis to more accurately reflect the actual Turbine Building configuration should result in lower battery room wall temperatures. Similarly, more accurate assumptions for heat sources in the auxiliary feedwater pump rooms should reduce battery room wall and ceiling temperatures. The licensee plans on completing the re-analysis by August 1, 1994, and expects the results to indicate that it takes a longer time to exceed 122 degrees upon loss of ventilation. The licensee also intends to replace all four battery chargers; with new chargers installed in one train for each unit by December 31, 1994, and the remaining chargers installed and tested by March 1, 1995. The replacement battery chargers will be rated for 122 degrees ambient temperature.

In the event of a LOOP, non-safeguards diesel generators D3 and D4 automatically start. The licensee has implemented abnormal operating procedures for recovering power to the battery room ventilation system from either the D3 or D4 diesel generators. The licensee estimates that it would take about two hours to restore power using this method. The licensee is developing a more comprehensive preventive maintenance program for these diesels and expects to have the program fully implemented by October 1, 1994.

The inspectors will review the results of the licensee's battery room heatup re-analysis upon completion. The inspectors concluded that the licensee had taken appropriate action to resolve the battery room heatup issue. This item is closed.

b. <u>(Closed) Violation 50-306/92006</u>: Inadequate Procedure for Reactor Coolant System Reduced Inventory

On February 20, 1992, an interruption of decay heat removal during Unit 2 reduced inventory operations occurred. In response to this event, the NRC dispatched an Augmented Inspection Team (AIT) to the site to conduct an investigation (refer to NRC Inspection Report 50-306/92005). The AIT concluded that a combination of factors, including inadequate supervision, level instrument design limitations, reduced engineering support, procedure ambiguities, and inadequate training resulted in the licensee reducing reactor coolant system (RCS) water level below the point required for continued operation of the in-service residual heat removal (RHR) pump, causing the licensee to shut off the pump and interrupt operation of the RHR system. Based on the results of the AIT and a followup inspection by the resident inspectors, the NRC conducted an enforcement conference with the licensee and subsequently issued a Severity Level III violation with civil penalty for the use of an inadequate procedure for reduced RCS inventory operations. A Notice of Deviation was also issued for the installation of RCS level instrumentation that did not meet the licensee's commitments to NRC Generic Letter 88-17, "Loss of Decay Heat Removal" (refer to NRC Inspection Reports 50-306/92006(DRP) and 50-306/92009(DRP)). The subject deviation is discussed in paragraph 5.c.

In response to the event, the licensee developed a corrective action plan containing action items for improvements in the areas of procedures, hardware, management, and training. The action plan expanded upon the licensee's corrective action commitments collectively identified in the associated LER and in the licensee's response to the NRC violation issued for this event. However, the action plan items were not considered NRC commitments. During this inspection and previous NRC inspections (refer to NRC Inspection Reports 50-306/92006(DRP), 50-282/92020; 50-306/92020(DRS), 50-282/92022; 50-306/92022(DRP), 50-282/92024; 50-306/92024(DRP), 50-282/92201; 50-306/92201, and 50-282/92029; 50-306/92029(DRP)), the inspectors reviewed several of the action plan items as well as the corrective actions identified in the licensee's June 15, 1992 violation response. The specific corrective actions and their implementation status are provided as follows:

(1) "All corrective actions that have been completed to date pertaining to procedure inadequacies will be incorporated in future revisions to the procedures as appropriate."

The inspectors verified that procedural inadequacies identified by the NRC and the licensee have been corrected in the RCS draining and reduced inventory operations procedures for both units.

(2) "A self-limiting hot leg drain path will be provided on the Reactor Coolant System, with the piping routed to just below the top of the inside diameter of the hot leg during the draining process."

This modification was installed in Unit 1 and Unit 2 in December 1992 and December 1993, respectively. Some remaining minor Unit 1 work will be completed during the May 1994 refueling outage.

(3) "The location of the tap off of the Reactor Coolant System used for shutdown purification will be changed to the Loop A pressurizer spray line. This location is at the centerline of the cold leg which would limit any potential overdraining while in the shutdown mode. The resulting level, if problems were encountered, is adequate to support residual heat removal pump operation and prevent any significant vortexing. This path also provides remote isolation capabilities from the control room."

This modification was installed in Unit 1 and Unit 2 in December 1992 and December 1993, respectively.

(4) "A communication path between the Loop A hot leg and cold leg will be installed, to be used during the draindown. This line will assure equalization of pressure across Loop A of the Reactor Coolant System. A communication path presently exists for Loop B."

This modification was installed in Unit 1 and Unit 2 in December 1992 and December 1993, respectively. The communication path for Loop B is the pressurizer itself.

(5) "The vent path on the reactor head will be enlarged to assure more timely pressure equalization of the reactor head volume during the draining process."

This modification was installed in both units in December 1992.

(6) "A non-intrusive Reactor Coolant System level indication system will be installed. This new system will be unaffected by the pressure in the Reactor Coolant System, thereby providing continuous level indication during any potential loss of shutdown cooling event. This indication will only monitor level in the diameter of the loop piping and not the total Reactor Coolant System level."

This modification was installed in Unit 2 in December 1993. Unit 1 installation and preoperational testing will be completed during the May 1994 outage.

(7) "Nitrogen will no longer be added to the Reactor Coolant System in the over-pressurization mode; rather, it will be added directly to the steam generators via a drain path in the Reactor Coolant System intermediate loop. With this change it will no longer be necessary to drain to the mid-loop elevation."

This modification was installed in Unit 2 in December 1993. Unit 1 installation and preoperational testing will be completed during the May 1994 outage.

(8) "New procedures for reduced inventory operations with the Reactor Coolant System intact will be developed to support the new hardware."

The inspectors verified that RCS draining procedures and RCS reduced inventory procedures have been developed, supporting the new hardware, for both units. The Unit 2 procedures were tested in December 1993. The Unit 1 procedures will be tested during the May 1994 outage. Portions of the Unit 1 hardware were preoperationally tested in December 1992.

(9) "Section Work Instruction, SWI-O-34, Infrequently Performed Operations,' will be implemented in the development of the new draindown procedures. This SWI provides management input to assure there is the appropriate balance of engineering support, operations management, and training. It further defines the scope of the pre-task briefing and raises the importance of the task to the appropriate management level. This SWI will also be used to review the adequacy of all other critical evolution procedures."

The inspectors verified that the new draindown procedures contain the guidance specified in SWI-O-34. The inspectors observed the licensee use the guidance in SWI-O-34 during its preparations for other infrequently performed operations. For example, SWI-O-34 was used successfully in preparation for maintenance on the Unit 2 nuclear steam supply system annunciator system on January 21, 1994 (refer to NRC Inspection Report 50-282/94002; 50-306/94002(DRP)).

(10) "To the extent practicable, the new procedures will be validated on a simulator, assuring their usability."

The licensee's simulator is not capable of successfully modelling reduced RCS inventory operations. The new procedures were validated during preoperational testing of the hardware. Information from the testing was incorporated into the procedures as appropriate.

(11) "The operations organization will receive thorough training on the new draindown procedures. Other plant groups will receive training to the extent needed for each group."

Each operations department crew has received training on the new procedures and hardware during the routine training center cycle. The inspectors interviewed the senior reactor operator responsible for presenting procedural and hardware information to the operating crews. Additional training will be provided to the operations department crews and appropriate engineering staff prior to the next time that the licensee will enter reduced RCS inventory conditions when there is fuel in the reactor (currently scheduled for the May 1995 Unit 2 refueling outage).

The inspectors concluded that the licensee's corrective actions in the areas of hardware, procedures, management, and training addressed the weaknesses that caused the February 20, 1992, draindown event and appeared adequate to prevent recurrence. The May 1994, Unit 1 refueling outage will require a full core offload in order to support inservice inspection of the RCS. Therefore, reduced RCS inventory conditions to support steam generator nozzle dam installation will be conducted with no fuel in the reactor. This will enable the licensee to perform additional preoperational testing of its procedures and modifications with no additional risk. The inspectors will followup on the licensee's activities with regard to the new draindown modification and procedures during the Unit 1 outage. This item is closed.

c. <u>(Closed) Deviation 50-306/92009-01(DRP)</u>: Redundant and Independent Reactor Coolant System Level Instrumentation

In its response to NRC Generic Letter 88-17, "Loss of Decay Heat Removal," the licensee committed to perform a modification to provide two independent reactor coolant system (RCS) level indications for use during plant outages. The modification installed electronic RCS level instrumentation (pressure transmitters) in each reactor coolant loop for both units. However, independence of the level instrumentation was not attained. A single pressure instrument at the pressurizer relief tank was used to provide RCS overpressure compensation for both RCS electronic level instruments and the locally observable "tygon tube" level instrument. This was a deviation from the licensee's commitments in its response to Generic Letter 88-17 (refer to NRC Inspection Reports 50-306/92005, 50-306/92006(DRP), and 50-306/92009(DRP) which discuss the Unit 2, February 20, 1992, interruption of residual heat removal event).

The licensee implemented several corrective actions in response to the identified deviation. Procedures for reduced inventory operations were revised to require venting of the RCS to the containment atmosphere and to prohibit the use of nitrogen overpressure. Level instrumentation required no pressure compensation when the RCS was in the vented condition. Also, the licensee developed a modification plan for the installation of a diverse, non-intrusive RCS level instrumentation system using ultrasonic transducers strapped to the hot legs of the RCS. Before entering reduced inventory conditions during an outage, the ultrasonic transmitters are installed on each hot leg and wired to provide indication to the control room operators of water level in each RCS hot leg. The inspectors observed portions of the hardware installation for this modification in the Unit 1 and Unit 2 containment buildings during previous outages and observed portions of the preoperational testing of the modification during the last Unit 2 outage. Additional system preoperational testing is scheduled for the upcoming Unit 1 outage in May 1994. The licensee will continue to use electronic and tygon tube level instruments as the principal means for measuring RCS level, however, the ultrasonic level instruments add an additional, diverse means of monitoring level during reduced RCS inventory conditions. This item is closed.

d. <u>(Closed) Violation 50-282/92011-02; 50-306/92011-02(DRP)</u>: Auxiliary Feedwater Pump Surveillance Testing

Technical Specification (TS) 4.8.A.8 requires verification, at least once every 18 months, that each auxiliary feedwater (AFW) pump starts automatically as designed, upon receipt of each AFW system actuation test signal. Each unit has two AFW pumps, one motor-driven and one turbine-driven. There are five AFW system actuation signals: Low-low water level in either of two associated steam generators (starts both AFW pumps), undervoltage on both associated 4 kV busses (starts turbine-driven pump only), trip of both main feedwater pumps (starts both AFW pumps), safety injection (starts both pumps), and anticipated-transient-without-scram mitigation system actuation circuitry (AMSAC) (starts both pumps). The AMSAC actuation signal is not required by Technical Specifications. Prior to June 4, 1992, the licensee had never tested the AFW pumps to verify that each AFW pump would start automatically upon receiving an actuation signal from each associated steam generator low water level circuit or upon receiving an actuation signal from the circuitry that senses that both associated main feedwater pump breakers are open (refer to NRC Inspection Report 50-282/92011; 50-306/92011(DRP)).

As discussed in the referenced NRC Inspection Report, during a review of NRC Information Notice 88-83, "Inadequate Testing of Relay Contacts in Safety-Related Logic Systems", as part of the licensee's operating experience assessment program, licensee engineers noted that the low steam generator level and loss of main feedwater, AFW system actuation signals were not being tested. The licensee initiated action to test these signals, however, the lack of testing was not recognized as an operability concern.

On March 6, 1992, the licensee identified that annual full flow testing of the turbine-driven AFW pumps, as required by TS 4.8.A.2, had not been performed within the allowed surveillance interval. In the licensee event report submitted for this event (50-282/92004), the licensee committed to performing a comprehensive review of TS surveillance requirements to ensure that all required testing was being conducted. As part of this review, the licensee identified various AFW system testing discrepancies, including the fact that TS 4.8.A.8 required AFW system testing was not being fully performed. The Operations Committee (onsite safety review) was informed of the testing deficiencies in a letter dated March 16, 1992, and subsequently raised the question of AFW pump operability during discussions on March 26. The Operations Committee (OC) tasked the staff with determining if a surveillance requirement had indeed been missed. This action item was not documented in the meeting minutes and no priority was assigned to this resolution. After reviewing the identified AFW system testing discrepancies, the inspectors questioned the operability of the AFW pumps for both units. On

June 4, 1992, after further review of TS 4.8.A.8 testing requirements, the OC declared all four AFW pumps inoperable and entered TS Limiting Condition for Operation 3.0.C for both units, which provided one hour to prepare for shutdown and six hours to achieve hot shutdown. The licensee requested and was granted a temporary waiver of compliance to allow 24 hours to complete the required testing. Testing to fulfill the requirements of TS 4.8.A.8 was performed on June 4, 1992, and the pumps were declared operable.

In the response to this violation, dated September 4, 1992, the licensee stated that on March 2, 1981, a TS license amendment which incorporated TS 4.8.A.8, was not fully implemented due to an inadequate review by plant staff. No formal implementation procedure for license amendments existed at that time. Since initial plant licensing, the only AFW system actuation signal tested was the safety injection (SI) signal during the "integrated SI test" conducted each refueling outage. Prior to the March 2, 1981 TS amendment, no other formal testing of AFW pump automatic start signals was required. The violation response also stated that following the identification of AFW system testing discrepancies as part of the comprehensive review of TS surveillance requirements, the OC failed to press for resolution of the AFW pump operability question in a timely manner. The resolution process, which should have been prompt, took three months.

The licensee implemented several corrective actions to prevent recurrence. Surveillance procedures were developed incorporating the testing requirements of TS 4.8.A.8, and these procedures were used to successfully complete the subject testing during the last refueling outage for each unit. The plant manager reviewed the event with licensee staff and with the OC, emphasizing to the OC that when operability issues arise, the OC should assume inoperability until convinced otherwise. The event was discussed during engineering staff training to increase staff awareness of operability issues. The operating experience assessment form has been revised to insure that reviews of items such as information notices include operability considerations. The licensee completed a comprehensive review of TS surveillance requirements to verify that all required testing was being conducted. No additional discrepancies, other than those associated with the AFW system, were identified. In 1984 the licensee established the Technical Specification Change Review Committee, a subcommittee of the OC, to review and properly implement TS license amendments. The licensee is confident that if a TS licensee amendment similar to the March 2, 1981, amendment were presently issued, it would receive an appropriate review and would therefore be properly implemented.

The inspectors verified that the licensee implemented each of the corrective actions committed to in its violation response, and concluded that these actions appeared adequate to prevent recurrence. This item is closed.

e. <u>(Closed) Violation 50-282/92029-02; 50-306/92029-02(DRP)</u>: Failure to Submit Licensee Event Report within 30 Days

On November 29, 1992, the licensee blocked open two fire doors in the control room and did not implement the requirements of Technical Specification 3.14.G.2 by designating an individual to perform hourly fire watch duties. On December 4, 1992, the inspectors informed the licensee that this was a condition prohibited by the Technical Specifications, however, the licensee failed to submit an LER within 30 days as required by 10 CFR 50.73. To prevent recurrence, the plant manager issued a letter to supervisory personnel discussing the necessity to forward reportability decisions to appropriate plant staff so that proper reporting is completed. The inspectors have not identified any other instances of failure to submit a required LER. This item is closed.

f. <u>(Closed) Violation 50-306/93008-01(DRP)</u>: Loss of Administrative Control of a Containment Isolation Valve

On April 13, 1993, air-operated containment isolation valve CV-31342, Reactor Makeup Water to Unit 2 Containment, was inoperable for greater than four hours, but was not deactivated in the closed position by isolating its air supply, or in lieu of that, containment isolation valve 2RM-8-4, Supply to Pressurizer Relief Tank, was not locked closed. This event is discussed in detail in NRC Inspection Report 50-282/93008; 50-306/93008(DRP). As discussed in that inspection report, poor communications between the system engineer, shift supervisor, and control room operators was one of the primary causes of the subject event.

The licensee implemented specific corrective actions to prevent recurrence. An operations department newsletter was issued discussing requirements for oral communications. Operators were tasked with reviewing existing administrative requirements for both oral communications and the use of safety tags to control equipment status. The licensee initiated reviews of the work control process and the safety tag process. Based on these reviews, the licensee revised the work control process to clarify the requirements for initiating troubleshooting work requests. The inspectors concluded that the licensee's corrective action in response to the subject violation appeared adequate to prevent recurrence. This item is closed.

g. <u>(Closed) Inspection Followup Item 50-282/92010-02; 50-306/92010-02(DRP)</u>: Unit 2 Emergency Diesel Generator Fuel Oil Day Tank Capacity

An issue was identified during preoperational testing of the Unit 2 emergency diesel generators (EDGs) regarding the fuel oil capacity of the day tanks. As discussed in NRC Inspection Report 50-282/92010; 50-306/92010(DRP), the design report for the Unit 2 EDGs indicated that each day tank was sized to provide a supply of fuel-oil to its respective EDG for a minimum of 1 hour of operation at full load. This was less than the capacity specified in the updated safety analysis report (USAR) for the Unit 1 EDGs (2 hours of operation at full load). The inspectors discussed this discrepancy with the licensee and reviewed the NRC Standard Review Plan (NUREG-0800), Regulatory Guide 1.137, "Fuel-Oil Systems for Standby Diesel Generators," and ANSI Standard N195-1976, "Fuel Oil Systems for Standby Diesel-Generators," and concluded that the fuel-oil capacity of the Unit 2 EDG day tanks is acceptable. The USAR has been updated to reflect the difference in capacity between the Unit 1 and Unit 2 EDGs. This item is closed.

h. <u>(Closed) Inspection Followup Item 50-282/92010-04; 50-306/92010-04(DRP)</u>: Unit 2 Emergency Diesel Generator Cooling Water Quality

An issue was identified during preoperational testing of the Unit 2 EDGs regarding the cleanliness of cooling water in the high temperature (HT) and low temperature (LT) closed loop cooling water systems for each engine. As discussed in NRC Inspection Report 50-282/92010; 50-306/92010(DRP), many flushes of the cooling water systems were required to remove particulate contaminants. The inspectors discussed this issue with the licensee and reviewed results of HT and LT system water quality monthly inspections. Chemistry analyses have demonstrated that vendor-specified criteria for particulates in the coolant systems have been satisfied. This item is closed.

No violations, deviations, unresolved items, or inspection followup items were identified.

6. <u>Licensee Event Report (LER) Followup (92700, 90712, 92701)</u>

a. <u>(Closed) LER 50-282/91004</u>: Failure of Redundant Heat Trace Circuits as a Result of Electrical Fault

Both trains of heat tracing failed on a section of safety injection system suction piping when an operator stepped on the pipe insulation. The inspectors review of selected corrective actions for this event is documented in NRC Inspection Report 50-282/92029; 50-306/92029(DRP). During this inspection period, the inspectors completed their review of the remaining corrective actions. The licensee is developing a surveillance procedure to periodically test heat tracing for an electrical ground fault per the recommendations contained in IEEE standard 515-1989. This item is closed.

b. <u>(Closed) LERs 50-282/91009-00, 91009-01, 91009-02</u>: Discovery that a Contract Employee was Improperly Granted a Security Clearance

On August 14, 1991, the licensee submitted LER 50-282/91009 to advise the NRC that a licensee contractor had failed to inform the licensee of a contractor employee's past fitness-for-duty (FFD) positive drug tests, and that the employee had not met all access authorization requirements prior to being granted access to the Prairie Island Nuclear Generating Plant. The subject LER stated that the contract employee did not have the required FFD management and medical evaluation and was granted access to the Prairie Island Nuclear Generating Plant from August 30 to September 28, 1990. The LER also indicated that the subject contract employee had been denied access at three other nuclear facilities in 1987 due to positive drug tests.

10 CFR Part 26.23(a)(2) prohibits a person denied access at any nuclear power plant from being assigned to work within the scope of 10 CFR Part 26 without the knowledge and consent of the licensee. 10 CFR Part 26.27(a) requires a management and medical determination of FFD to be performed if an individual granted unescorted access had a prior positive FFD test result. 10 CFR Part 26.27(a) also requires such an evaluation to be completed prior to granting unescorted access.

On July 15, 1991, the licensee concluded that a contractor (Nuclear Support Services, Incorporated) requested access to the Prairie Island Nuclear Generating Plant for an employee who had past positive FFD test results and failed to advise the licensee of this fact. Therefore, the management and medical determination of FFD was not completed prior to the granting of unescorted access. This is a violation of 10 CFR Part 26.

Upon identification of the violation, the licensee initiated an investigation of the incident. The investigation results (referenced in the LER) concluded that the contractor security manager was aware of the individual's past positive FFD test results, but failed to advise the licensee of those test results. The inspectors noted that the licensee implemented comprehensive corrective actions in response to this event and concluded that these actions appeared adequate to prevent recurrence. As described above, the licensee's actions appeared to be in violation of NRC requirements. However, the violation is not being cited because the criteria specified in Section VII.B.2 of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C), were satisfied. Subsequent enforcement action has been taken against the contractor security manager and the contractor firm (Nuclear Support Services, Incorporated). Refer to paragraph 7 for a synopsis of the results of the contractor investigation performed by the NRC Office of Investigations. This item is closed.

c. (Closed) LER 50-306/92001: Unplanned Auto-start of an Auxiliary Feedwater Pump due to Personnel Error

On February 19, 1992, during the performance of surveillance procedure (SP) 2103, "No. 22 Turbine-Driven Auxiliary Feedwater Pump Test", No. 21 motor-driven auxiliary feedwater pump (AFW) started automatically on low steam generator water level (refer to NRC Inspection Report 50-282/92004; 50-306/92004(DRP)). At the time of the test, Unit 2 was in hot shutdown in preparation for refueling. Some amount of steam leakage past the closed main steam isolation valves was causing limited cooldown of the reactor coolant system (RCS). The addition of feedwater to the steam generators during the performance of SP 2103, which is a full flow test of No. 22 AFW pump, resulted in additional RCS cooldown and shrinkage of the steam generator levels. The operator performing the test in the control room was cautioned by other operators to watch steam generator level. The operator noted that wide range level was at 65 percent, and did not realize that the other operators were alerting him to the potential automatic start of No. 21 motor-driven AFW pump at 13 percent narrow range level. The other operators did not specify which steam generator level indications to watch or why level was a concern.

The licensee implemented specific corrective actions to prevent recurrence. Involved personnel were reminded that verbal messages need to be clear and complete to avoid misunderstandings. Auxiliary feedwater pump test procedures were revised to follow the writers' guide for procedural content. The licensee also reviewed the conditions for performing SP 1103 (Unit 1) and SP 2103 to determine the optimum time for conducting the AFW pump full flow test. In the past this test had been performed at hot shutdown. The licensee concluded that the test could be performed safely at power based on an analysis of feedwater nozzle thermal cycling. The licensee revised SP 1103 and SP 2103 to allow performance of the test between 40 and 98 percent power.

The inspectors verified that the licensee implemented each of the corrective actions committed to in the LER submitted for this event, and concluded that these actions appeared adequate to prevent recurrence. This item is closed.

d. (Closed) LERs 50-306/92002-00 and 92002-01: Interruption of One Train of Residual Heat Removal During a Unit 2 Reactor Coolant System Draining Operation

The inspectors have reviewed the majority of the licensee's corrective actions for this event, as described in the associated LER, during previous inspections (refer to NRC Inspection Reports 50-306/92006(DRP) and 50-282/92029; 50-306/92029(DRP)). The subject LER also referred to an action plan that was developed to organize and implement improvements in procedures, hardware, management, and training for RCS draining operations and other critical evolutions. This action plan is further discussed in paragraph 5.b. This item is closed.

e. <u>(Closed) LER 50-306/92004</u>: Auto-start of D5 Diesel Generator Due to Personnel Error.

This event is discussed in detail in NRC Inspection Report 50-282/92024; 50-306/92024(DRP). The LER submitted by the licensee for this event was a voluntary report since the D5 emergency diesel generator (EDG) was not technically an "operable" engineered safety feature, as its installation and turnover to plant operations was not complete at the time of the event.

The licensee's corrective action to prevent recurrence included an immediate safeguards rack work stoppage to discuss the event with workers and supervisors, conducting training for electricians on the importance of clear communications when completing procedural steps, modification of the Emergency Response Computer System to improve operator identification of EDG alarms, and completion of control room annunciator panel modifications. The inspectors concluded that the licensee's corrective action appeared adequate to prevent recurrence. This item is closed.

f. <u>(Closed) LER 50-282/92015</u>: Auto-start of both Diesel Cooling Water Pumps due to Error in Modification Procedure

On November 5, 1992, modification work was being performed on the Unit 1 control room F panel. Instrumentation was being removed from the old F panel in preparation for installation of a new panel. Leads were being disconnected from the circulating/cooling water intake bay level indicator circuit. Disconnection of one of two leads resulted in a low intake bay level indication and subsequent trip of No. 11 motor-driven cooling water pump. This caused both diesel-driven cooling water pumps to automatically start on low cooling water header pressure (refer to NRC Inspection Report 50-282/92029; 50-306/92029(DRP)). The event was apparently caused by inadequate preparation and review of the work package for removing the level indicator from the control room F panel. The licensee's corrective action for this event was to emphasize to all engineering and technical staff personnel the need for completeness and accuracy in the generation of modification installation work packages.

Since this event, the licensee has implemented several modifications. The inspectors have observed selected modification activities and have reviewed the associated work packages. The inspectors noted that the packages were detailed and complete and did not identify any instances where it appeared that the work package had been inadequately reviewed. The inspectors concluded that the licensee's corrective action appeared adequate to prevent recurrence. This item is closed.

g. (Closed) LER 50-282/93001: Failure to Perform Hydrogen Recombiner Testing in the Sequence Specified by the Technical Specifications

This event is discussed in detail in NRC Inspection Report 50-282/92029; 50-306/92029(DRP). To prevent recurrence, the licensee revised the hydrogen recombiner test procedure to specify the testing sequence required by Technical Specifications (TS). The licensee performed the functional test and the resistance to ground check for both Unit 1 and Unit 2 hydrogen recombiners in the sequence specified by the TS during the Fall 1992 dual-unit outage. The inspectors concluded that the licensee's corrective action appeared adequate to prevent recurrence. This item is closed.

h. (Closed) LER 50-282/93006: Automatic Start of No. 121 Cooling Water Pump on Low Header Pressure While Aligned for Safeguards Operation

On March 25, 1993, No. 121 motor-driven cooling water (CL) pump started automatically on low header pressure while aligned for safeguards operation. The licensee was conducting a surveillance test to satisfy post-maintenance testing requirements for No. 22 diesel-driven CL pump. This event is discussed in detail in NRC Inspection Report 50-282/93002; 50-306/93002(DRP).

On March 1, 1994, No. 121 CL pump started automatically on low header pressure while aligned for safeguards operation. The licensee was conducting post-maintenance testing of No. 12 diesel-driven CL pump following repair of a lube oil leak. This event is discussed in detail in NRC Inspection Report 50-282/94002; 50-306/94002(DRP).

The licensee's corrective action to prevent recurrence for the March 25, 1993, event was to discuss the event with those individuals involved in the weekly work planning meeting, and to revise both the routine surveillance and annual preventive maintenance procedures for the diesel-driven CL pumps to clarify the instructions for disposition of the pump discharge header, motor-operated isolation valves MV-32034, MV-32035, MV-32036, and MV-32037. The licensee did not consider revising operating procedure C35, "Cooling Water System", to address the positioning of the common discharge header isolation valves when securing the operating diesel-driven CL pump with the associated motor-driven CL pump running and No. 121 CL pump aligned for safeguards operation.

Regarding the March 1, 1994 event, the post-maintenance testing requirements specified in the work request initiated to repair a leaking elbow in the lube oil system for No. 12 CL pump, verified the integrity of the lube oil system piping. The work request did not contain any direction to perform the routine surveillance test to demonstrate pump operability. The licensee verified that the lube oil leak had been repaired by running the pump using the normal system operating procedure, C35.

The inspectors concluded that the licensee's corrective actions to prevent recurrence of the March 25, 1993 event were inadequate as demonstrated by the March 1, 1994 event. The inspectors also concluded that the CL system operating procedure, C35, was inadequate in that it did not address the potential for an automatic start of No. 121 CL pump. Criterion V of Appendix B to 10 CFR Part 50, requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Operation and post-maintenance testing of No. 12 CL pump, an engineered safety features (ESF) component, is an activity affecting quality. Operating procedure C35 was not appropriate to the circumstances of its use in that it did not address the potential for an automatic start of No. 121 CL pump when securing the operating diesel-driven CL pump with the associated motor-driven CL pump running and No. 121 CL pump aligned for safeguards operation. This is a violation of Appendix B Criterion V (50-282/94003-02; 50-306/94003-02(DRP)). No response to this violation is required since the licensee's corrective actions to prevent recurrence are documented in LER 50-282/94001, submitted for the March 1, 1994 event (refer to paragraph 6.i). This item is closed.

i. <u>(Closed) LER 50-282/94001</u>: Automatic Start of No. 121 Cooling Water Pump on Low Header Pressure While Aligned for Safeguards Operation

This event is discussed in paragraph 6.h. The licensee's corrective action to prevent recurrence for this event, as described in the LER, was to revise the CL system operating procedure, C35, and to consider the feasibility of incorporating a time delay in the start circuitry for No. 121 CL pump. The inspectors verified that C35 had been revised and discussed the issue of ESF actuations of No. 121 CL pump on low header pressure with the CL system engineer. The inspectors concluded that the licensee's corrective action appeared adequate to prevent recurrence. Refer to paragraph 2.b.1 for further discussion of automatic starts of No. 121 CL pump. Both violation 50-282/94003-02; 50-306/94003-02(DRP) and this LER are closed.

j. <u>(Closed) LER 50-282/94002</u>: Inoperability of Radwaste Building Radiation Monitor R-35 went Undetected because of Component Failure

On February 7, 1994, the Radwaste Building ventilation system radiation monitor, R-35, was removed from service for modification of its associated sampling system. On February 11, 1994, R-35 was returned to service after modification activities were complete.

On March 3, 1994, the noble gas detector in R-35 did not respond when source-checked during the monthly surveillance test. The licensee declared R-35 inoperable and secured the Radwaste Building ventilation system. During the subsequent investigation of the monitor's failure, the licensee discovered a broken detector signal lead. The licensee determined that the lead had been broken during modification activities in February, and concluded that R-35 had been inoperable since that time. The licensee replaced the detector, tested the monitor, and returned it to service on March 9, 1994.

Following the completion of the modification to R-35's sampling system, the licensee restored power to the monitor and noted that it appeared to be functioning properly. The broken detector signal lead should have caused a downscale failure of the monitor's indicating meter. However, the downscale failure feature did not work due to a degraded capacitor in the monitor's electronic circuitry.

Technical Specification (TS) 3.9.F., in referencing TS Table 3.9-2, identifies which radioactive gaseous effluent monitoring instrumentation shall be operable, and provides specific actions if less than the minimum number of required instrumentation channels are operable. In accordance with TS Table 3.9-2, if the R-35 noble gas monitor is inoperable, effluent releases via the Radwaste Building ventilation system may continue for up to 30 days provided grab samples are taken at least once per 8 hours and analyzed for gross activity within 24 hours. The inspectors discussed this event with both the licensee and an NRC Region III radiation protection specialist. Based on these discussions, the inspectors concluded that the inoperability of the R-35 noble gas monitor from approximately February 11 to March 9, 1994, while the Radwaste Building ventilation system was in service with no grab samples being taken, constituted a violation of TS 3.9.F.

Upon discovery of the inoperable R-35 radiation monitor, the licensee repaired the broken detector signal lead, replaced the degraded capacitor, and source-checked the monitor prior to returning it to service. The licensee also verified that the downscale failure feature worked properly on other similar radiation monitors and added a check of this feature to the associated annual calibration procedure. In the LER submitted for this event, the licensee stated that the source-check for R-35 is performed with an external source rather than the installed source, since the installed source is not useful for operability testing. Thus, from an as-low-as-reasonably-achievable standpoint, the licensee concluded that it is not prudent to source-check R-35 after each maintenance activity. The licensee stated that R-35 would be source-checked only if the detector were replaced, or if other work involving the detector or its cabling, were performed. The inspectors concluded that the licensee's corrective action appeared adequate to prevent recurrence.

Based on a review of weekly grab sample results and historical monitoring data, the licensee determined that no releases via the Radwaste Building ventilation system occurred while R-35 was inoperable. The inspectors concluded that this event had minor safety significance. As described above, the licensee's actions appeared to be in violation of NRC requirements. However, the violation is not being cited because the criteria specified in Section VII.B.2 of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C), were satisfied. This item is closed.

k. <u>(Closed) LER 50-282/93005</u>: Unit 1 Reactor Trip Due to Inadvertent Relay Operation which Caused Loss of No. 11 Reactor Coolant Pump

On February 18, 1993, while cleaning floors in the turbine building with a floor burnishing machine, a plant services attendant inadvertently bumped the non-safeguards 4kV bus No. 12, which provides power to the No. 12 reactor coolant pump. The power supply breaker to bus No. 12 opened, creating a bus undervoltage condition and reactor trip on low reactor coolant system flow.

The licensee's corrective actions for this event included installing physical barriers and exclusion areas around selected electrical equipment and limiting the use of power cleaning equipment near sensitive electrical equipment. The inspectors concluded that the licensee's corrective actions appeared adequate to prevent recurrence. This item is closed.

One cited violation and two non-cited violations were identified. No deviations, unresolved items, or inspection followup items were identified.

7. <u>NRC Office of Investigations (OI) Followup</u>

On November 14, 1991, the Regional Administrator, U.S. Nuclear Regulatory Commission, Region III (RIII), requested that an investigation be initiated concerning an allegation that Nuclear Support Services, Incorporated (NSSI) deliberately falsified documents sent to Northern States Power Company (NSP) and Wisconsin Electric Power Company (WEPC) corporate security representatives to allow NSSI employees to gain unescorted access to the NSP Prairie Island Nuclear Generating Plant (Prairie Island) and WEPC Point Beach Nuclear plant (Point Beach). It was also requested that an investigation be conducted to determine if the alleged record falsification was the result of one person's independent action or the result of NSSI's management policies or practices. Additionally, the investigation was also to determine if management of any of the involved parties was culpable in the transfer of false information.

The investigation revealed that the NSSI security manager deliberately provided falsified documents to NSP and to WEPC to allow NSSI employees to gain unescorted access to the NSP Prairie Island and WEPC Point Beach Nuclear plants. The investigation revealed that this was the result of one person's independent action and not the result of NSSI's management policies or practices. The investigation determined that no management of any of the involved parties was culpable in the transfer of false information. During the investigation, however, an allegation surfaced that the manager of security for NSSI deliberately made material false statements to an OI, RIII, investigator. The evidence developed during the OI investigation substantiated that the manager of security deliberately made material false statements to the NRC OI investigator. The NRC subsequently initiated enforcement action against NSSI and the involved NSSI security manager (addressed in separate NRC correspondence).

8. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on April 20, 1994. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.