U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-282/90004(DRP); 50-306/90004(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: February 28 through April 9, 1990

Inspectors: P. L. Hartmann

T. J. O'Connor

Approved By: B. L. Burgess, Chief
Reactor Projects Section 2A

4/20/90
Date

Inspection Summary

Inspection on February 28 through April 9, 1990 (Reports No. 50-282/90004(DRP); 50-306/90004(DRP))

Areas Inspected: Routine unannounced inspection by resident inspectors of plant operational safety, maintenance, surveillance, radiological protection and industrial safety.

Results: Unit 1 has operated continuously at 100% during this inspection period except feedwater perturbation testing on March 20, 1990, and load following on March 31, 1990. Unit 1 has reached 45 days of continuous operation at the end of the report period.

Unit 2's operating performance was marred by reactor trips on March 8, March 9, and March 16, 1990. These reactor trips have been attributed to equipment failure and personnel error and are explained in detail in paragraph 4 of this report. Unit 2 was taken off line on April 6, 1990 to repair leaking tubes in the 21A Feedwater Heater and clean condenser tubes. Unit 2 was returned to power operation late on April 8, 1990.

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Of the 7 areas inspected, one violation of NRC requirements was identified. During the January/February refueling outage, openings in the Auxiliary Building Special Ventilation Zone were not under administrative control as required by Technical Specification 3.6.E.2. The root cause was personnel error.

DETAILS

1. Persons Contacted

E. Watzl, Plant Manager
#D. Mendele, General Superintendent, Engineering and Radiation Protection
#M. Sellman, General Superintendent, Operations
G. Lenertz, General Superintendent, Maintenance
A. Smith, General Superintendent, Planning and Services
R. Lindsey, Assistant to the Plant Manager
#D. Schuelke, Superintendent, Radiation Protection
G. Miller, Superintendent, Operations Engineering
#K. Beadell, Superintendent, Technical Engineering
S. Schaefer, Superintendent, Technical Engineering
M. Klee, Superintendent, Quality Engineering
R. Conklin, Supervisor, Security and Services
G. Eckholt, Nuclear Support Services
#J. Leveille, Nuclear Support Services
A. Hunstad, Staff Engineer
#P. Wildenborg, Health Physicist

Denotes those present at the exit interview of April 12, 1990.

2. Licensee Action on Previous Inspection Findings (92701)

a. (Closed) Unresolved Item 282/90002-02(DRP): Auxiliary Building Special Ventilation Zone Integrity (ABSVZ)

Inspection Report Nos. 282/90002 and 306/90002 identified an inspector concern over an opening created by removal of a blank flange, and subsequent installation of the eddy current cable connection flange. This modified flange is placed on the containment vessel pressurization line to allow passage of eddy current cabling from the auxiliary building to the containment.

Review of the documentation supplied by the licensee confirms that while the eddy current cable connection flange was secured in place, containment integrity was not affected and that an opening in the ABSVZ did not exist. The installation and removal of the eddy current cable connection flange creates an opening in the ABSVZ. The opening created in the ABSVZ during the installation or removal of the eddy current cable connection flange was not under administrative control.

Technical Specification (TS) (Containment Systems) 3.6.E.2 states that openings in the ABSVZ are permitted provided they are under direct administrative control and can be reduced to less than ten square feet within six minutes following an accident. Operations Manual Procedure D54, Control of Openings in the ABSVZ Boundary,

Revision 4, implements TS 3.6.E.2. Step 4.1 states that a log (PINGP 751) shall be kept in the Control Room specifying the size and location of all openings in the ABSVZ. The log shall include the time and date that openings are made and when they are closed. Contrary to the requirements of TS 3.6.E.2 and Operations Manual Procedure D54, between the dates of January 17, 1990 and February 15, 1990, the installation and removal of the eddy current cable connection flange created an opening in the ABSVZ which was not administratively controlled in that the opening was not logged to indicate the size, location, time, and date that the opening was made or closed. This is identified as Violation 282/90004-01(DRP), and administratively closes Unresolved Item 282/90002-02(DRP).

It should be noted that Violation 50-306/89017-01(DRP) was issued on June 20, 1989, which also documented the licensee's failure to administratively control openings in the ABSVZ boundary during outage related activities. Although both violations may be attributed to a lack of sensitivity to openings in the ABSVZ by operations personnel, an additional cause for this violation may be attributed to the work package which directed the installation of the eddy current cable connection flange.

3. Operational Safety Verification (71707, 93702, 82301)

a. Routine Inspection

The inspector observed control room operations, reviewed applicable logs, conducted discussions with control room operators and observed shift turnovers. The inspector verified operability of selected emergency systems, reviewed equipment control records, and 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 the equipment in need of maintenance.

b. Lockdown Search of New Administration Building

On April 4, 1990, the inspectors monitored the activities of the security guards as they conducted the lockdown search of the new administration building. This search was conducted prior to its introduction into the protected area and looked for prohibited materials such as firearms, explosives and drugs. The security guards were assisted by local law enforcement officials and their dogs, one trained for explosives, and the other trained for drugs. No prohibited materials were discovered.

c. Emergency Plan Drill

On March 28, 1990, the resident inspector observed an emergency plan drill. The drill scenario and plant response were observed from

simulator's control room located in the training center. The inspector was satisfied with all activities conducted during the course of the drill scenario. The inspector also attended the critique of the licensed operators conducted by control room controllers. The inspector was satisfied with the objectivity of the critique and the feedback received by the General Superintendent of Operations and the Superintendent of Radiation Protection.

4. Review of Reactor Trips (93702)

During the inspection period three reactor trips occurred on Unit 2. The cause/sequence of events were not immediately related to the December 21 and 26 trips on Unit 2. Each trip is discussed in detail below.

a. March 8, 1990 Turbine Generator Lockout Trip

On March 8, 1990, while at 100% power, the reactor tripped. The cause was a false main generator lockout which causes an immediate reactor trip. All systems functioned as designed (except as noted below) for a secondary side initiated reactor trip, where a 30 second time delay for opening of generator output breaker is not available. This 30 second time delay is designed to supplement/remove the decay heat following a reactor trip.

With the additional heat load to dissipate, several feedwater heaters and moisture separator reheater (MSR) reliefs lifted, releasing steam outside the turbine building until reseating occurred. The relief valve on the suction of the 21 Feedwater Pump lifted and did not reseat, requiring system isolation and subsequent repair. Water hammer occurred in the 14 inch 24A Feedwater Heater to 21 Heater Drain Tank line during the cooldown and depressurization of the secondary side. Back leakage through a check valve was the suspected cause of the water hammer. Check valves in the piping leading to the 24 and 25 Feedwater Heaters and to the Heater Drain Tank were examined and tested for operability. All check valves operated satisfactorily. A gasket leak on the heater drain tank pump discharge valve 212HD1-1 occurred and was fermented. The licensee inspected the secondary systems affected and found no major damage.

The cause of the turbine trip at 100% power was a generator lockout signal generated at the generator bus duct cooling control panel. The lockout signal was generated when an operations instructor depressed the panel test push button. Depressing the test push button energizes the K3 relay (the attached schematic diagram). When the K3 relay is energized, a "b" (normally closed) contact (K3-23) in the "generator lockout power supply" should open, thereby preventing the generator lockout relay (23X-2) from being energized. Additionally, during actuation of the test circuitry an "a" (normally open) contact on K3 closes which provides power to the K2-1 and K2-2 relays. When relays K2-1 and K2-2 are energized, "a" contacts K2-1 (23) and K2-2 (23) close, and would energize relays 23X-2 and 23X-1,

if contact K3-23 were closed. Energization of relay 23X-2 would cause a generator lockout (setpoint 85 degrees C sensed in the bus duct). Energization of relay 23X-1 would cause the autostart of a second bus duct cooling fan to occur (setpoint 60 degrees C sensed in the bus duct).

When the test button was depressed all functions occurred as designed except the K2-23 "b" contact remained closed. Once K2-2 was energized (by K3), the K2-2 (23) contact closed and energized the 23X-2 relay, causing the generator lockout.

The root cause of this equipment failure appears to be age. The equipment was installed during initial plant construction. In response, the licensee has electrically disarmed the test push button on Unit 2. The Unit 1 test button is SECURE CARD tagged against usage. The test push button performs no valuable function other than illumination of test lights which indicate the K2-1 and K2-2 relays are energized. The setpoints for the 23X-1 (second) bus duct cooler fan autostart and the 23X-2 (generator lockout) which are based on bus duct temperature, receive calibration during every refueling outage.

The plant started up at 1027 hours on March 8, 1990, following an Operations Committee review which the backup senior resident inspector attended. The reactor was critical at 2208 hours. Heatup and power escalation ensued. The inspectors will followup licensee review and corrective actions by the Licensee Event Report (LER) 306/90001-LL.

b. <u>March 9, 1990 Reactor Protection Logic NBFD Relay Failure and Subsequent Loss of the "B" Channel of the Reactor Protection System Reactor Trip</u>

The main generator turbine was test tripped at 0128 hours on March 9, 1990. Following this test, the reactor was at about 6% reactor power when preparations were being made to place the turbine online for full power operation. When the turbine was placed on line a reactor trip occurred.

All systems functioned as designed; however, some anomalies occurred which are discussed further below. The cause of the trip was loss of DC power to a portion of the "B" channel of the reactor protection system (RPS) by a fuse (F3) opening. This loss of power removed power to a portion of the "B" reactor protection system, and resulted in the "B" reactor trip breaker opening. The "A" reactor trip breaker tripped shortly thereafter on a high rate flux in the power range nuclear instrumentation which sensed all rods being inserted.

The F3 fuse opening in the "B" train of RPS was caused by the failure of the 2SV2XB NBFD relay, which failed as a short circuit.

This failure resulted in a high current drawn through the relay and opening the F3 fuse. Loss of F3 de-energized the 12 B channel reactor trip relays, and associated permissive circuits and other activation functions. With the de-energization of the reactor trip relays, the "B" channel of RPS logic caused the undervoltage (uv) coil to de-energize and the shunt coil to energize for the "B" reactor trip breaker. Either the uv or shunt coil function will cause the breaker to open.

Three "first out" annunciators illuminated solid on the first out control room annunciator panel. This panel is designed to indicate any activated reactor trip function by a solid annunciator window illumination, and the "first out" trip signal indicated by a flashing annunciator window illumination. The flashing "first out" trip annunciator aids the operator in determining the cause of the reactor trip, which is later verified with the sequence of event computer printout. On the March 9 trip, three first out annunciators illuminated in a flashing mode, indicating they were the "first out."

These alarms were: 1 loop low flow or RCP (Reactor Coolant Pump) breaker open reactor trip; 2 loop low flow or RCP breaker open reactor trip; and RCP buses undervoltage. Following the trip, operators immediately verified power was in fact available to the RCPs and RCP operation was not impaired or suspended. The reason these three annunciators indicated flashing was due solely to the loss of DC power from fuse F3 opening. Three other annunciators on this panel indicated solid. These indicators were the: high flux rate reactor trip; the turbine trip/reactor trip; and the source range high flux rate trip.

The source range detectors were energized when fuse F3 opened. This occurrence is not desirable due to the high flux present the short time prior to rod insertion. The design of the RPS system is conservative in that the loss of both source range detector relays (SRB1XB, SRB2XB) caused the source range detector to energize when fuse F3 opened. With this source range in operation at relatively high power, the source range logic tripped the "A" RPS train logic. This reactor trip signal, however, did not cause the "A" Rx trip breaker to open since this trip was blocked. The design auto-unblock does not occur until 10 EE-10 amperes on both intermediate range nuclear instruments. The source ranger detectors operated with normal indication.

The turbine trip/reactor trip resulted from the initiation of a partly operational logic train. When the "B" Rx trip breaker opened, the P4 permissive was met to pass a turbine trip signal, which occurred as designed. Permissive P-9 will cause a reactor trip signal to be processed if reactor power is greater than 10%. During this event reactor power was less than 10%. P-9, however, was

satisfied when fuse F-3 opened causing both P-9 relays to de-energize (P9-1, P9-2) on the B train of RPS. With P-9 satisfied, a reactor trip signal was processed.

The high negative flux rate reactor trip was a valid signal sensed by the A train of RPS. The rods fell into the core when the "B" Rx trip breaker opened. The large negative change in flux caused this trip to occur in the A channel of RPS and opened the "A" Rx trip breaker.

Additionally, the turbine driven auxiliary feedwater pump autostarted. This was due to the 2TD-AFD relay being de-energized by fuse F3 opening. The 22 TDAFW pump typically autostarts on a reactor trip due to the low SG levels present because of the "shrink" phenomenon. The operators stopped 22 AFW pump at 0236 by placing the control switch in manual, effectively removing the constant autostart signal present.

Replacement of the failed 2SV2XB NBFD relay and fuse F3 were completed on March 10, 1990 at 1405 hours. Reactor protection logic test was then commenced. During this testing, visual inspection of the protection relays identified two relays (P7-1XA, P7-2XB) which were de-energized when they were required to be energized. These relays were P-7 relays, one in each train of RPS.

The failure of these two relays had no immediate effect on the RPS logic. This is due to the parallel design of the P-7 permissive relays. For P-7 to actuate, both relays in a train must de-energize. The failure of one relay per train would not cause nor prevent the intended function. With a relay failed in each train, the P-7 permissive was relying on one relay to bypass the reactor trip functions associated with P-7. The P-7 permissive blocks the following reactor trips with less than 10% power range indication: low pressurizer pressure, high pressurizer level, loss of 1 RCP (low flow or breaker open) and undervoltage on RCP bus. These relays were replaced and RPS logic was retested satisfactorily.

The operations committee reviewed the cause of the reactor trip, planned repair work and retesting of the RPS system. An additional OC meeting was conducted telephonically to review restart after the replacement and testing of the failed P-7 relays. The plant was restarted at 0133 hours on March 10, 1990 with criticality achieved at 0215 hours. Plant heatup and power escalation occurred without incident. The inspectors will follow licensee review and corrective actions documented in LER 306/90002-LL.

c. Unit 2 Rx trip due to loss of Rod Control Reference Voltage

On March 16, 1990, the Unit 2 reactor tripped from 100% power. The cause of the trip was loss of Rod Control Reference Voltage, which ultimately allowed two shutdown bank rods (E-03 and I-11) to fall

into the core. The insertion of the two shutdown bank rods caused a high flux rate (negative) reactor trip. All systems functioned as designed. The senior resident inspector was in the control room at the time of the trip and observed the response to the event.

In response to rod control electronic function problems which resulted in previous reactor trips (December 21, 1989, December 27, 1989, see report 282/89032; 306/89032) electronic monitoring on the E-03 and I-11 rods was initiated and maintained. Due to electronic noise on one channel of a multichannel recorder, an I&C technician with approval of the shift supervisor initiated a troubleshooting activity to identify or eliminate the noise. The I&C technician discussed the possibility that an urgent failure alarm may occur. This warning was based on the changeout of instrument leads for the multichannel recorder, one point being Reference Voltage (V ref). V ref is compared to voltage sensed at sampling resistors for each rod. When V ref went to zero, the demand for stationary coil voltage is zero. With the demand to the moveable coils also being zero (no demand for rod motion), a power cabinet urgent failure alarm occurs.

To measure V ref with the multichannel recorder, the unit is connected electrically as parallel circuit. Removing the multichannel recorder could cause a temporary perturbation in V ref and could cause an urgent failure alarm. The I&C technician discussed this possibility with the Lead Reactor Operator (RO) prior to changing out the instrument leads.

The I&C technician proceeded to change test leads and in an effort to gain information regarding the noise, connected an oscilloscope to the affected test channel. When the oscilloscope was connected, the oscilloscope drew current away from the V ref circuit. The effect was to cause V ref to drop to near zero volts, causing voltage to stationary rod coils to drop to zero. Because the stationary coil voltage and moveable coil voltage was zero, an urgent failure occurred for power cabinet 1AC. When the urgent failure occurred a hold current is applied to the moveable and stationary coils to prevent a rod drop from this logic failure. In this event, rods E-03 and I-11 began movement with the loss of V ref. The hold current supplied by the urgent failure stopped rod movement and prevented the two rods from falling into the core. Total rod motion for the affected rods was about ten steps. The hold current is maintained until the urgent failure is reset. The RO saw the urgent failure, and in accordance with system training, attempted to reset the urgent failure since he understood the cause of the alarm to be temporary and the alarm condition had cleared. When the reset button was depressed, the hold current was removed which allowed rods E-03 and I-11 to fall into the core. Reset removes voltage to moveable coils only. During the event however, the normal voltage that would remain applied to the stationary coils was not available due to the oscilloscope connection. The insertion of two full length rods caused a high flux rate

(negative) reactor trip. The root cause has several contributing factors. The most substantial being use of an oscilloscope which caused V ref to drop to near zero.

The I&C technician had decided to use a Hewlett Packard (HP) Model (54502A) oscilloscope which was leased by NSP for use and evaluation. Calibration documentation was supplied by the leasor to NSP. When the I&C technician brought the HP oscilloscope into the rod control room, he placed the instrument adjacent to the Tektronix oscilloscope Model (564B) which had been left in the rod control room for monitoring activities.

In order to utilize the HP oscilloscope, the I&C technician needed to attach an instrument probe to an input jack on the front panel of the oscilloscope. The I&C technician removed the probe from the Tektronix oscilloscope and connected it to the HP oscilloscope, and went on to connect the oscilloscope to the multichannel recorder.

By using the Tektronix probe, a low input impedance circuit (the HP oscilloscope) was connected in parallel to rod control. The result was the HP oscilloscope drawing most of the current away from rod control and lowering V ref to near zero. The licensee verified by test this action as the cause of the event. The Tektronix oscilloscope had internal circuitry which provided 1 meg ohm (1,000,000 ohms) resistance which would have prevented the oscilloscope from loading the rod control system. The HP oscilloscope has a 50 ohm input impedance. The HP probe (which was in a pouch attached to the oscilloscope) provided (externally) an impedance of 1 meg ohm. The labeling next to the HP probe input jack stated the input impedance as "50 or 1 meg ohm." The technician was not aware that the HP oscilloscope would have only a 50 ohm input impedance with a zero resistance probe.

The second contributing root cause was resetting the urgent failure alarms when rod control system conditions did not warrant reset. This was from multiple causes, inadequate communication and past licensed operator training. The inadequate communication occurred when the I&C technician did not accurately communicate to the RO the extent of his activities with rod control. The RO believed that the activity was extremely short in duration, i.e. only the time to change out the test leads on the multichart recorder. Although the I&C technician was only accessing test points in rod control with the oscilloscope, his activity lasted for a longer duration than what was communicated to the RO. This information was the basis of the RO decision to reset the urgent failure.

The RO action was also based on operator training to reset the urgent failure when the cause was known and had cleared. When the urgent failure annunciator alarmed, the RO believed the cause to be temporary, based on the information supplied to him by the I&C technician. Following a short waiting period, he attempted to reset

the urgent failure. When the reset button was depressed, the hold voltage was removed from the moveable coils and the two rods fell into the core.

The licensee has initiated multiple corrective actions. A temporary change (TM-90-36) has immediately issued to clarify operator actions in regard to resetting urgent failure alarms. Now operations must notify the I&C department prior to resetting the urgent failure alarm (except during rod control exercise tests). A change to the section work instruction (SWI) test instrument calibration control is planned to further control usage of test equipment. In the past, this requirement was informal. The licensee also intends to clarify work control requirements of instrument monitoring. This is to ensure that troubleshooting of test equipment connected to test points is adequately controlled.

The licensee also initiated a procedure change to address an instrument suitability review specifically for adequate input impedance. This action was initiated from the March 16, 1990, reactor trip and a separate instrument loading event which occurred on March 19, 1990. The March 19th event occurred during Unit 1 troubleshooting of rod speed/response time to a reactor coolant temperature error (T error). When a newly acquired strip chart recorder was connected to an isolated channel of turbine impulse steam pressure, the rods began to automatically step into the core.

The I&C technician promptly removed the recorder from the circuit and rod motion stopped. The recorder has two alternative input impedances 1 or 5 meg ohms. The 1 meg ohm input impedance was first used. Following further review and analyses the recorder was connected with 5 meg ohm input resistance. There was no effect on T error. The review disclosed the particular circuit was sensitive to instrument loading. The licensee believes the instrument review for input impedance applicability will address this event and the potential for other similar occurrences. The licensee's efforts in this area are important since the technology of I&C measuring and test equipment continues to improve, and as original equipment ages, more measuring and test equipment will be purchased and utilized by the licensee. The inspectors will follow the licensee's review and corrective actions (LER 306/90003-LL).

5. 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, quality control records were maintained, activities were accomplished by qualified personnel, radiological controls were implemented, and fire prevention controls were implemented.

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

Repair to Traveling Water Screens
Replacement of Reactor Protection Logic Relay 2SV2XB
Replacement of Reactor Protection Logic Relays P7-1XA and P7-2XB
Replacement of Reactor Protection Logic Relay 1RT2-XB
Replacement of the 22 Cooling Water Pump seals, bearings and the pump alignment
Replacement of the 11 Charging Pump Desurger
Trouble shooting of the 11 Fan Coil Unit Breaker
Rebuild of a safety relief valve for the Chemical and Volume Control System
Replacement of Gaskets on Valves Associated with the 122 Spent Fuel Pool Heat Exchanger

On March 20 and 21, the licensee removed Emergency Diesel Generators (EDG) 1 and 2, respectively, from service to perform a check of the upper crankshaft thrust bearing. Additional work on EDG 2 included the replacement of two fuel injectors, the repacking of the air start valves, and the conversion of a low temperature lube oil heater shut off switch to a high temperature shut off switch. The inspector monitored various aspects of the maintenance activities including the restoration of EDG output breakers and the realignment of various valves. The fuel injectors were replaced to correct a condition which allowed fuel to bypass the injector due to bad seals. During engine testing it was determined that additional injectors need to be replaced.

The inspector witnessed the performance of SP 1093.4, D1 Diesel Generator Manual and 4 KV Voltage Rejection-Restoration Scheme Test, BRKR 15-2 Rack-In Verification and Bus 26 Load Test, Revision 3, and SP 2093.4, D2 Diesel Generator Manual and 4 KV Voltage Rejection-Restoration Scheme Test, BRKR 16-7 Rack-In Verification and Bus 25 Load Test, Revision 3. These procedures verified the operability of various relays in the plant load rejection and restoration scheme, verified the EDGs ability to carry approximately 2500KW and also satisfied independent verification that both output breakers associated with each EDG were properly racked in.

No violations or deviations were identified.

6. Surveillance (61726, 71707)

The inspector witnessed portions of surveillance testing of safety-related systems and components. The inspection included verifying that the tests were scheduled and performed within Technical Specification requirements,

by observing that procedures were being followed by qualified operators, that Limiting Conditions for Operation (LCOs) were not violated, that system and equipment restoration was completed, and that test results were acceptable to test and Technical Specification requirements.

SP 1116	Monthly Power Distribution Map
SP 1295	Emergency Diesel Generator D2 Manual Start and Bus 16 Load Rejection and Restoration
SP 1015	4KV Voltage & Frequency Test, Revision 12
SP 1089	Residual Heat Removal Pumps and Suction Valves From the Refueling Water Storage Tank, Revision 26.
SP 1102	11 Turbine-Driven Auxiliary Feedwater Pump Test, Revision 39
SP 1158	Charging Pump Desurger Test, Revision 12

The inspector witnessed the performance of surveillance procedure SP 1588, Charging Pump Desurger Test, Revision 12 on April 3, 1990. This procedure describes the steps necessary to check the desurger precharge and actions to take if the actual precharge pressure is less than required. The desurgers are utilized in the discharge line from the positive displacement charging pumps. Desurgers effectively eliminate water hammer common to positive displacement charging pumps. The charging pumps are considered operable with a failed desurger.

SP 1588 was performed on charging pumps No. 11 and 12, both of which were determined to have desurgers with failed bladders. Difficulties were encountered during the conduct of this surveillance due to extra valves on the tubing used to direct liquid to floor drains, lack of procedural direction to address high pressure indications on the desurger, and the confusion with the opening and closing of a valve in one step. These difficulties were conveyed to the system engineer with the surveillance results. SP 1588 is currently being revised with the assistance of the operations staff. This revision should greatly assist in the performance of SP 1588. Additionally, the system engineer is pursuing greater reliability of the desurger materials with the vendor.

It has been noted by the inspector that those surveillance, maintenance and operations procedures revisions written by a system engineer with significant input by those responsible for their usage are greatly improved over previous revisions. Although this process is more time consuming, the quality of the end product appears to justify the effort.

No violations or deviations were identified.

7. <u>ESF System Walkdown and System Focus (71710, 61626)</u>

The inspector performed a walkdown of the Unit 1 Auxiliary Feedwater System and observations included confirmation of selected portions of the licensee's procedures, checklists, verification of correct valve and power supply breaker positions to insure that plant equipment and instrumentation are properly aligned, and local system indication to

insure proper operation within prescribed limits. The inspector utilized C28-2, System Prestart Checklist, Auxiliary Feedwater System Unit 1, Revision 22 to conduct this walkdown. Several minor discrepancies were noted between the procedure and equipment tag nomenclature. The licensee has initiated action to correct these identified discrepancies.

The inspector witnessed the performance of Surveillance Procedure SP 1102, 11 Turbine-Driven Auxiliary Feedwater Pump Test, Revision 39, on March 28, 1990. SP 1102 fulfills monthly testing requirements of Technical Specification 4.8.A. The surveillance was successfully completed. The Plant Equipment Operator noted minor speed oscillations when the turbine was initially started with a duration of approximately 1 minute. These observations were documented on the cover sheet of SP 1102. Also recorded on the cover sheet was a notation reiterating pump seal leakage as having been previously documented on an outstanding work request. A review of these comments by the system engineer was conducted and the determination made that operability was not affected. The next performance of SP 1102 will be conducted in the presence of the maintenance staff and the system engineer for further evaluation. The inspector will continue to monitor surveillances and corrective actions associated with the auxiliary feedwater pumps. Activities associated with the auxiliary feedwater pumps have been previously documented in paragraph 4.d of Inspection Report Nos. 282/89031 and 306/89031(DRP).

8. Licensee Event Report Followup (92700)

a. (Open) Licensee Event Report (282/90003-LL):

LER 90003 was issued to document the auto-start of the No. 12 Diesel Cooling Water Pump (CWP) on low header pressure during a surveillance at approximately 0350 hours on March 23, 1990. The event was communicated to the NRC operation duty officer as required. The autostart has been attributed to a loss of prime on the No. 11 CWP and subsequent pressure degradation on the cooling water header. The loss of prime on No. 11 CWP was attributed to excessive air in leakage at the pump seals. Investigations into the seal water supply and air eductor system identified no problems. Improvements in the eductor system have been made with the replacement of all piping with stainless steel and the addition of a back-up rotary screw vacuum pump.

The auto-start of the No. 12 diesel cooling water pump occurred during the performance of SP 1106b, 22 Diesel Cooling Water Pump Test, Rev. 28. After completing the required run time and in preparation for stopping the 22 diesel cooling water pump, the procedure requires the pump which was stopped earlier to be restarted.

The procedure provides a note to the operators which states, in part, to be sure that the pump that was just started (21 CWP) has taken its share of the load by observing a header pressure increase

and a temporary speed increase on the diesel. The procedure further states that a failure to have the header pressure increase or diesel speed increase could mean that the pump is not primed and directs the operators to C35, cooling water system, for re-priming the pump. The operators determined that adequate indication of proper 21 CWP operation was observed and commenced the shutdown of the 22 diesel CWP. While reducing speed on the 22 diesel CWP, the cooling water header pressure decreased to 75 PSIG at which point the 12 diesel CWP autostarted. The operators then discovered that the 21 CWP had lost its prime. SP 1106b does not direct the operators to verify that the pump is primed as indicated by the local sight glass as is specified by C35, Cooling Water System.

Corrective actions associated with this event include examination of the 21 CWP air eductor, calibration of the pressure switch which starts the 121 CWP and increasing this setpoint to 80 PSIG cooling water header pressure. Previously the autostart setpoint was 75 PSIG for the 121 CWP and 75 PSIG with a 15 second timer delay for the autostart of the diesel cwp's. The increase to 80 PSIG for the 121 CWP autostart will help minimize autostarts of the diesel CWP when decreases in cooling water header pressure are experienced. The inspectors will followup licensee review and corrective actions by the Licensee Event Report (LER) 282/90003-LL.

It should be noted that on April 21, 1988, both the No. 12 and 22 Diesel Cooling Water Pump autostarted due to low cooling water header pressure. Low pressure occurred because the 11 CWP had become airbound and stopped pumping. Part of the corrective action for this event included the issuance of a PI Operations Note which briefly explained what had happened and provided special instructions for operating the eductor system and for checking to see that 11 and 21 were operating properly. While the inspectors do not consider the event of March 23, 1990 a repeat of the April 21, 1988 event, the inspectors feel that the corrective action taken should have addressed CWP operation during the performance surveillance procedures

9. Regional Meeting

On March 23, 1990, at 10:00 a.m. CST the licensee met with Region III management in the Regional Office in Glen E n, IL. The purpose of the meeting was to discuss lessons learned from the recent reactor trips. Mr. E.G. Greenman, Director, Division of Reactor Projects, led the discussion with the licensee. The licensee discussed: the root causes of the recent reactor trips, continued use of Westinghouse (BFD and NBFD) DC relays, vulnerability of the plant to secondary (steam side) surveillances, and actions to address electrical and instrument aging issues. In particular, the licensee discussed the plans to replace the NBFD relays which are installed in the Unit 2 RPS system (Unit 1 has more reliable BFD relays) during the upcoming (Fall 1990) refueling outage.

These plans are potentially impacted by product availability, modification engineering requirements and any change in the outage date. The personnel in attendance were as follows:

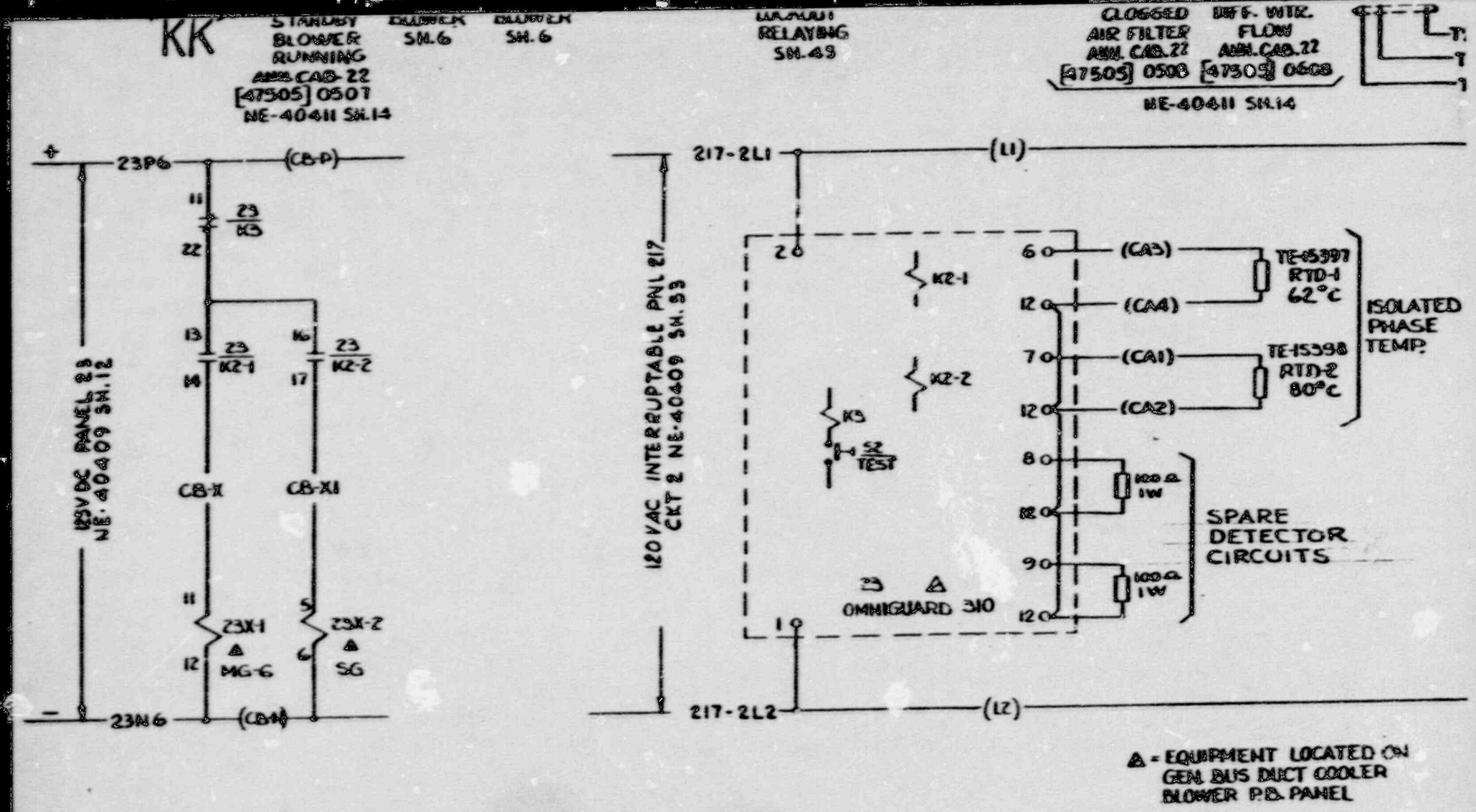
NSP	Title
C. Larson	Vice President Nuclear Generation
E. Watzl	Plant Manager - Prairie Island (PI)
D. Mendele	General Superintendent Engineering and Radiation Protection - PI
F. Beadell	Superintendent Technical Engineering - PI
R. Lindsey	Assistant to the Plant Manager - PI

NRC

E. Greenman	Director, Division of Reactor Projects, Region III
R. Cooper	Chief, Engineering Branch, Division of Reactor Safety, Region III
T. Burdick	Chief, Operator Licensing Section 2
D. DiIanni	License Project Manager, NRR
P Hartmann	Senior Resident Inspector - Prairie Island
E. Schweibinz	Project Engineer, Region III
D. Butler	Reactor Inspector, Region III

10. Exit (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the report period on April 12, 1989. The inspectors discussed the purpose and scope of the inspection and the findings. The inspectors also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any documents or processes as proprietary.



2 GENERATOR BUS DUCT COOLER BLOWER CONTROL

(X-HIAW 22-5)