U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-456/96002; 50-457/96002

FACILITY
Braidwood Nuclear Plant, Units 1 and 2

License Nos. NPF-72; NPF-77

LICENSEE
Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

DATES
December 30, 1995 through February 9, 1996

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13 March 1996
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and for certain previously identified items.

RESULTS

Assessment of Performance

The following assessments are based on activities during this report period. Operator performance during the Unit 2 loss of offsite power and the return to service of the 242-1 transformer was good. However, several equipment failures, such as the refueling water storage tank heater breaker, the pressurizer backup heater, and the volume control tank auto-make up valve controller required operators to take compensatory actions. The inspectors found material condition deficiencies, operator training deficiencies, and sampling procedure weaknesses with the containment air sampling panel. These deficiencies indicated uncertainties about the capability to accurately obtain a post accident air sample. Additionally, the inspectors identified numerous weaknesses with operating of the post accident neutron monitoring system including minimal operational testing and minimal operator training.

OPERATIONS

- On January 18, a Unit 2 loss of offsite power occurred when station auxiliary transformer (SAT) 242-1 failed and SAT 242-2 tripped as designed in response to the failure. The inspectors noted that the event was well handled by the control room staff (section 1.2).

- On January 23, during a 2A hydrogen monitor surveillance, a high flow condition was identified, however, the licensee considered the monitor operable. The inspectors questioned the lack of a technical basis for the operability determination. The licensee performed a more thorough evaluation and determined that their initial operability determination was incorrect and that the monitor was inoperable. The inspectors considered this an unresolved item pending further review (section 1.1).

- On February 15 and 16, SAT 242-1 and oil circuit breaker 11-14 were returned to service. The inspectors observed portions of the return to service and concluded that the activities were conducted in a controlled and conservative manner, with good procedure adherence, communications, and management oversight (section 1.2).

- Weaknesses in the licensee's contingency planning for a control room annunciator inverter replacement were noted (section 1.3).

- Operations response to a refueling water storage tank heater breaker failure was excellent. Use of the simulator to predict potential problems was particularly innovative (section 1.4).

- The inspectors identified numerous weaknesses with operating of the post accident neutron monitoring system including minimal operational testing and minimal operator training (section 1.10).

- On February 6, a Unit 1 overboration occurred due to a boric acid flow control valve failure (section 1.8). In addition, the inspectors identified that Unit 2 pressurizer relief tank high pressure alarms were not uncommon due to a longstanding valve leakage problem (section 1.6). Both events indicated that these two operator workarounds were not aggressively addressed, and in these cases, operators were not sufficiently diligent.

MAINTENANCE

- The licensee failed to take prompt corrective actions to prevent roofing materials from blowing off the service building roof, although previous occurrences of roofing materials and other debris blowing off the service building and turbine building roofs in the vicinity of the station transformers had been previously identified (section 2.1).

- During SAT maintenance, a ground strap was not re-connected following completion of the work. As a result, the restoration of the SAT was delayed about 8 hours (section 1.2).

ENGINEERING

- System engineering planning for a control room annunciator inverter replacement was good (section 3.1).

PLANT SUPPORT

- The inspectors identified numerous problems with the containment air sampling system including material condition deficiencies, operator training deficiencies, and sampling procedure weaknesses (section 4.1).

- The inspectors reviewed the emergency preparedness aspects of the loss of offsite power, and concluded that the licensee response was good (section 4.2).

Summary of Open Items

Violations: Identified in Sections 2.1 and 4.1
Unresolved Items: Identified in Section 1.1, 1.6
Inspection Follow-Up Items: Identified in Sections 1.2, 1.8, 2.2, and 2.3
Non-Cited Violations: Identified in Sections 1.9, 2.5, and 4.1

Summary of Closed Items

Violations: None identified
Unresolved Items: Identified in Sections 1.10 and 2.5
Inspection Follow-Up Items: Identified in Sections 1.10 and 2.5
Licensee Event Reports: Identified in Section 1.9

INSPECTION DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of plant operations.

1.1 Both Unit 2 Hydrogen Monitors Inoperable At about 5:30 a.m. on January 23, the licensee conducted Unit 2 operating surveillance BwOS 6.3.3-8, "Process Sampling Containment Isolation Valve Stroke Quarterly Surveillance," to verify, in part, that the 2A and 2B hydrogen monitoring system discharge check valves stroked open to ensure post accident operability. During the surveillance the following events occurred:

2A Hydrogen Monitor During the surveillance on the 2A hydrogen monitor, a system flow rate of 5.0 standard cubic feet per hour (scfh) was obtained which met the minimum acceptance criteria of 2.5 scfh. However, a note in the surveillance stated that a flow rate greater than 3.5 scfh indicated flow control problems in the instrument and that the instrument maintenance (IM) supervisor should be contacted.

Later that morning, after licensee personnel discussed the high flow with the IM supervisor, the licensee personnel concluded that the monitor was operable, and the flow would be adjusted during the next scheduled monthly surveillance on February 16, 1996.

2B Hydrogen Monitor During the surveillance on the 2B hydrogen monitor, a flow rate of 3.2 scfh was obtained which met the acceptance criteria and required no further actions. However, during a valve line-up restoration, a hydrogen monitor trouble alarm was received. The reactor operator de-energized, then re-energized the monitor, and the alarm did not come in. Subsequently, the licensee determined that a design system time delay prevented an alarm although a low flow condition existed, for four minutes after the system was reenergized.

During the following shift, the 2B hydrogen monitor failed the shift channel check and a trouble alarm was received in the control room. Operators and instrument maintenance technicians were dispatched and determined that the monitor flow throttle valves were mispositioned, causing a low flow condition, and the trouble alarm. These throttle valves were readjusted, proper flow was restored, and a channel check was completed satisfactorily.

On January 24, due to the previous trouble alarm, the shift engineer questioned the line-up on the 2B hydrogen monitor. In response, a walkdown of the 2B monitor was performed. During the walkdown, an operator checked the flow throttle valves and mistakenly closed the valves. A channel check was then performed, and a trouble alarm annunciated in the control room. Thirty-day Technical Specification (TS) Limiting Condition for Operation (LCO) action requirement 6.4.1.a was entered for the condition of having a single hydrogen monitor inoperable.

Work planning personnel subsequently scheduled maintenance department efforts to restore the flow throttle valves to a properly throttled position for January 31, a period of 7 days from discovery of the condition.

NRC Follow-Up On January 24, the resident inspectors were informed that the 2B hydrogen monitor was inoperable, and conducted a follow-up inspection. The following issues were identified:

2A Hydrogen Monitor During initial inquiries into the cause of the problems with the 2B hydrogen monitor, the inspectors became aware of the high flow condition of the 2A hydrogen monitor. Following discussions with licensee personnel, the inspectors determined that, following an initial informal determination by managers attending the morning work planning meeting that the 2A hydrogen monitor was operable, no formal operability determination was performed or planned. The inspectors questioned licensee personnel about the lack of a technical basis for the operability of the monitor. Subsequently, the licensee determined through conversations with the vendor, that their initial operability determination was incorrect and that the 2A hydrogen monitor was inoperable. Based on this new information, the licensee entered 30-day TS LCO 6.4.1.a for the 2A hydrogen monitor on January 23 at 0052; the time that the operating surveillance was commenced. In addition, the licensee entered 72-hour TS LCO 6.4.1.b for having both hydrogen monitors inoperable, at 0313 on January 24, the time when both Unit 2 hydrogen monitors became simultaneously inoperable.

Previous Occurrences In addition to the problems identified above, the inspectors and the licensee reviewed previously performed Unit 1 and Unit 2 hydrogen monitor discharge check valve stroke surveillances to determine if prior high sample flow rate conditions above 3.5 scfh were identified. Additional cases were identified as noted below:

- The licensee identified a 2B hydrogen monitor flow rate of 4.6 scfh on January 25, 1995. This condition existed for 11 days and was not corrected until February 5.

- The inspectors identified that a Unit 1 surveillance conducted on June 30, 1994, indicated a 1A hydrogen monitor flow rate of 4.4 scfh, and a 1B hydrogen monitor flow rate of 4.2 scfh. In addition, the licensee determined that proper 1A hydrogen monitor flow rate was not reestablished until July 18, a period of 18 days. The 1B hydrogen monitor was subsequently restored on July 26.

- The licensee identified a 2B hydrogen monitor flow rate of 5.2 scfh on April 19, 1993. This condition existed for 3 days and was not corrected until April 22.

- The licensee identified a 2B hydrogen monitor flow rate of 5.0 scfh on February 9, 1993, which was not corrected until April 22, a period of 41 days.

At the end of the inspection period, the licensee was obtaining information from the vendor concerning maximum flow limits for hydrogen monitor operability.

The inspectors planned to review additional information including information provided by the vendor. This is an Unresolved Item (96002-03), pending that review.

1.2 Unit 2 Loss of Offsite Power On January 18, a Unit 2 loss of offsite power (LOOP) occurred when station auxiliary transformer (SAT) 242-1 failed and SAT 242-2 tripped as designed in response to the failure. The 2A and 2B emergency diesel generators (EDGs) started, and supplied the safety-related 4.16 kilovolt busses as designed. Both units remained at 100 percent power throughout the event.

With some minor exceptions, plant equipment responded to the LOOP as expected. The inspectors noted that the event was well handled by the control room staff. However, there was a delay of about 45 minutes before the Shift Engineer briefed control room personnel on the event and the expected recovery actions. In addition, the procedure used (BwOA ELEC-4, "Loss of Offsite Power For All Modes) to transfer Unit 2 safety loads to Unit 1 and secure the EDGs needed a temporary change to allow a conservative, controlled transfer. The original procedure did not anticipate that the EDG's would be in the emergency mode when the transfer was to be accomplished. Licensee personnel stated that the procedure would be revised to incorporate these changes. The revised procedure will be reviewed as an Inspection Follow-up Item (96002-04).

The licensee's root cause investigation attributed the failure of SAT 242-1 to a phase-to-ground fault on the C phase transformer bushing followed by a C phase to B phase fault. Analysis of charred material on the C phase bushing identified Type 304 stainless steel, which is not used in the transformer. Analysis of an additional coating found on the bushing identified aluminum, which is used in a SAT gas pressure gauge damaged during the event. No stainless steel or aluminum residues were found on the B phase bushing. Although there was a storm with strong winds and lightning in the area at the time of the LOOP, plant instrumentation and damage to the SAT did not indicate a lightning strike. The licensee stated that the initial fault on the C phase bushing was likely due to debris containing stainless steel impacting or coming near the C phase bushing. Roof replacement had recently been completed on the turbine building roof, and was in progress on the service building roof. However, no debris from the roof was observed near the SAT after the LOOP although, as discussed in Inspection Report 95017, metal and insulation from roof repairs were found on and near a Unit 2 Unit Auxiliary Transformer on December 6 (see section 2.1).

In addition to the damage to the SAT, oil-circuit breaker (OCB) 11-14 in the main switchyard suffered the loss of some ceramic insulator material from one of two bushings on the B phase pole unit of the breaker (the breaker is composed of three separate and free-standing oil-filled tanks called pole units) and internal damage to the other bushing. Damage also occurred to internal metal components of both the B and C phase pole units.

The inspectors witnessed and reviewed results of licensee testing of SAT 242-2 prior to its return to service. The licensee performed an insulation resistance test (megger), turn-to-turn ratio test, low voltage excitation test and an oil sample analysis. In addition, high potential tests were performed on the 242-2 lightning arresters. Cell test results indicated that SAT 242-2 was not damaged during the event and could be safely returned to service. On January 20, the Unit 2 safety-related loads were transferred from Unit 1 to SAT 242-2, which had been tested and found not to be damaged. On February 15 and 16, SAT 242-1 and OCB 11-14 were returned to service. The inspectors observed portions of the return to service and concluded that the activities were conducted in a controlled and conservative manner, with good procedure adherence, communications, and management oversight. One problem identified by the licensee during the return to service was that a grounding strap had not been connected. This was promptly corrected and the Unit 2 safety-related loads were transferred back to the Unit 2 SATs late on February 16, restoring the electrical distribution system to the normal configuration.

Overall, the licensee's response to and recovery from the LOOP, including the repair of equipment and the control of plant configuration during the repairs and electrical system realignment, was good.

1.3 Annunciator Inverter Replacements On January 10, the licensee replaced two Unit 1 control room annunciator inverters, which rendered all nonsafety-related annunciators in the control room inoperable for about 5 minutes. The inspectors reviewed the licensee's planning and execution of this evolution and identified the following weaknesses in the licensee's contingency plan in the unlikely event that the annunciators could not be restored following inverter replacement:

- During the licensee's heightened level of awareness (HLA) briefing, consideration of potential problems and actions in the event of a long term loss of annunciators was not thoroughly considered or discussed.

- The licensee did not have replacement power distribution panel fuses in hand if the existing fuses failed when re-energized.

The licensee acknowledged the lack of contingency planning. The licensee planned to address the potential for longer term unavailability of the annunciators in the subsequent pre-job HLA and planned to identify all the necessary parameters for in the field observation if the annunciators were to remain inoperable for longer than three to five minutes.

1.4 Refueling Water Storage Tank (RWST) Heater Breaker Failure On January 8, the licensee energized the Unit 1 RWST heater following RWST sampling activities. A short time later an operator observed smoke issuing from the motor control center associated with the heater. The problem was identified as a burned out RWST heater breaker spring release coil. The inspectors reviewed the licensee's response to the event, and concluded that operator actions were excellent. In particular, operators requested a simulator response to the loss of the bus associated with the heater to determine which loads would be lost in the event of a loss of the bus. Although information as to what loads are on any bus was available on control room design drawings, the information was obtained faster with a better appreciation as to what the actual ramifications would be from the simulator. As a result, the licensee was able to plan for the loss of the bus, although it did not occur. The breaker was subsequently repaired and returned to service without incident.

1.5 Pressurizer Backup Heater Failure On January 9, the Unit 2 reactor operator (RO) identified that the pressurizer spray valves unexpectedly closed. Further review of the control panel identified that the group A backup heaters for the pressurizer were not energized. An alternate heater bank was placed in service and the spray valves returned to their normal position. Operations, electrical maintenance, and system engineering personnel were then dispatched to the breaker panel for the heater and identified that a coil in the 480-volt distribution panel for the heater had failed. The coil was subsequently replaced and the heater was returned to service. The failure was attributed by the licensee to age-related degradation of the coil. Although the heaters were designated as backup components in the Updated Final Safety Analysis Report (UFSAR) they were energized nearly all the time, and had been in service since initial criticality. As a followup to the problem, thermography of the other heater breakers and distribution panels was conducted to identify any incipient problems. None were found.

UFSAR Section 7.7.1.5, "Pressurizer Heater Control," implies that the proportional pressurizer heaters are predominantly utilized to correct small pressure variations and the backup heaters cycle when proportional heater power demands are about 100 percent. In practice, however, two sets of backup heaters are manually continuously energized to cause a greater spray flow than originally designed to promote better chemical mixing and stratification in the pressurizer spray line. As a result, proportional heater power demand is minimal. The inspectors concluded this was an acceptable practice.

The inspectors, who observed most of the control room activities and the initial investigation at the distribution panel, concluded that the response of the operations, electrical maintenance, and system engineering personnel to the equipment failure was excellent. The thermography of the other breakers and panels was good followup action.

1.6 Unit 2 Pressurizer Relief Tank Level Adjustments During a review of the Unit 2 control room logs, the inspectors noted that a high pressure alarm for the pressurizer relief tank (PRT) was received on January 30 and 31. A review of computer data indicated that the alarm had also come in the previous two days. Reactor operators stated that it was not uncommon for the alarm to come in and that it was usually due to a level increase. The reactor operators indicated the source of the input was likely due to leakage of primary makeup water through PRT containment isolation valve, 2AOV-RY8030. The required operator actions in the alarm response procedure, BwAR 2-12-B7, "Pressurizer Relief Tank Pressure High," required initiation of corrective actions for suspected equipment problems. However, discussions with plant personnel indicated that no corrective actions, such as the writing of an action request, had been taken in response to these alarms. The work request history for the valve indicated it was worked on in 1993 for suspected leakage. The apparent lack of timely corrective actions was discussed with licensee management who indicated that the problem with the valve had been the subject of recent internal discussions. The the extent of corrective actions from those discussions will be reviewed as an Unresolved Item (96002-05).

1.7 Procedure Review On February 2, in preparation for raising level in the Unit 2 safety injection accumulators, ROs reviewed procedures BwOP SI-5, "Raising SI Accumulator Level with SI Pumps," and BwOP SI-9, "Lowering SI Accumulator Pressure," and identified a step in BwOP SI-9 that incorrectly required closure of a valve. The ROs discussed the error with the Unit 2 Unit Supervisor, and the level adjustment was postponed until the procedure was changed. The inspectors, who observed the procedure review and identification of the problem, concluded that the ROs conducted a thorough review of the operating procedures and took appropriate actions to correct an identified problem.

1.8 Unit 1 Overboration On February 6, during a normal automatic makeup, the Unit 1 reactor coolant system was overborated and system average temperature (T-ave) dropped from 585 degrees Fahrenheit (°F) to 581 °F. The overboration occurred when 1CV110A, the boric acid flow control valve, opened too far and allowed a flow of 40 gallons per minute (gpm) rather than the 14 gpm set on the boric acid flow controller. The RO who was monitoring the makeup did not notice the higher than expected flow until the makeup was completed. The RO and the Unit 1 Unit

Supervisor then diluted the reactor coolant system to return T-ave to normal. The automatic makeup is the automatic addition of a blend of boric acid and primary water to maintain a specified level in the volume control tank.

The inspectors concluded the safety significance of this particular event was minor, nonetheless, licensee management responded aggressively. The individuals involved in the event were counselled, the event was discussed with all of the operating crews, troubleshooting was conducted on the flow controller, and alarm response procedures BwAR 1-9-A6, "BA Flow Deviation," and BwAR 1-9-B6, "PW Flow Deviation," will be revised to enhance operator response. The purpose of the alarms is to alert ROs that boric acid and primary water flow rates are not within specified limits. The results of the troubleshooting and the procedure revision will be reviewed as an Inspection Follow-up Item (96002-06).

Several problems highlighted by this event are discussed below.

- For many years, boric acid flow and primary water flow deviation alarms have occurred at the start of auto-makeups, requiring operator action to prevent automatic closure (in 15 seconds) of 1CV110B, the boric acid blender to charging pumps isolation valve, and 1CV111B, the boric acid blender to volume control tank isolation valve, and unwanted cessation of the auto-makeup. Typically, the alarms occurred because the boric acid and primary water flow control valves did not modulate to the position necessary to obtain the specified flow within the 15-second limit. This was identified several years ago as an operator workaround, but had not been corrected.

- The RO in this event initially checked boric acid flow rate during the makeup, but not thereafter. During the first minute or so of the makeup, the flow rate was as expected, but subsequently increased.

- The pen for the flow rate strip chart was not inking; however, the position of the pen after the first minute or so clearly indicated that flow rate was higher than expected.

The inspectors concluded that the event demonstrated how operator workarounds can lead to errors. Although the RO took the appropriate actions in response to the known problem with initial makeup flow, he did not respond appropriately when flow subsequently increased, because he was busy prevent the unwanted, automatic cessation of the makeup. This event and the problem with the PRT (section 1.6) indicated that these two operator workarounds were not aggressively being addressed, and operators made errors as a result.

1.9 Follow-up on Non-Routine Events NRC Inspection Procedures 90712 and 92700 were used to perform a review of written reports of non-routine events.

(Closed) LER 50-456/95012, Revision 0 and 1: Management Decisions Led to Positive Reactivity Events While Shutdown with One Source Range Nuclear Instrument Inoperable. During a refueling outage with Unit 1 in Mode 5 and one source range nuclear instrument inoperable, TS 3.3.1 required that no positive reactivity additions occur. However, between October 4 and 5, two events occurred which added positive reactivity. In the first event, a reactor coolant pump was started and secured which caused a temperature oscillation and resulted in a slight positive reactivity addition. In the second case, makeup to the reactor coolant system from the refueling water storage tank which was at a slightly lower boron concentration was made, which resulted in a slight positive reactivity addition.

The inspectors reviewed both events and concluded that the safety significance was minimal. Both events represented minor positive reactivity additions and reactor coolant system (RCS) boron concentration during the events were well in excess of shutdown margin requirements.

As part of the licensee immediate corrective actions, all subsequent RCS additions were made from a source with a boron concentration which exceeded that of the RCS. In addition, no further reactor coolant pump evolutions were performed while the source range nuclear instrument remained inoperable. As part of the long term corrective actions, the licensee planned to include a TS change to allow operations in Modes 3, 4, and 5, if one source range channel is inoperable without limiting reactivity excursions of this type. The inspectors reviewed the licensee's corrective actions and concluded the licensee's actions were acceptable.

The events as described above were an example where LCO action requirements associated with TS 3.3.1 were not met, a violation. However, this licensee-identified and corrected violation is being treated as a Non-Cited Violation (96002-07), consistent with Section VII of the NRC Enforcement Policy.

(Closed) LER 50-456/95015, Revision 0: Degradation of Steam Generator Tubes Exceeds Technical Specification Limit. On October 7, 1995, a Unit 1 steam generator tube inservice inspection was conducted. As a result of that inspection, the licensee identified that the 1A, 1B, 1C, and 1D steam generators had degraded, and in accordance with TS, a report to the NRC was required.

Subsequently, on November 9, 1995, the NRC granted the licensee a revised steam generator tube 3.0 volt interim plugging criteria (IPC). The inspectors determined that if this IPC had been effective at the time of the inspection, the data obtained during the inservice inspection would not have required a report. As a result, the inspectors concluded that the inservice inspection results had minimal safety significance.

To address concerns with the premature degradation being experienced with the Unit 1 Westinghouse D-4 steam generators, the licensee planned to replace these generators in September 1998. In the interim, the licensee has established a program to reduce the rate at which these steam generator tubes are degrading, and planned to perform additional steam generator tube inspections at an increased frequency. This LER is closed.

<u>(Closed) LER 50-456/95016, Revision 0</u>: Reactor Trip Inserted During Digital Rod Position Indication (DRPI) Operability Testing Due to a Blown Stationary Gripper Fuse. On November 17, 1995, with Unit 1 in Mode 5, DRPI operability testing was in progress. During withdrawal of control bank "B", all rods withdrew from fully inserted to an indicated position of 12 steps with the exception of control rod K-12 which indicated 0 steps withdrawn. As a result of the unexpected indication, the licensee opened both reactor trip breakers and all control rods inserted as designed. Subsequently, the licensee identified that the stationary gripper fuse associated with control rod K-12 had blown, preventing the rod from being withdrawn. The fuse was replaced and the DRPI testing was completed satisfactorily.

The inspectors reviewed this event, determined that no administrative or TS requirement directed the opening of the reactor trip breakers, and concluded that the licensee's decision was conservative. This LER is closed.

<u>(Closed) LER 50-456/95017, Revision 0</u>: Reactor Trip Inserted During Rod Control System Testing Following Receipt of an Urgent Failure Alarm on Shutdown Bank E. On December 12, 1995, with Unit 1 in Mode 3, rod drop testing was in progress in preparation for reactor startup. During withdrawal of shutdown bank E, a rod control urgent failure alarm was received which prevented the rods from being manually stepped. As a result of the unexpected alarm, the licensee opened both reactor trip breakers and all rods inserted into the core as expected. Subsequently, the licensee identified a suspected failed failure detector card for shutdown banks C, D, and E. This card was replaced and no further problems were noted.

The inspectors reviewed this event, determined that no administrative or TS requirement directed the opening of the reactor trip breakers, and concluded that the licensee's decision was conservative. This LER is closed.

<u>(Closed) LER 50-456/95018, Revision 0</u>: Reactor Trip Inserted During Rod Control System Testing Following a Failure of Shutdown Rod D-2 to Withdraw on Demand. On December 7, 1995, with Unit 1 in Mode 3, a DRPI operability verification prior to rod drop testing was in progress. During withdrawal of shutdown bank A, control rod D-2 failed to withdraw. As a result of the unexpected condition, the licensee

opened both reactor trip breakers and all rods inserted into the core as expected. The followup investigation by the licensee did not identify the cause of the failure of control rod D-2 to withdraw. As a precautionary measure, all fuse holders associated with the rod were cleaned and the fuses were replaced with new ones. Subsequently, the surveillance was resumed and no additional problems were encountered.

The inspectors reviewed this event, determined that no administrative or TS requirement directed the opening of the reactor trip breakers, and concluded that the licensee's decision was conservative. This LER is closed.

(Closed) LER 50-456/95019, Revision 0: Manual Reactor Trip Initiated During Rod Drop Testing Due to Failed Testing Relays. On December 7, 1995, with Unit 1 in Mode 3, rod drop testing was in progress. During the testing of control rod bank D, rods D-12, M-4, and H-8, remained at the fully withdrawn position when a drop signal was initiated. All other rods dropped as expected. As a result of the unexpected condition, the reactor trip breakers were opened and all rods fully inserted as expected. Subsequently, the licensee determined that relay contacts associated with the automatic rod drop testing equipment did not function properly, and as a result, the rods did not receive a drop signal.

Shortly thereafter, the licensee attempted automatic rod drop testing for shutdown bank C. The rods were fully withdrawn and a rod drop signal was initiated, however, the bank failed to insert as expected. As a result, the licensee opened the reactor trip breakers and the rods fully inserted. A followup investigation identified that relay contacts associated with the automatic rod drop testing equipment did not function properly. Subsequently, the licensee elected to discontinue the automatic testing and testing was completed manually.

The inspectors reviewed this event, determined that no administrative or TS requirement directed the opening of the reactor trip breakers, and concluded that the licensee's decision was conservative. In addition, since the failed relays were used only during automatic rod drop testing and do not affect normal rod control circuitry, the inspectors concluded that this event had minimal safety significance. This LER is closed.

1.10 Follow-up on Previously Opened Items A review of previously opened items was performed per NRC Inspection Procedure 92901.

(Open) Inspection Follow-Up Item 95017-04: Post Accident Monitoring System. As discussed in inspection report 95017, the inspectors reviewed the licensee's operation of the post accident neutron monitoring (PAM) system. The system provides indication of neutron flux during post accident conditions if the normal nuclear instruments are unavailable, since they are not environmentally qualified.

As a result of that review, the inspectors identified concerns with the licensee's surveillance and calibration program, as well as operator training. During this inspection period, the following additional information was obtained and licensee actions were initiated or planned:

- Surveillance and Calibration Testing The inspectors noted in inspection report 95017 that the PAM system is calibrated on an 18-month frequency. However, between calibrations no log readings or surveillances tests were performed to verify that these instruments were operating properly. The licensee planned to incorporate a surveillance program to provide a more frequent verification that the PAM system was operating properly.

- Operator Training As described in inspection report 95017, the inspectors discussed training with licensee personnel and concluded that minimal classroom training was provided on the operation and use of this system. In addition, the inspectors identified that simulator training did not incorporate the use of the PAM system into accident scenarios. After the inspector's inquiries, the licensee revised their training program and planned to begin training on the PAM system during the next operator training cycle.

- Emergency Operating Procedures The inspectors reviewed the licensee's emergency operating procedures (EOPs) and discussed incorporation of the PAM system into the EOPs with licensee personnel. The inspectors determined that the licensee's EOPs did not address the use of the PAM system to mitigate an accident, although the normal nuclear instrumentation system referenced in the EOPs was not environmentally qualified and therefore may not be available during an accident. The licensee planned to incorporate the PAM system into the EOPs. However, human factor engineering problems exist with the equipment. For example, the source range meter reads out in counts per second. From just this indication the operator cannot easily determine whether the reactor is subcritical. The extent of hardware changes necessary has not been determined, as such, how the PAM system will be incorporated into the EOPs has not yet been determined.

The inspectors concluded from the above observations that licensee personnel paid little attention to a required post accident monitoring system. However, it appeared no regulatory requirements were violated. The inspectors reviewed the new approved training plan and interviewed the EOP coordinator and concluded that the licensee's planned actions to improve the maintenance, knowledge and procedural usage were good. This item will remain open until the licensee determines when and how the PAM system will be included in the EOP's.

(Closed) Unresolved Item 95015-02: Positive Reactivity Controls. As described in inspection report 95015, the licensee identified two events which caused positive reactivity additions in violation of TS 3.3.1. As a result, LER 50-456/95012 was generated and will be used to track this issue (see section 1.9). This item is closed.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and testing activities.

2.1 Control of Debris from Roofing Work As discussed in inspection report 95017, the licensee identified two instances (November 30 and December 6, 1995) where debris from repairs to the roofs of the turbine and service buildings apparently blew from the roofs onto a unit auxiliary transformer. After those events, personnel associated with the work were counselled on the need to improve control over the roofing materials. Subsequently, on January 17, the licensee and the inspectors observed large pieces of insulation being blown off the roof, but not in the direction of the transformers. The licensee sent personnel to the roof to secure the material. However, on January 18, the licensee and the inspectors again observed pieces of insulation being blown off the roof, not in the direction of the transformers. The licensee again sent personnel to secure the material. Several minutes after the inspectors' observations, a LOOP occurred on Unit 2 (see section 1.2), caused by the failure of SAT 242-1. The inspectors noted after the LOOP that the wind direction had shifted towards the transformers.

Subsequent analyses by the licensee of charred material found on the C phase bushing of the SAT 242-1 identified traces of stainless steel, consistent with the composition of flashing used in roof repairs. And although, no debris from the roof was found near any of the Unit 2 transformers, the licensee's investigation concluded that foreign material, possibly flashing from the service building roof, caused the failure of SAT 242-1. The failure to correct the problem on November 30, December 6, and January 17 was a violation of Criterion XVI, "Corrective Action," of 10 CFR 50, Appendix B (96002-01).

2.2 1B Centrifugal Charging Pump Maintenance On January 11, during performance of a 1B centrifugal charging (CV) pump surveillance, oil filter differential pressure increased to an abnormal value and the pump was secured. Subsequently, the licensee inspected the oil filter and identified paint chips in the oil. The following day, the oil reservoir was inspected and a 2-inch length of tygon hose as well as a small quantity of paint chips, some dirt, and metal shavings were discovered in the bottom of the reservoir. This is an Inspection Follow-up Item (96002-08) pending review of the licensee's root cause investigation.

2.3 1B Condensate Booster Pump Failure On January 26, during a routine inspection of the Unit 1 condensate/condensate booster (CD/CB) pumps, a field supervisor noted no oil return flow on the 1B CB pump inboard bearing. This pump had recently been rebuilt as part as an effort to improve the material condition of these pumps. Shortly afterward, the inboard bearing temperature increased rapidly. Following a power reduction, and a transfer to another available pump, the 1B CD/CB pump was secured.

Subsequently, mechanical maintenance department (MMD) personnel disassembled the pump bearing, and identified that the babbitt material on the internal bore of the bearing had been significantly damaged and that the pump shaft around the bearing had a groove in it. In addition, MMD personnel opened the lube oil sump and identified babbitt and other debris. At the end of the inspection period, the licensee had not identified a root cause for the bearing failure. This is an Inspection Follow-up Item (96002-09) pending a review of the licensee's root cause investigation.

2.4 2B Residual Heat Removal (RHR) Pump Out of Service Time Extended The 2B RHR pump was removed from service on January 22, for scheduled maintenance to replace the pump seal. The pump was scheduled for return to service on January 24. However, with one ceiling plug removed and the pump rigged for lifting, the job foreman decided to lift a second ceiling plug. Because the pump was rigged for lifting the pump motor dust cover was removed. When the second ceiling plug was lifted, debris fell into the pump motor casing. In addition, during the attempt to remove the pump impeller, mechanical maintenance personnel experienced difficulties. Three shifts were expended in the attempt to remove the impeller. In the process the pump shaft was gouged and bent. Vendor guidance on how to remove the pump impeller from the shaft was not obtained until the pump shaft was already damaged. Because of these problems the licensee replaced the motor, shaft, and impeller. The time that the 2B RHR pump was out of service was extended from three days to six days and was returned to service on January 27.

The inspectors reviewed pictures of the damage to the pump and interviewed several foremen on the job in addition to work control personnel. The inspectors concluded that the 2B RHR pump seal replacement was performed with insufficient skill and supervision. As a result, the pump out of service time was prolonged.

2.5 Follow-up on Previously Opened Items A review of previously opened items was performed per NRC Inspection Procedure 92902.

(Closed) Unresolved Item 95015-05: Safety-Related Lube Oil Cooler Head Positioning Errors. On October 6, 1995, during a routine lube oil cooler inspection, maintenance workers identified that the 1A essential service water (SX) pump lube oil cooler return head was rotated 90 degrees from its required position, which isolated all SX flow to the cooler. Subsequently, the workers identified that the 2A SX lube oil cooler head was also mispositioned. On October 10, the inspectors were informed of the event. They independently identified that the 2A safety injection pump and the 1B CV pump lube oil cooler heads were also rotated 90 degrees, which isolated 50 percent of the flow to the cooler. Subsequently, the licensee identified that the 2B auxiliary feedwater pump lube oil cooler head was also incorrectly positioned.

The licensee performed an engineering evaluation and determined that all the coolers with mispositioned heads remained operable. The inspectors reviewed this evaluation and concurred with the licensee's conclusions. As a result, the inspectors concluded that the event had minor safety significance.

The licensee performed an investigation and determined that the root cause of the event was inadequate work package instructions. Specifically, the work package for reassembly of the coolers did not contain drawings to indicate correct cooler head orientation.

As part of the licensee's immediate corrective actions, the cooler heads identified above were correctly oriented and walkdowns were conducted which verified that no other cooler heads were mispositioned. As part of the licensee's long term corrective actions, maintenance work packages will be revised to contain drawings for clarification of proper head position. The inspectors reviewed the licensee's planned corrective actions and have no further concerns.

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be prescribed by instructions and drawings appropriate to the circumstances. The failure to incorporate drawings or instructions for proper cooler head orientation is an example where this requirement was not met. However, this problem had minor safety significance and is being treated as a Non-Cited Violation (96002-10), consistent with Section IV of the NRC Enforcement Policy.

<u>(Closed) Inspection Follow-Up Item 95013-03</u>: On-Line Maintenance Planning and Execution. As a result of delays encountered during on-line maintenance of several safety-related systems, the licensee conducted a lessons learned assessment.

The inspectors reviewed the assessment which identified deficiencies in management of the planning and execution of the work, procedure inadequacies, and failures to self check. To address these concerns, the licensee revised the station's procedure adherence policies and trained all site personnel on the revised policy. In addition, reinforcement sessions to stress the importance of self-checking were held with all licensee employees. Finally, the station recently revised the work planning process to address concerns with planning and execution of maintenance. Basic changes included an increase in the planning cycle to 12 weeks, the addition of a work week manager to follow work to completion, and additional supervisor involvement during work planning and execution. The inspectors concluded that the licensee's initiatives appeared to address the problem if effectively implemented. This item is closed.

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of engineering.

3.1 Annunciator Inverter Replacements As described in Section 1.3, the licensee replaced two Unit 1 control room annunciator inverters which rendered all nonsafety-related annunciators in the control room inoperable for about five minutes. The inspectors evaluated the maintenance actions prescribed by the system engineer and noted that well thought out planning was done to minimize the time that the annunciators would be deenergized and unavailable.

3.2 Follow-Up On Previously Opened Items NRC Inspection Procedure 92903 was used to perform a follow-up inspection of the following item:

(Open) Inspection Follow-Up Item 95017-05: Steam Generator Power-Operated Relief Valve (PORV) Circuit Breaker Problems. As discussed in inspection report 95017, the licensee recently identified the existence of an electronic circuit breaker in the control circuitry of the steam generator PORVs. At that time, the breaker for the 2D PORV was found inexplicably open and how long it was open was indeterminate. Since then, the breaker for the 2D PORV opened two more times, once on January 12 and once on January 13. At of the end of the inspection, troubleshooting of the 2D PORV circuitry was ongoing. This item remains open.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750 and 84750 were used to perform an inspection of Plant Support activities.

4.1 Chemistry

Containment Air Sampling Panel (CASP) The inspectors performed a walkdown of the Unit 1 and Unit 2 Containment Air Sample Panels (CASPs) and observed the licensee obtain two containment air samples. The following issues were identified:

Walkdown Observations The inspectors identified numerous minor material condition and housekeeping weaknesses:

- Numerous Unit 2 CASP panel equipment markings and valve labels were incorrect, and did not correlate to equipment and valves referred to in the sampling procedure.

- Numerous CASP panel minor material condition and housekeeping problems were identified, including missing light bulb covers, burned out indicating lights, and graffiti.

- Various unnecessary tools and other equipment were discovered inside the Unit 1 CASP panel.

The inspectors informed the licensee of the problems and action requests were written to correct the material condition problems.

Containment Air Sampling Observations The inspectors observed licensee personnel obtain two containment air samples using the CASP system. The following issues were identified:

- Procedure Adherence Weakness BwCP 703-1, "Initial Requirements for Post Accident Sampling of Reactor Coolant, Radwaste, and Containment Air," required that each post accident procedure be initialed as each step was performed. However, during collection of a Unit 2 sample using BwCP 703-21, "Post Accident Sampling of Containment Atmosphere," steps were not initialed as each step was performed.

  10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality be accomplished in accordance with appropriate procedures. The failures to initial step as described above are examples where this requirement was not met. However, this failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (96002-11), consistent with Section IV of the NRC Enforcement Policy.

- Wrong Unit Error During collection of the Unit 1 containment air sample, the chemistry technician attempted to operate a switch on the Unit 2 CASP panel, when he was not supposed to operate it. The inspectors brought this error to the attention of the technician prior to operation of the switch.

Procedure Weaknesses The inspector reviewed the licensee's procedure to sample containment following an accident BwCP 703-21, Revision 1, "Post Accident Sampling of Containment Atmosphere in The Manual Mode of Operation." The following issues were identified:

- The inspectors identified numerous nomenclature, typographical, and other errors. The inspectors concluded that these deficiencies could unnecessarily challenge the operator.

- The inspectors identified that no alarm response procedures existed for the eight local alarms associated with the CASP although operators had been responding to these alarms since system installation. In addition, licensee personnel stated that no formal training was provided to the technicians concerning how to appropriately respond to CASP alarms. The inspectors concluded that licensee training and response procedures associated with the CASP alarms were poor.

- The inspectors identified that important information had not been incorporated into the CASP sampling procedures. The Updated Final Safety Analysis Report, Appendix E, Section E.2 stated in part that containment sample lines were heat traced to prevent condensation of the sample inside the sample lines and that this design feature was necessary to obtain a representative sample. The vendor manual, "Sentry High Radiation Sampling System Operations and Maintenance Manual," May 1981, stated that special measures were employed to prevent particulate and iodine plateout in the inlet line. One of these special measures was that a thermostatically controlled electric heating cord to maintain the surface temperature of the inlet line at either 150 degree Fahrenheit (F) (routine) or 300 degree F (accident). Specifically, the vendor manual recommended preoperational check list (Section X) directs the operator to verify that the Heat Trace Temperature Select Switch is in the 150 degree F or 300 degree F position. Also, to verify that the sample line temperature has reached the desired value by observing that the White Line Temperature Correct pilot light turned on.

  The inspectors observed licensee personnel perform the regular quarterly surveillance sample using BwCP 703-21, Revision 1, "Post Accident Sampling of Containment Atmosphere in The Manual Mode of Operation." The technician turned on the heat tracing but did not wait 1 hour as recommended by the procedure. The procedure did not contain a step to verify that sample line temperature was adequate through observation that the sample line temperature correct pilot light had turned on. The technician recorded the sample line temperature, however, there was no acceptance criteria given in the procedure. The inspectors concluded that the surveillance as performed did not adequately determine that the sample line heat trace control was functioning as designed.

10 CFR 50, Appendix B, Criterion XI, requires a test program to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Failure to include sample line temperature verification is a violation of this requirement (96002-02).

4.2 Emergency Preparedness Response To The Loss Of Offsite Power The inspectors reviewed the emergency preparedness aspects of the LOOP (section 1.2) and concluded that the licensee response was good. The inspectors observed the station's two emergency preparedness specialists in the control room shortly after the LOOP assisting control room personnel with event classification and notifications. The event was properly and timely classified on January 18 in accordance with the licensee's Generating Stations Emergency Plan as an Unusual Event for the loss of all offsite power for 15 minutes or more; and the event was properly terminated on January 20 when the Unit 2 safety-related 4.16 kilovolt buses were transferred from Unit 1 to Unit 2 SAT 242-2. The inspectors also verified that notifications were made in accordance with 10 CFR 50.72.

5.0 REVIEW OF UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. During a portion of the inspection (February 1-9, 1996) the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas discussed in this report. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

UFSAR Section 7.7.1.5, "Pressurizer Heater Control," implies that the proportional pressurizer heaters are predominantly utilized to correct small pressure variations and the backup heaters cycle when proportional heater power demands are about 100 percent. In practice, however, two sets of backup heaters are manually continuously energized to cause a greater spray flow than originally designed to promote better chemical mixing. As a result, proportional heater power demand is minimal. The inspectors concluded that operation of the back-up heaters in this manner was acceptable.

6.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on February 9, 1996, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

K. Kaup, Site Vice President
*T. Tulon, Station Manager
*A. Haeger, Chemistry/Radiation Protection Director
W. McCue, Support Services Director
*R. Flessner, Site Quality Verification Director
B. Byers, Maintenance Superintendent

D. Skoza, Engineering Superintendent
*D. Miller, Work Control Superintendent
*T. Simpkin, Regulatory Assurance Supervisor
H. Cybul, System Engineer Supervisor
*J. Meister, Engineering Manager
D. Cooper, Operations Manager
*L. Weber, Shift Operations Supervisor
M. Turbak, Independent Safety Engineering Group Supervisor
*E. Roche, Executive Assistant to the Site Vice President
*H. Pontius, Jr., Nuclear Licensing Administrator
*J. Nalawajka, Integrated Analysis Administrator
*J. Lewand, Regulatory Assurance - NRC Coordinator

7.0 VIOLATIONS FOR WHICH A "NOTICE OF VIOLATION" WILL NOT BE ISSUED

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of the NRC Enforcement Policy. These tests are: 1) the violation was identified by the licensee; 2) the violation would be categorized as Severity Level IV; 3) the violation will be corrected, including measures to prevent recurrence, within a reasonable time period; and 4) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation. Violations of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued are discussed in sections 1.9, 2.5, and 4.1.

8.0 DEFINITIONS

8.1 Inspection Follow-up Items Inspection Follow-up Items are matters which have been discussed with the licensee, which will be reviewed by the inspector and which involve some action on the part of the NRC or licensee or both. Inspection Follow-up Items disclosed during the inspection are discussed in sections 1.2, 1.6, 1.8, 2.2, and 2.3.

8.2 Unresolved Items Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An Unresolved Item disclosed during the inspection is discussed in section 1.1.

D. Skoza, Engineering Superintendent
*D. Miller, Work Control Superintendent
*T. Simpkin, Regulatory Assurance Supervisor
H. Cybul, System Engineer Supervisor
*J. Meister, Engineering Manager
D. Cooper, Operations Manager
*L. Weber, Shift Operations Supervisor
M. Turbak, Independent Safety Engineering Group Supervisor
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