U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-454/94025(DRP); 50-455/94025(DRP)

Docket Nos. 50-454; 50-455 License Nos. NPF-37; NPF-66

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

Facility Name: Byron Station, Units 1 and 2

Inspection At: Byron Site, Byron, Illinois

Inspection Conducted: October 21, 1994 through December 15, 1994

Inspectors: H. Peterson
C. H. Brown
N. D. Hilton

Approved By: [signature] 6 JAN 95
Lewis F. Miller Jr., Chief Date
Reactor Projects Branch 1

Inspection Summary

Inspection from October 21, 1994 through December 15, 1994 (Report Nos. 50-454/94025(DRP); 50-455/94025(DRP)).
Areas Inspected: Routine, unannounced safety inspection by the resident inspectors and others of the regional office of plant operations, plant support, maintenance and surveillance activities, engineering and technical support, and reports review.

Results: Of the five areas inspected, one violation, one unresolved item and one inspection follow up item were identified. The violation pertained to the failure to follow procedures to control overtime (paragraph 2.6). The unresolved item pertained to the adequacy of environmental qualification of Okonite taped cable splices (paragraph 5.3). The inspection follow up item was to follow the licensee's trend evaluation, and review the foreign material exclusion controls for the upcoming Unit 2 refueling outage, scheduled for February 1995.

9501190050 950106
PDR ADOCK 05000454
G PDR

DETAILS

1.0 MANAGEMENT INTERVIEW (71707)

The inspectors met with the licensee representatives denoted in paragraph 7, both during the inspection period and at the exit interview conducted by the Senior Resident Inspector on December 15, 1994. The inspectors summarized the scope and results of the inspection and discussed the likely content of the report as described in these details. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

1.1 PLANT OPERATIONS

Overall, the licensee's awareness of plant safety continued to be good. During this inspection period, the licensee demonstrated good communications and coordination, with respect to several operational concerns. These concerns were the major Unit 1 condenser tube leak and subsequent chemical contamination of the Unit 1 steam generators, safety injection accumulator filling, a feedwater leak from the 1A motor driven feedwater pump during Unit 1 startup after the refueling outage, and overtime deviation review. One violation was identified concerning the overtime deviation authorization. Detailed discussions are found in paragraphs 2.3 through 2.6.

1.2 PLANT SUPPORT

Overall, the performance in the area of plant support continued to be good. The chemistry organization performed very well during the Unit 1 condenser tube leak and subsequent chemistry excursion and secondary side cleanup.

1.3 MAINTENANCE AND SURVEILLANCE

Performance in this are was considered to be satisfactory. Foreign material exclusion (FME) controls were reviewed per NRC Temporary Instruction 2515/125. The plant FME controls were considered satisfactory. An inspection follow up item was initiated to follow the licensee's trend evaluation and review any improvements to the foreign material exclusion controls for the upcoming Unit 2 refueling outage, scheduled for February 1995 (paragraph 4.4). Also, the licensee satisfactorily performed its cold weather preparation activities.

1.4 ENGINEERING AND TECHNICAL SUPPORT

Performance in this area continued to be good. The licensee's engineering organization satisfactorily supported the operations department in several cases, including operability issues associated with the Unit 1 condenser tube leak investigation and repairs, and an operability assessment for the safety injection pump pressure reducing sleeve locknut, a diesel generator postulated room ventilation failure, and Okonite taped cable splices. Detailed discussions are found in paragraphs 5.1 through 5.3.

2.0 PLANT OPERATIONS

Unit 1

Unit 1 operated at 100% power in the load following mode after restart from the refueling outage, November 2, 1994, until December 3, 1994. On December 3, 1994, the unit was taken off line due to a large circulating water leak in the condenser. The reactor was taken critical on December 16, 1994, at the conclusion of the resulting 13 day forced outage.

Unit 2

During the inspection period, Unit 2 operated up to 100% power in the load following mode until December 2, 1994, when the unit was removed from load following duties due to nearing the end of core life.

2.1 OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors verified that the facility was being operated adequately in conformance with applicable licenses and regulatory requirements. Also, the inspectors reviewed management involvement in routine and special plant activities, to ensure that licensee's controls were effective in achieving safe operation of the facility.

On a sampling basis, the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored control room indications for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station management.

In general, the licensee effectively oversaw and directed safe plant operations. Several operational incidents and issues required coordination between operations, maintenance, and engineering staff, with respect to plant operability. The inspectors had several concerns relating to overtime deviation records. The following items describes significant activities that affected the operations department.

2.2 END OF UNIT 1 REFUELING OUTAGE (B1R06)

On November 2, 1994, at approximately 5:00 a.m., Unit 1 was synchronized to the grid. This ended a 55 day refueling outage. Major items completed during the outage included:

- Cycle 7 core load

- Approximately 900 steam generator tubes plugged

- Steam generators chemically cleaned, and approximately 3600 pounds of iron oxide removed from each steam generator

- The 1B hot leg wide range temperature instrument was repaired, exiting an emergency technical specification issued in August 1994

Overall, the Unit 1 refueling outage was adequately completed; however, due to the extent of the steam generator tube degradation, a mid-cycle outage to inspect the steam generator tubes was scheduled for September 1995. Additionally, during the startup, the licensee experienced mechanical problems associated with the 1A motor driven main feedwater pump (section 2.5). The 1B turbine driven feed pump was placed in service and the startup was continued.

2.3 UNIT 1 CONDENSER TUBE LEAK

During the evening on December 3, 1994, the Unit 1 condensate system experienced a significant chemistry excursion. The licensee initially responded to high alarms in the secondary system in-line chemistry monitors. Subsequently, chemistry samples were taken to analyze and confirm the secondary water quality. The initial results indicated a conductivity of 210 μmhos/cm and sodium concentration of 2500 ppb. (Normal secondary water chemical concentrations are: sodium <.5 ppb, chloride .3 ppb, sulfate 4 ppb, and conductivity .5 μmhos/cm.) The licensee commenced a power reduction, and proceeded to shutdown the plant due to the severity of the secondary water chemistry excursion. On December 4, 1994, Unit 1 was shutdown. On December 5, 1994, Unit 1 was in Mode 4 at approximately 210 degrees F with secondary chemistry of sodium 3900 ppb, chloride 10200 ppb, sulfate 55000 ppb, and conductivity of 488 μmhos/cm. These concentrations were comparable to those found in the river water which Byron uses for the circulating water system.

The licensee was able to determine the source of the secondary chemistry event to be a circulating water leak in the condenser circulating water box. The leak was caused by a small section of condenser deflection grating that broke loose and fell to the bottom of the condenser. The grating damaged two condenser tubes. One tube was only dented, while the other tube suffered a hole of approximately 1 to 2 inches in diameter. The secondary side and steam generator chemistry peaked at 80,000 ppb sulfates, 2500 ppb sodium, 11,000 ppb chlorides, and 760 μmhos/cm conductivity. The secondary side and steam generators were drained and flushed until the chemistry was within acceptable levels for startup. The sulfate ion was the most limiting of the chemicals to clean up. The startup requirement for sulfates was less than 100 ppb.

The licensee's root cause team determined that the grating fell due to weld failure. The damaged grating was only secured by five weld points attached to the vanes of the grating. Four of the welds had failed and the grating broke loose when the last vane holding the grating broke due to fatigue failure. The licensee determined that this piece of grating was inadequately secured in the condenser. A thorough inspection of all gratings was conducted and no other discrepancies were identified. Corrective actions included plugging both damaged condenser tubes. The licensee determined not to stake the damaged tubes, instead proceeded to plug 5 to 6 tubes surrounding each damaged condenser tube. The licensee indicated that the extent of damage to the steam generator tubes, caused by the chemical incursion from the condenser tube leak, if any, could not be evaluated until the mid-cycle outage to perform the steam generator tube inspections. The mid-cycle outage is scheduled for September of 1995.

Byron Unit 1 was restarted after a 13 day forced outage due to the condenser tube leak. The reactor was taken critical and the generator output breakers were closed on December 16, 1994. Due to the level of sulfate chemistry hideout return, the plant was limited to operation less than 30% reactor power. Subsequent to the reactor startup, the sulfate concentration in the steam generators increased to approximately 250 ppb. (To continue in high power operations, the sulfate concentration must be less than 20 ppb.) At the end of this inspection period the licensee was continuing the secondary side steam generator cleanup. The licensee's operations and chemistry organization performed satisfactorily to mitigate the consequences of the condenser tube leak.

2.4 SAFETY INJECTION ACCUMULATOR FILLING EVOLUTION - FAILED TO MEET TECHNICAL SPECIFICATION (TS) REQUIREMENT

On December 8, 1994, during the forced outage on Unit 1 from the condenser tube leak, the licensee identified a TS violation with the safety injection (SI) system in Mode 4. The 1B SI pump administrative out-of-service tagout for Mode 4 was temporarily lifted to make up to the SI accumulators per approved operating procedure BOP SI-5, "Raising SI Accumulator Level with SI Pumps" and in accordance with TS 4.5.3.2. The reactor operator along with the shift control room engineer (SCRE) (senior reactor operator) discussed the TS requirements to have the SI discharge valve closed during the accumulator filling evolution. However, the operators failed to note the TS footnote requirement, operating procedure limitations, procedure actions item 3, which required that the discharge valve be closed and de-energized. The valve was closed, but it was not de-energized. During the shift turnover, the on-coming SCRE identified the discrepancy and the pump was immediately returned to its administrative out-of-service. The licensee initiated a formal root cause determination and will issue a licensee event report (LER).

The inspector reviewed the circumstances of the event, and with the valve closed it appears to have met the intent of the safety function of preventing a cold water addition pressure transient with reactor coolant system temperature below 330 degrees F. However, the potential of a transient still existed without the valve being de-energized. The licensee adequately identified and mitigated the condition initially; however, the inspectors will review the licensee's LER to assess the corrective actions to prevent recurrence. This item will be tracked under the licensee's submitted LER.

2.5 MOTOR DRIVEN MAIN FEEDWATER PUMP DRAIN LINE LEAK AT THE END OF THE UNIT 1 REFUELING OUTAGE

During the startup from the refueling outage on November 2, 1994, the 1A motor driven main feedwater pump was tripped due to a feedwater leak. The leak was from a loose pipe union on the drain line for the pump casing. The drain line isolation valve was opened by the pump pressure and the loose union allowed the pipe to turn and spray water on the floor. The motor control cabinet (MCC) next to the pump was also sprayed and was de-energized as a precaution. This MCC supplies the condenser vacuum pumps and three of the main turbine oil lift pumps. The operating crew tripped the main turbine, which was spinning at 1800 rpm, as the condenser vacuum was decreasing. The licensee started a steam jet air ejector to provide a condenser vacuum and return the main turbine to 1800 rpm because only three of the six turbine bearings would have oil supplied at low rpm. The 1A main feedwater pump was made operable by tightening the union, fastening the valve shut and capping the drain line.

The cause for the pump bowl drain line isolation valve opening under pressure was unknown. This valve model was used only as the main feedwater pump bowl drain line isolation. The other drain valves on the five remaining feedwater pumps have not indicated any problems, and were performing satisfactorily. The licensee planned to return the faulty valve to the vendor for evaluation of the failure. It was noted that this valve, on the 1A main feedwater pump, was a replacement installed during the September 1994 Unit 1 refueling outage. The inspectors concluded that the licensee took quick and proper mitigating actions to prevent additional equipment damage, in particular to the main turbine.

2.6 OVERTIME DEVIATION REVIEW

During this inspection period, about 300 overtime deviation authorization records from August 1 - November 1, 1994, were reviewed to determine the effectiveness of the overtime deviation authorization program. The majority of the records were outage related. The inspectors identified several concerns relating to the adequacy of implementing the overtime deviation authorization program.

Technical Specification (TS) 6.2.2.e requires that the amount of overtime worked by staff members performing safety-related functions shall be limited in accordance with the NRC Policy Statement on working hours (Generic Letter No. 82-12). Generic Letter 82-12 recognizes overtime may be required during extended periods of shutdown for refueling and provides guidelines to be followed. The guideline states that an individual should not be permitted to work more than 16 consecutive hours, or work more than 16 hours in any 24 hour period, nor more than 24 hours in any 48 hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time. These guidelines have been incorporated in BAP 100-7, "Overtime Guidelines for Personnel." Generic Letter 82-12 also states that "very unusual circumstances may arise requiring deviation from the above guidelines."

Furthermore, the licensee's procedure BAP 100-7 required that initial approval of guideline deviations would be made before the deviation occurred. To reinforce the importance of this, the related form, BAP 100-7T1, "Overtime Deviation Authorization," contained a note indicating, "Approval of this authorization indicates that potential for significant reduction in personnel effectiveness has been evaluated." This was then followed by the statement, "INITIAL APPROVAL SHALL BE COMPLETED PRIOR TO DEVIATION," immediately above the signature space. The inspectors identified 29 examples where the initial approval date was after the deviation date and an additional ten examples did not have an initial approval date provided. This is considered a violation of the licensee's procedure and Technical Specifications (50-454/455-94025-01 (DRP)).

Additional concerns were noted during the review. These were:

- Apparent incorrect completion of the number of hours over the guideline, including one case where an individual indicated exceeding the guideline by 24.5 hours on the seventh day and another individual working 34 hours in one day.

- Multiple sheets submitted for the same person on the same day with different hours over the referenced guideline listed. This happened on two consecutive days for the same individual with the same person approving initial authorization on all four sheets on the same day.

- Poor description of the cause for deviation, including 28 examples of volunteering to prevent forced (involuntary) overtime, two examples of no cause for deviation listed, 14 examples of multiple deviation dates listed without adequate explanation of the reason and duration of the deviation, and several cases of refueling outage as the only cause.

In addition to the above items, the inspectors were concerned about the potential for excessive use of overtime and possible detrimental effects towards operation and maintenance activities. In several cases, individuals worked for seven consecutive days twelve hours above the 72 hours in seven days guideline. The inspectors reviewed a sample of known personnel errors from August 1 through November 1, 1994. No errors were identified which correlated to persons who had worked improperly approved excess overtime.

In mid October, 1994, Site Quality Verification (SQV) performed a surveillance on overtime deviation documentation. The surveillance focused on completion of the form when required and the date of initial approval compared to the date of deviation. A finding similar to the above violation was documented. The surveillance also noted a "significant number of high overtime observations," but was apparently not pursued since the amount of overtime was outside the scope of the surveillance. The monthly SQV report used the same phraseology. The station manager issued a letter reiterating the importance of completing the deviation form and gaining initial approval in advance of the overtime worked.

The inspectors concluded that neither the administrative requirements nor the intent of the procedure had been met. Followup of this problem was limited and did not address the number or cause of the deviations that were occurring. The inspectors stated to the licensee that apparently the overtime control program was not receiving proper management oversight. The licensee's management stated that the management had begun to assess individuals requesting overtime and review all requests for overtime deviation. The inspectors confirmed that the problem was not continuing during a period of low activity following the outage.

One violation was identified.

3.0 PLANT SUPPORT (71750)

3.1 CHEMISTRY

A large (approximately 20 gpm) circulating water leak into the Unit 1 condenser occurred. The chemistry department made a recommendation for a plant shutdown due to the projected levels of chemical contamination in the steam generators. The secondary cleanup required frequent sampling and analysis to assess the status and effectiveness of the various methods being used to remove the contaminates. The inspectors concluded that the department's performance and management involvement was timely and provided sufficient guidance for plant operations to cleanup the secondary system.

3.2 HOUSEKEEPING AND PLANT CLEANLINESS

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter. An inspection was conducted for the specific area of foreign material exclusion (paragraph 4.4). Overall, the licensee continued to maintain good housekeeping and plant cleanliness.

3.3 RADIOLOGICAL CONTROLS

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc. and randomly examined radiation protection instrumentation for use, operability, and calibration.

3.4 SECURITY

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that the approved security plan was being implemented. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors verified that checked vital areas were locked and alarmed. The inspectors also observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

No violations or deviations were identified.

4.0 MAINTENANCE/SURVEILLANCE (62703 & 61726)

4.1 MAINTENANCE ACTIVITIES (62703)

Station maintenance activities were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with technical specifications.

The following items were also considered during this review: approvals were obtained prior to initiating the work; functional testing or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed or reviewed:

- 1A Main Feedwater Pump Troubleshooting Pump Bearing Running Hot
- 2A Main Feedwater Pump Troubleshooting Motor Bearing Running Hot
- Source Range Nuclear Instrument Channels N31 and N32 Troubleshooting and Repair
- Unit 1 Reactor Coolant Loop Flow Instrument Venting

4.2 SURVEILLANCE ACTIVITIES (61726)

During the inspection period, the inspectors observed technical specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with technical specifications and procedure requirements and were reviewed, and that any deficiencies identified during the testing were properly resolved.

The inspectors also witnessed portions of the following surveillances:

- 1A Auxiliary Feedwater Pump Monthly
- 1B Auxiliary Feedwater Pump Monthly

- 1B Emergency Diesel Generator Monthly
- 2B Solid State Protection System Bimonthly Continuity Verification
- Cold Weather Protection Yearly Verification

4.3 REACTOR COOLANT LOOP FLOW OSCILLATIONS

On November 13, 1994, approximately two weeks following the Unit 1 restart from the refueling outage, the licensee noted a slight oscillation in the three channels of the Unit 1 "C" loop reactor coolant system (RCS) flow indications. The magnitude of the oscillation was approximately ±2%, peak to peak. On November 14, the inspectors questioned the apparent increase in RCS flow oscillation in loop C. The inspectors observed the maximum RCS flow oscillation to be approximately -2% to +6%, peak to peak. The licensee performed troubleshooting activities and calibration checks on the flow instrumentation. On November 16, 1994, chart recorders were installed at the instrumentation panel to accurately monitor and record the loop flow oscillations. Following the evaluation of the data, the licensee determined that the indicated oscillations were actually coming from the containment differential pressure (D/P) loop flow transmitter/instrument line and not an electronic instrumentation problem.

The licensee investigated potential causes for this oscillation. The investigative actions included, setting up a recorder to monitor reactor coolant pump amps, contacting other utilities for information of similar events, investigating the differential pressure (D/P) change across the "C" steam generator ("C" steam generator had the most tubes plugged), and reviewing past Byron station operating history for similar occurrences. By elimination of all other possible causes, air in the high pressure side of the D/P cells was considered to be the cause of the oscillations. To vent the high side of the loop flow D/P cells required a power reduction to less than 30%. During the condenser tube leak forced outage, the 1C loop flow D/P cell was vented and found to have air in the high pressure side. The other three loop D/P cells were vented and varying amounts of air was found in each cell. Subsequent to the restart and power escalation from the forced outage, no indications of flow oscillations were noted.

In conclusion, the flow oscillation indications was found not to be an actual flow oscillation; therefore, it would not have caused any operational problems. However, the inspector questioned if line venting of the these instruments were normally being performed and if it was proceduralized. The licensee, through its root cause investigation, found that normal maintenance practice in working with these type of instruments would have performed venting. However, it was determined that it was by skill of the craft and was not formally proceduralized. The licensee's review also found that the procedures used to test and repair these D/P cells did not contain a method to vent the cells. The licensee initiated actions to revise these procedures to provide requirements for venting the instrument lines after reactor coolant loops are filled and vented. Overall, the licensee's corrective actions were considered appropriate.

4.4 TEMPORARY INSTRUCTION 2515/125 - FOREIGN MATERIAL CONTROLS (Closed)

The licensee implemented a new procedure BAP 100-22, "Foreign Material Exclusion," Rev 0, dated January 7, 1994. This procedure provides the basic requirements for the foreign material exclusion (FME) program utilized throughout the plant. Other procedures further define requirements affecting certain specialized activities and requiring documentation. These procedures delineate the requirements associated with certain organizational groups (e.g., electrical maintenance, mechanical maintenance, fuel handling, and quality control). Examples of these procedures are: foreign material exclusion from open equipment and process lines; system cleanliness; cobalt exclusion from reactor coolant; fuel handling cleanliness zones and requirements; quality control in-process maintenance cleanliness verification; and station material condition/housekeeping inspection program. The inspector observed that these procedures adequately listed requirements associated with material, parts, and tool accountability, and adequately covered all applicable work activities which would require FME controls.

Although the procedures and work activities observed by the inspectors adequately implemented FME controls, the controls did not prevent all FME problems. The licensee within the last year have identified some FME concerns. These concerns ranged from small tools dropped within equipment that was taken out of service for maintenance, to inspection covers found removed and not timely replaced. All of these concerns were adequately corrected prior to equipment operation, and there were no failures to equipment from inadequate FME controls. The licensee has initiated a trend evaluation of these FME concerns. Although the action to follow up on FME concerns appears proactive, the licensee appears not to have initiated any definitive corrective action to the FME problems; with the exception of reiterating the FME requirements at safety meetings. The licensee's FME trend evaluation and controls for the next refueling outage in February 1995 will be tracked as an inspection follow up item (50-454/455-94025-02 (DRP)).

Overall, the licensee's FME program appeared satisfactory.

4.5 COLD WEATHER PREPARATION (71714)

The surveillance was planned to be started and completed in September; however, the licensee did not start until October. The surveillance was completed by end of November 1994. Several discrepancies were noted by the licensee in performing the surveillance. These discrepancies primarily involved room heaters and fans. Some of the heaters/fans needed minor repairs, but did not impede safe plant operations. The licensee adequately performed the cold weather protection surveillance, although behind their schedule. Overall, the freeze protection for plant equipment required for safe operation was sufficiently implemented.

One inspection follow up item was identified.

5.0 ENGINEERING & TECHNICAL SUPPORT (37551)

The inspectors evaluated the extent to which engineering principles and evaluations were integrated into daily plant activities. This was accomplished by assessing the technical staff involvement in non-routine events, and assigned technical specification surveillance. Further evaluation was conducted, as necessary, by observing technical staff involvement associated with on-going maintenance work and troubleshooting, and reviewing non-conformance investigations and root cause analyses. The engineering organization continued to demonstrate good engineering awareness and initiatives. The following significant engineering activities were reviewed.

5.1 SAFETY INJECTION (SI) PUMP PRESSURE REDUCING SLEEVE LOCKNUT

On October 22, 1994, the licensee performed an operability assessment on the safety injection pumps concerning a Part 21 notification from Westinghouse. The Part 21 notification concerned the potential susceptibility of the SI pump pressure reducing sleeve locknut to intergranular stress corrosion cracking (IGSCC). The notice indicated that the locknuts supplied by Ingersoll-Dresser Pump Company (through Westinghouse) have increased susceptibility to IGSCC due to material and the heat treatment used. Apparently, the combination of the material (416 stainless steel (SS)) and heat treatment process can potentially produce a high material hardness condition that could be highly susceptible to IGSCC in an aqueous environment.

The pressure reducing sleeve locknut is used to retain the pressure reducing sleeve. If the locknut catastrophically fails into fragments, the locknut will not be able to retain the pressure reducing sleeve, which would ultimately lead to a pump seizure.

The notice did not confirm the presence of cracks in the locknuts. The licensee gathered limited industry history on the suspect locknuts. In one case where the SI pump run time was in the excess of 2000 hours, it was found that the locknut was cracked, but the pump was still functional. In other cases no cracks were identified. The licensee further evaluated the functional requirements of the SI pumps for post accident conditions. The licensee indicated that the SI pumps are required to operate for approximately 3 hours during a small break loss of coolant accident in order to fulfill its primary safety function. Other accidents required shorter run times. Additional information gathered by the licensee indicated that the accumulated run times of the SI pumps were less than 2000 hours. The highest run time was on pump 2A with 1100 hours. The three remaining pumps ranged from 450 to 750 hours. The licensee also determined that the SI pump environment, of normal operating temperature of 114 degree F, was significantly less than the 180 degree F at which IGSCC was expected to occur in 416 SS. The licensee intended to replace the lockouts with an improved part for

Unit 2 in February 1995 and for Unit 1 in April and June 1995. Based on the above information, the licensee concluded that the SI pumps were operable.

After reviewing the licensee's operability assessment, the inspectors concluded that it appeared adequate. With the information comparing the licensee and the industry history, it appeared reasonable to conclude that the SI pumps were operable.

5.2 DIESEL GENERATOR OPERABILITY ASSESSMENT DUE TO POSTULATED ROOM VENTILATION FAILURE

On November 10, 1994, the licensee's system engineering department received an operability question from the Braidwood station. The question concerned the location of fire protection and room ventilation relay cabinets associated with the emergency diesel generators. The Carbon Dioxide (CO_2) system components (including the diesel generator ventilation (VD) damper control panels and manual CO_2 pushbuttons) that affect redundant trains of VD are located within the same fire zone contrary to 10 CFR 50 Appendix R section 3G. A single fire in these zones could have the potential to adversely affect both trains of VD such that both diesel generators could be affected (potentially rendering it inoperable while the diesel is running, due to overheating from the lack of room ventilation). The licensee identified the potential condition subsequent to the review of a October 6, 1994, Cooper Nuclear Power Station incident.

The licensee initiated an operability assessment to review the postulated VD failure mechanism. The concerns were associated with the failure of the ventilation system due to a fire or seismic event. The licensee determined that an analysis had been previously performed for a loss of VD during a high energy line break (HELB), and that this analysis assumed that the VD dampers would close because of their proximity to steam from the turbine building during a HELB. The HELB analysis determined that the diesel generators could operate for a period of two hours without VD. Based on this information and the similarity of the loss of VD due to damper isolation from a fire or seismic event, the licensee determined that the diesel generators could operate up to two hours, subsequent to the loss of VD from a fire or seismic event.

The licensee further determined that the fire loading of the area outside the diesel generator rooms was within the one hour fire loading based on the NFPA Fire Protection Handbook. Also, an hourly fire watch was set in place and controls were established to limit transient fire loads outside the diesel generator rooms. With the assumption of the two hour diesel operation without VD, the licensee determined that it was feasible with operator action to restore ventilation within one hour after the postulated one hour fire was extinguished. Utilizing the similar two hour diesel operation and ventilation restoration, the licensee determined that the analysis for seismic operability was also bounded by the HELB analysis. Therefore, the licensee initially determined that the diesel generators were operable. The licensee continued to review the issue, and final resolution of the operability assessment documentation was still pending.

The inspectors questioned the capability of the licensee to restore the ventilation dampers following a seismic event. Specifically, the inspectors questioned how operators would get access to the diesel generator room following a design basis seismic event that would potentially block room access. Although the turbine building was not classified as seismic class 1, the building structure was constructed to withstand a postulated seismic event. Also, it was determined that access to the diesel room could be accomplished through the diesel generator exhaust and intake ventilation room. The inspectors concluded that it was reasonable to assume operability of the diesel generators based on operator actions to restore room ventilation within two hours to promote continued diesel operation. The licensee's operability assessment appeared to be adequate.

5.3 OKONITE TAPED CABLE SPLICES

Braidwood Inspection Report 89018 identified a concern about the environmental qualification of Okonite taped cable splices which were located in junction and pull boxes subject to local submergence. The NRC staff issued a recent Braidwood Safety Evaluation Review (SER) dated September 8, 1994, stating that the licensee's documentation to demonstrate the qualification of Okonite taped splices for submergence was inadequate. Byron has the similar splices throughout the plant, and the licensee initiated an operability assessment on September 15, 1994.

The concern was the environmental qualification (EQ) of the Okonite tape splices under local submergence due to a high energy line break accident. The SER stated that the licensee's tests submitted to show environment qualification under submergence testing were inadequate; the tests did not subject the splices to the entire test sequence and submergence required during the design basis event. However, the licensee considered that the testing was adequate to meet the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The splices which could experience local submergence were those installed in the Unit 1 & 2 containments and steam tunnels. These splices were installed in the following Class 1E circuits: 480 volt AC power, 125 volt DC control, and 120 volt AC control. The licensee stated that the splices of concern were installed in the plant as part of the original design in accordance with accepted design practices and procedures at that time.

The primary point of disagreement involved the basis for submergence qualification. The NRC staff position requires that full submergence of the test specimen during a full EQ testing sequence must be demonstrated. The licensee contended that the basis for submergence qualification was met utilizing the analytical review of type testing of various EQ tests which included partial submergence, and insulation testing under full submergence during a non-EQ test. The licensee's documentation indicated that a total of 29 test specimens having various configurations were exposed to simulated accident conditions. None of the test specimens failed; all maintained their circuit integrity throughout the tests. Based on the testing results, the licensee considered that the Okonite splices will adequately perform the intended safety functions.

The licensee has initiated a clarifying response, scheduled for May 1, 1995, to acquire and submit the documentation necessary to adequately demonstrate the EQ of Okonite taped splices under local submergence conditions. The issue associated with the Okonite splices is considered to be an unresolved item (50-454/455-94025-03(DRP)).

No violations or deviations were identified.

6.0 REPORT REVIEW

During the inspection period, the inspector reviewed the licensee's Monthly Performance Report for the period of August to November 1994. The inspector confirmed that the information provided met the requirements of Technical Specification 6.9.1.8 and Regulatory Guide 1.16.

The inspector also reviewed the licensee's Monthly Plant Status Report for the period of August to November 1994.

No violations or deviations were identified.

7.0 PERSONS CONTACTED

COMMONWEALTH EDISON COMPANY (COMED)

*K. Schwartz, Station Manager
*T. Gierich, Operations Manager
D. St. Clair, Site Engineering Construction Manager
*P. Johnson, Technical Service Superintendent
*E. Campbell, Maintenance Superintendent
*M. Snow, Work Control Superintendent
*D. Brindle, Regulatory Assurance Supervisor
A. Javorik, Technical Staff Supervisor
E. Zittle, Security Administrator
*R. Wegner, Shift Operations Supervisor
P. Donavin, Site Engineering Mod Design Supervisor
M. Rasmussen, Operations Engineer Unit 2
*T. Schuster, Site Quality Verification Director
C. Bontjes, Acting SQV Supervisor
K. Passmore, Station Support & Engineering Supervisor
*P. Enge, NRC Coordinator
*W. Kouba, Long Range Work Control Superintendent
J. Bauer, Executive Assistant
T. Higgins, Support Services Director
*G. Contrady, Site Engineering Construction Programs Lead

*B. Bielasco, Senior Site Quality Verification Inspector

*Denotes those attending the exit interview conducted on December 15, 1994.

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

8.0 DEFINITIONS

8.1 INSPECTION FOLLOWUP ITEMS

Inspection followup 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. An Open Item disclosed during the inspection is discussed in Paragraph 4.4.

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 paragraph 5.3.