U. S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-254/95006(DRP); 50-265/95006(DRP)

FACILITY
Quad Cities Nuclear Power Station, Units 1 and 2

License Nos. DPR-29; DPR-30

LICENSEE
Commonwealth Edison Company
Executive Towers West III
1400 Opus Place, Suite 300
Downers Grove, IL 60515

DATES
July 23 through September 1, 1995

INSPECTORS
C. Miller, Senior Resident Inspector
K. Walton, Resident Inspector
P. Prescott, Resident Inspector
R. Mendez, Reactor Inspector, RIII
R. Ganser, Illinois Department of Nuclear Safety

APPROVED BY

Pat Hiland

Pat Hiland, Chief
Reactor Projects Branch 1

10/4/95
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.

EXECUTIVE SUMMARY

Operations

- A Unit 2 reactor trip resulted from turbine electro-hydraulic control (EHC) pressure regulator response problems (section 1.2). Operator response was good. Engineering discrepancies will be followed as IFI 50-254/265-95006-01.

- Operators failed to trip the reactor after exceeding a pre-established condition. The licensee identified that the root cause was due to a pre-job brief not assigning individuals responsibilities and weaknesses in communications (section 1.3).

- Operators continued to experience problems with unexpected increases in recirculation pump speed control. One event resulted in Unit 1 briefly exceeding the licensed thermal power limit (section 1.6).

- Operators and operations management demonstrated weak procedure adherence and less than conservative decision making in response to a valve failure on the residual heat removal service water (RHRSW) system (section 1.7).

Maintenance and Surveillance

- EHC tuning errors caused several turbine bypass valve oscillation problems during Unit 2 startup (section 4.1).

- The licensee identified that four low condenser vacuum pressure switches were outside the technical specification tolerance. The licensee had replaced the switches due to the switches being prone to drift but had failed to monitor switch performance on an adequate frequency (section 2.3).

- Failure of a control room emergency ventilation surveillance was due to freon leaking from a brazed joint in the refrigerant compressor system (section 1.4). Operators had not previously checked refrigerant level on a routine basis.

- Power operated relief valve (PORV) leakage caused a Unit 2 shutdown (section 1.5).

- The licensee identified incorrect bolting installed on numerous control rod drive (CRD) system directional control valves (section 2.4).

Engineering and Technical Support

- The licensee partially incorporated recommendations of a vendor notice during maintenance without adequate review. The resultant oscillations of turbine bypass valves resulted in operators shutting down Unit 2 (section 3.1).

- Engineering investigation of the cause of the "A" feedwater regulating valve lockup condition was thorough. The condition was due to low hydraulic pressure with insufficient margin to overcome actuator friction (section 3.3).

Plant Support

- Plant support efforts remained good. Efforts to improve turbine rollup doors and badge issuance have resulted in reduced dose and improved efficiencies (section 4.0).

Safe Assessment/Quality Verification

- The inspectors identified numerous overdue level 3 PIF investigations. Some of the overdue PIFs were directly related to ongoing plant activities of a similar nature (section 5.1).

- The inspectors noted problems with several work activities which resulted from poor product or service quality and inadequate licensee oversight and review (section 5.2).

INSPECTION DETAILS

1.0 OPERATIONS:

Inspectors used NRC Inspection Procedure 71707 to evaluate plant operations. Unit 1 continued operations at or near full power. Unit 2 was in startup testing following the refueling outage. One reactor trip resulted from poor EHC system response during testing. Other equipment problems resulted in three additional Unit 2 reactor shutdowns.

1.1 Follow-up of Events (93702)

During this inspection period, the licensee experienced several events, some of which required notification of the NRC via the ENS pursuant to 10 CFR 50.72. The specific events were as follows:

July 26	Operators manually shut down Unit 2 due to failure of turbine bypass valve (TBV) control circuit.
July 26	ENS call. Technicians found all four Unit 2 condenser vacuum pressure switches were out of technical specification tolerance.
July 27	Unit 2 startup after repairs to TBV circuits and replacement of condenser vacuum pressure switches.
July 29	Operators manually shut down Unit 2 due to failure of turbine bypass valve control circuit.
August 6	High reactor water level transient during feedwater regulating valve testing.
August 12	ENS call. Safety related control room ventilation system compressor failed to operate.
August 12	Unit 2 main turbine taken off line to repair EHC system leak
August 13	Operators shut down Unit 2 to address power operated relief valve (PORV) seat leakage.
August 17	Unit 2 made critical after PORV seat leakage addressed and EHC leak repaired.
August 18	ENS call. Unit 1 exceeded licensed thermal power due to unexpected increase in recirculation pump speed.
August 25	ENS call. Unit 2 automatic reactor trip from high flux during testing.

1.2 Automatic Reactor Trip

On August 25 the Unit 2 reactor automatically tripped from about 60 percent power during turbine electro-hydraulic control (EHC) testing. The test was designed to evaluate the dynamic response of the EHC pressure control system, which had been repaired during the refuel outage. The "A" pressure regulator was intentionally failed, and the "B" pressure regulator was expected to pick up control. The reactor tripped on average power range monitor (APRM) high flux due to partial rapid closure of the turbine control valves. All automatic functions occurred as expected. The operators stabilized plant parameters, and took the unit to a cold shutdown condition to determine and correct the root cause of the trip. The operating crew performed well and handled the event simultaneous with another event involving an injured person in the 2B residual heat removal (RHR) room.

Engineers determined that the 5 psig pressure offset of the B pressure regulator from the A regulator, and response settings of the pressure regulator notch filter cards were probable causes for the turbine control valve response which led to the trip. Engineers had established the settings of the EHC system during the refueling outage and subsequent startup based on information from General Electric engineers and GE SIL 589 "Pressure Regulator Tuning." The inspectors will follow the corrective action to the engineering discrepancy as IFI 50-254/265-95006-01.

1.3 High Reactor Water Level During Testing

The licensee identified that operators failed to trip Unit 2 when a pre-established parameter was exceeded during testing. A pre-test brief did not establish roles and responsibilities. Communications weaknesses during the event contributed to operators failing to trip the reactor.

On August 6, operators were testing the "A" feedwater regulating valve (FWRV) by initiating reactor vessel water level deviations. Operators received a Feedwater Actuator Trouble Alarm in the control room indicating that the "A" FWRV locked-up in an open position. Operators unsuccessfully attempted to clear the condition. Operators did not trip Unit 2 when reactor vessel water level exceeded 44 inches. Water level increased to about 49 inches during the test before operators isolated the "A" FWRV and placed the "B" FWRV in service. Reactor vessel water level returned to the normal level of 30 inches.

Prior to testing, operators discussed test abort and reactor trip criteria if reactor vessel water level deviated outside expected values. The shift engineer and unit supervisor determined that Unit 2 would be manually tripped should water level exceed 44 inches. The operators believed that if reactor vessel water level exceeded 44 inches, a decision to trip the unit would be made. No operator was designated to trip the reactor. During the event, no order was given to trip the reactor, nor did operators state that the reactor should be tripped.

The main turbine and feedwater pump turbines were designed to trip when indicated vessel water level exceeded 48 inches on 2 out of 2 channels. Only one of the two channels tripped, which does not produce a trip signal. Instrument maintenance technicians checked the calibration of both trip channels and found both were within acceptable tolerances.

The licensee assigned a Level 2 investigation to this event and suspended all testing pending investigation completion. Licensee management removed licensed operators who performed the test from shift responsibilities until corrective actions were completed. Managers also discussed the expectations of meeting trip and abort criteria with all active licensed individuals. All shifts received additional training prior to assuming shift responsibilities. Operations management revised pre-evolution briefing criteria to include individual responsibilities. The licensees' investigation determined that the pre-job brief did not designate specific roles and responsibilities prior to testing, and that overall communications during the event were poor.

1.4 Failure of Control Room Ventilation System

On August 12 operations performed Surveillance Test QCOS 5750-2, "Control Room Emergency Filtration System Monthly Test" and identified that the refrigerant cooling unit did not operate. This rendered the control room emergency ventilation system inoperable.

The licensee identified a "pin-hole" leak from a brazed joint which caused the loss of freon from the system. Mechanical maintenance repaired the leak, as well as other mechanical joint leaks and packing leaks. The monthly surveillance test was completed successfully on August 16. The licensee had not determined the cause for the pin-hole leak.

The inspectors noted the licensee had not routinely checked refrigerant level prior to August 12. The inspectors questioned the system engineer and operators who indicated a procedure change was being considered for routine operator checks of refrigerant level. Operators performed operability considerations and reporting for the equipment failure properly.

1.5 Shutdown Due to Power Operated Relief Valve (PORV) Leakage and EHC Leaks

The licensee removed Unit 2 from service to repair an electro-hydraulic control (EHC) system leak and to address PORV seat leakage.

On August 12 operators identified that 2 inches of oil had been lost from the EHC system reservoir over about a 6-hour period. The operators identified a leak from a plug on the No. 6 combined intercept valve (CIV) shut off valve. On August 13 operators shut down the reactor and maintenance technicians repaired the EHC leak. The PORV leakage is further discussed in section 3.2.

1.6 Licensed Thermal Power Limit Exceeded

On August 18 operators identified that the "A" reactor recirculation pump speed controller increased from 95.5 to 100 percent speed. Operators reduced pump speed using the controller. The average power range monitors (APRMs) indicated a power increase to about 102 percent. Nuclear engineers, present in the control room for Unit 2 startup, determined that no core thermal limits were exceeded. The licensee found that core power could have exceeded 102 percent power for less than 10 seconds but that 8-hour averaged core thermal power would not have exceeded technical specification limits. The licensee made a voluntary notification to the NRC. A later test of feedwater flow nozzle calibrations indicated that reactor power for the event may not have exceeded 102 percent.

As a preventive measure, the licensee locked both units' recirculation pump motor generator scoop tubes, and initiated an investigation team. The licensee team concluded that the most probable cause for the recirculation pump runup was a failure of rack mounted speed controller components. The licensee continued troubleshooting this problem and others which have lingered on the reactor recirculation system.

1.7 Missed Opportunity to Enforce Expectations

The inspectors noted a missed opportunity for operations management to enforce procedure adherence and conservative decision making expectations. On August 28 the inspector questioned the Unit 2 nuclear station operator (NSO) about a RHR valve failure that occurred earlier in the shift. The operator stated that while positioning the valve to the specified open indication, the valve indicated that it stopped travel at about 62 percent (the procedure stated "at least 65 percent"). The NSO announced to the unit supervisor (US) that the position indication had hung up and the control switch was held open for several more seconds then the pump was started [It was believed this would move the valve farther open to the position specified to prevent relief valve lift on pump start]. The operator then started the RHRSW pump and throttled the valve closed to establish the required system pressure. At about 52 percent open, the valve travel stopped, and the valve motor's supply breaker tripped. The valve would not move after thermal overloads were reset, and the valve was placed out of service (OOS) for investigation and repair. The licensee determined the cause of the breaker trip to be mechanical binding and galling of the valve disc on the valve trim.

The inspectors discussed with the NSO, US, and Shift Engineer, the apparent failure to believe instrumentation and take a conservative approach by halting the activity when there was an initial indication that the valve travel had ceased. The Shift Operating Supervisor reinforced station management's expectation of procedure adherence. Safety consequences as a result of this specific deviation were minimal since the RHRSW heat exchanger was not required at the time. However, the inspectors noted that similar actions could lead to premature system degradation by workers failure to identify and correct causes of poorly operating equipment.

2.0 MAINTENANCE:

Inspectors used NRC Inspection Procedures 62703 and 61726 to evaluate maintenance and testing activities. The inspectors noted work package, scheduling and coordination, and rework problems. Condenser vacuum pressure switches continued to drift after maintenance.

2.1 Rework

The licensee identified a leak on the No. 6 combined intermediate valve (CIV) shut off valve. The shutoff assembly was replaced, and all other assemblies were checked and found tight. However, the system engineer identified on the leaking shutoff valve that a bolt was of a different size and the gasket was made of a different material than the other assemblies. The licensee ordered the assemblies from a vendor that may have rebuilt one of the assemblies with incorrect parts.

The licensee installed ten of these assemblies during the outage; four on the main stop valves and six on the CIVs. The assemblies were pressurized weeks before startup when the EHC system was placed in service; no leaks were identified. The shutoff valves installed in Unit 1 during the last outage have performed without problems.

The licensee identified an additional rework issue on a drywell cooler fan which operated in reverse direction. The licensee had rewired the fan motor during the refuel outage but workers did not check fan motor rotation. Workers later found improper rotation based on air flow. Maintenance workers rewired the fan motor, and proper air flow was verified.

2.2 Standby Gas Treatment System (SBGTS)

On August 21 the licensee took the 1/2 "A" train of the SBGTS out of service (OOS) for an extended maintenance interval. The system outage window placed both units in a seven day limiting condition for operation (LCO). The goal set by Station Management was to complete on-line maintenance in half the time allotted by technical specifications (TS). The work was completed within the TS time requirement; however, the inspectors noted a number of deficiencies in the licensee's process for work planning and coordination. The inspectors considered that many of these process weaknesses also pertained to the licensee's performance in conducting work activities on other safety significant systems.

The inspectors observed workers lubricating the SBGTS 7504A Limitorque operator and noted the work package did not specify the lubricant. The workers stated the job foreman was called to get the specification, then the workers proceeded to retrieve the lubricant and grease the valve. The workers then checked off the correct type of lubricant in the work package. This appeared to be a deficiency in work package preparation, and the inspectors followed up by asking the work analyst supervisor why the work package did not specify the required lubricant prior to work beginning. The work foreman's review of the package also failed to specify the lubrication type as required. The inspectors located the completed work package in QA review, and found the feedback form without comment by the workers regarding the missing lube specification. The inspectors concluded that the work package planning process was deficient and a missed opportunity for the foreman and workers to use lessons learned to improve the work process.

The inspector also reviewed a "Risk Evaluation" sheet used to evaluate plant conditions for work on the standby gas treatment system, and noted deficiencies which indicated a lack of attention to administrative detail.

The backup system engineer and plant maintenance workers performed a visual inspection of the standby gas treatment system. The OOS tagout had already been lifted from the system. One worker questioned if removal of inspection covers would breech secondary containment. The system engineer recognized that this would constitute a breach, so a problem identification form (PIF) (95-2270) was generated to identify that this portion of the inspection should only be done with the OOS in place. This was a good observation on the part of the worker but indicated a weakness in pre-planning and coordinating activities.

2.3 Pressure Switches Out of Calibration Limits

The licensees' corrective actions to address Barksdale pressure switch drift problems were inadequate.

On July 26 with Unit 2 in the Shutdown mode, maintenance technicians identified that all four low condenser vacuum pressure switches were outside of technical specification tolerance. Technical specifications (TS) required the switches to actuate at less than 21 inches of vacuum in all modes of operation except Shutdown mode. The pressure switches as-found trip settings were between 0.45 and 0.1 inches of vacuum greater than TS limit. The licensee reported the condition to the NRC. The licensee replaced the switches with identical models, raised the switch setpoints to ensure a greater margin from the TS limits, and increased the frequency of calibration of the switches.

The licensee had replaced these switches due to erratic performance. On April 27 the licensee calibrated all four switches to 21.5 ± 0.3 inches of vacuum. The switches were Barksdale model B1T-H18SS which were purchased as non-safety equipment and then dedicated as safety related components by the licensee. The switches had experienced setpoint drift between instrument calibrations. At times, the drift was outside the error band (± 0.5 psig) but within TS limits even for a newly replaced switch. The inspectors noted that engineers trended these switches but failed to make adequate recommendations for performance monitoring and switch replacement.

2.4 Incorrect Studs Used For CRD System

The licensee identified that replacement studs used for CRD directional control valve repairs were incorrect. The valves were considered safety related due to primary pressure boundary, but the bolts were not ordered as such. The licensee wrote PIF 59-2307 to address the root cause of the issue, and replaced the bolting in an expeditious manner. Engineering and Operations properly considered operability concerns.

3.0 ENGINEERING AND TECHNICAL SUPPORT:

Inspectors used NRC Inspection Procedure 37551 to evaluate the engineering area. Engineering efforts were adequate. The inspectors noted weaknesses in oversight of contractor work, poor follow up and review of data acquisition system events and temporary alterations, and weak review of control rod drive (CRD) malfunctions. Engineering provided good support of several issues such as PORV leakage and feedwater regulating valve lockup.

3.1 Tuning of Electro-Hydraulic Control (EHC) System

Tuning discrepancies in the EHC system caused several problems with turbine bypass valve (TBV) oscillations. The oscillations started small and diverged to where TBVs rapidly cycled open and closed many times until operators took manual control. Small reactor power level and pressure oscillations resulted. The inspectors review of the cause of the cycling identified weaknesses in engineering response to vendor information, outage maintenance, and EHC work procedures. Tuning of control systems was authorized by the work control process. However, the licensee determined that the changes made to the system did not require engineering review. The adjustments made to EHC system resulted in the need to shut down Unit 2 on two separate occasions.

On July 25, with Unit 2 reactor pressure at 470 psig, operators observed that TBVs commenced to cycle open then closed with increasing frequency. Operators stopped the TBV oscillations by manually controlling steam pressure from the turbine control panel. Maintenance workers found that one of two EHC pressure control cards were defective and replaced both cards. In addition, time constants which were changed during the outage, were returned to their original pre-outage potentiometer settings. However, the output voltages on the new cards for the original potentiometer settings were not the same. Believing the problem was fixed, operations made Unit 2 critical on July 27. On July 28, with Unit 2 at 920 psig, operators again noted that TBVs started to cycle with divergent oscillations. Operations shut down Unit 2 again on July 29 to correct EHC system instabilities.

The licensee formed two teams to investigate the event. The licensee identified that this event was caused by partial implementation of General Electric (GE) Service Information Letter (SIL) 589, "Pressure Regulator Training." The SIL recommended changing the EHC pressure regulator time constants. Engineering contracted with General Electric representatives to assist in Unit 2 outage EHC tuning. Based on GE recommendation, the licensee partially implemented the EHC changes without installing a steam line resonance compensator (SLRC) which was also recommended by the SIL. However, without the SLRC installed, the changes introduced instabilities in the pressure regulator portion of the EHC circuit. Other engineering weaknesses involved with the EHC modifications involved insufficient review and implementation procedures which eventually led to the Unit 2 reactor trip mentioned previously.

The inspectors identified procedure weaknesses in the setting of the control room pressure set indication. The procedure problem was exacerbated because the licensee had not developed the EHC refueling outage work request into a formal procedure.

The licensee was addressing EHC weaknesses on PIF 95-2095. The PIF closeout was due September 8 but was not completed on September 21 when the inspectors reviewed the actions.

3.2 Power Operated Relief Valve (PORV) Leakage

Following installation of four PORVs on Unit 2, operators observed indication of leakage past all four valves.

During Unit 2 startup the licensee identified that all four PORVs had high discharge pipe temperatures indicating leakage past the seats. The licensee cycled all four PORVs, and determined that one PORV reseated properly, while seat leakage from the other three PORVs worsened. PORV "E" had the highest seat leakage at between 100 to 250 lbm/hr. The licensee reviewed the data, determined that the leak rate was unacceptable, and removed Unit 2 from service to address the cause of seat leakage.

Technicians disassembled the relief valve's discharge pipe elbows and examined around the seats of the "B" and "E" PORVs. The inspection revealed indications of steam leakage from the main seat on both PORVs, and indication of steam leakage from the "B" pilot seat. There was no indication of seat damage from the steam leak. The licensee believed the most probable cause for leakage to be thermal growth of the discharge piping. The growth allowed piping to contact other structures which may have created a mechanism for seat distortion. The licensee removed a portion of an abandoned angle iron near the discharge piping of the "E" valve. The licensee attributed the seat leakage for "B" and "C" PORVs to insufficient lift time which prevented the valve seat from reaching thermal equilibrium. The licensee planned to test a spare PORV at a later date to evaluate the effects of thermal gradients on the valves' ability to seat tightly.

In addition, the licensee moved the PORV discharge pipe temperature sensing devices farther away from the PORV exhaust port. During the subsequent restart of Unit 2, the PORV downstream temperatures indicated minimal leakage past the PORV seats.

3.3 Feedwater Regulating Valve (FWRV) Locked Up

As discussed in Section 1.3, operators were unable to clear the lockup condition on the "A" FWRV during testing. Engineering assembled a team and with assistance from vendors, investigated the cause of the valve to lockup and the failure of operators to clear the lockup condition.

The investigation team identified minor galling of a mechanical coupling between the "A" FWRV stem and actuator. This, coupled with low hydraulic pressure, (about 1500 psig) caused the valve to lockup and prevented operators from clearing the condition from the control room. The team determined that there was insufficient hydraulic pressure to overcome the friction of the galled coupling. To correct the condition, engineering increased the clearance of the coupling and raised the hydraulic pressure (1850 psig).

The inspectors noted that the team's thoroughness and questioning attitude proved a vendor calculation to be in error and identified the source of the lockup condition. However, the inspectors believed the original modification was weak since engineering established a FWRV hydraulic pressure with insufficient margin to overcome actuator friction.

3.4 Data Acquisition System Initiated Transients

A data acquisition system (DAS) installation appeared to cause an inadvertent reactor power increase and indicated reactor vessel level fluctuations.

The licensee installed a DAS unit on July 19 to monitor and collect baseline data for redundant channels of reactor vessel level and pressure, core flow, steam flow, and APRM flux. These signals which normally feed the instrumentation and control circuits would also be fed through the DAS unit. The APRM flux was the only safety related parameter being monitored. On July 20, during a Unit 2 startup, the NSO noted an unexpected increasing trend on two intermediate range monitors (IRMs). Although the A and B recirculation pumps were in manual, the NSO noticed that the speed of the B pump had increased from about 32 percent to 60 percent, while reactor power increased from 1.9 percent to 2.7 percent. The unit supervisor directed the NSO to adjust the pump speed so that a zero demand signal would be present. The speed of the B pump was reduced to 32 percent and the scoop tubes were locked out. Six hours later, the NSO observed a step change of eight inches in reactor water level. The licensee then disconnected the DAS unit, and the spurious signals stopped.

The inspectors were concerned that the licensee had not adequately tested the DAS unit to determine all the failure modes. Although a 50.59 evaluation was performed, no comprehensive tests were performed to determine whether the DAS unit was actually non-intrusive as assumed by the licensee. In addition, although most of the signals being monitored were non-safety related, the potential of DAS unit to introduce errors or bias the instrumentation signals were not adequately considered. The reactor water level and reactor recirculation signals affected had the potential to significantly affect reactor operation.

The licensee wrote PIFs number 2072 and 2073 to investigate the root cause. These PIFs were scheduled to be closed on September 1; however, the PIFs were still open on September 8 even though other temporary acquisition unit modifications were being installed. The licensee found two apparent causes for the increase in the recirculation pump speed.

The first was the physical inability to completely shield all the input signals. The cables carrying the input signals were shielded throughout the entire run except at the input to the DAS unit which is a 100 point ribbon cable. The electromagnetic interference caused by the inputs could have resulted in feed-back to the speed control circuits.

The other probable cause was the relatively high ac voltage riding on one of the dc signals. The licensee measured voltage as high as 1.7 volts ac riding on the relatively low dc signals which ranged from about 10 to 50 millivolts dc. Engineering was weak in evaluating this problem since it was discovered before the recirculation pump speed event that occurred on July 20. The licensee contacted the manufacturer of the DAS unit and found that the DAS unit cannot adequately filter ac noise where the ac voltage is more than 0.5 times the magnitude of the dc signal.

The inspectors found that a different problem with the DAS had occurred previously. On December 13, 1994, testing personnel found that the reactor low water analog trip associated with the reactor protection system (RPS) scram setpoint was apparently reading out-of-tolerance. Testing personnel found that the DAS unit was affecting the trip set point. The licensee had installed a DAS unit to monitor the response of Rosemount transmitters, associated with reactor water level, to address a General Electric (GE) service information letter (SIL). This DAS had been installed under a temporary modification and a 50.59 evaluation was performed. However, no post installation testing was performed because the licensee believed that the DAS unit would not affect the trip function. After the change in reactor water level was identified, the licensee performed additional troubleshooting and found that with the DAS turned on, the high internal impedance did not cause the setpoint to change. However, when the DAS was turned off the output signal was feeding back through the DAS and caused the trip setpoint to increase. The DAS was reinstalled with instructions and warnings to prevent the DAS from being turned off. However, the licensee did not consider the loss of the 120V ac supply or consider compensatory measures in the event the voltage supply to the DAS unit was lost for any reason.

The inspectors considered the licensee's lack of adequate control of temporary alterations a weakness.

- The licensee had not performed adequate testing to determine the potential for affecting or biasing the instrument signals for indication and control. Preliminary testing would have detected the changes in input impedance to the DAS unit.

- Possible loss of voltage to the DAS units in combination with the effects on redundant channels was not considered.

- Although the licensee was aware of the ac noise present on the dc lines, no further investigation or testing was performed to determine if any adverse effects on the dc signals would occur.

- Although the signals being monitored were non-safety related, the potential of DAS unit to introduce errors or bias the instrumentation signals was not adequately considered.

- Licensee follow up on events in December and July did not identify or correct potential problems for hookup of similar equipment. The inspectors continued to evaluate licensee temporary modification installation, and reviewed the generic implications of these events to other nuclear sites.

3.5 Control Rod Drive Malfunction

During the Unit 2 startup on September 1 the inspectors identified a concern with the licensee's approach to repairs on a malfunctioning control rod drive. Several factors led to the licensee's decision to restart the reactor with an inoperable control rod which could not be repaired until a unit shutdown at a later date. No technical specifications or station procedures were violated as a result of the decision.

Operators experienced significant difficulty while exercising control rods on Unit 2 prior to reactor startup. This was mostly attributed to gasses out of solution in the CRD system, although the problem appeared to be worse than usually experienced prior to startup. Operators exercised and vented individual control rod drives in order to resolve most of the problems. Control Rod K-7, however, would not move with this method even after changing out directional control valves which were suspected of leaking. System engineering identified potential problems with CRD seals and O-rings, which could have been the cause of the failure to move, but the system engineers expected that plant heatup would resolve the problem.

Management decided to start the reactor with the control rod inoperable. When the plant was heated up and pressurized the rod still would not move and was put on the forced outage work list.

The inspectors noted these problems with the licensee's approach:

- The decision not to replace the control rod drive was based on the fact the CRD repair cart needed for the replacement had not been repaired. This cart had been damaged during earlier CRD repairs on Unit 2 and was not fixed. The Unit 1 cart was not available because parts from that cart had been scavenged to fix the Unit 2 cart earlier.

- Significant venting and exercising of the rod failed to correct the problem, making gas intrusion an unlikely cause of the problem.

- Initially, operators and engineers had not accounted for the increased reactivity addition rate caused by adjustment of drive flow on Rod K-7. After the inspector expressed concern with the drive speed, the licensee took proper action to insert the rod and declare it inoperable prior to reactor startup.

The inspectors will continue to follow the licensee's progress in troubleshooting and correcting the problem on Rod K-7 and on the CRD repair cart.

4.0 PLANT SUPPORT:

Inspectors used NRC Inspection Procedures 71750 and 92904 to evaluate Plant Support activities. Plant support activities remained good. Modifications to reduce dose and improve efficiency included a chain link turbine roll-up door and hand scanners installed to replace the badge issue function.

5.0 QUALITY:

Inspectors used NRC Inspection Procedure 40500 to evaluate the Quality function. The inspectors found self assessment to be adequate during the period, with improvement needed in corrective actions and vendor quality review.

5.1 Corrective Actions

In reviewing overdue corrective actions, the inspectors noted that the number of Level 3 PIFs with overdue corrective action had more than tripled since October 1994 (84 in August 1995). The total number of overdue Level 4 PIFs was 195 as of August 1995. The inspectors noted that some of these corrective actions were previously identified by the inspectors and licensee as important to reduce further events.

5.2 Poor Product and Service Quality

The inspectors noted problems with several Unit 2 refueling outage jobs which resulted from poor product or service quality combined with inadequate licensee review and oversight. Problem components included the RHRSW heat exchanger outlet valve 2-1001-5B, Unit 2 EHC parts and engineering support, the Unit 2 feedwater regulating valve modification, the Unit 2 main condenser vacuum pressure switches, and the Unit 2, No. 6 combined intermediate valve shut off valve.

- The RHRSW 5B valve failed for the second time since installation during the Unit 2 refueling outage. Failures were caused by poor anti-rotation device staking on the valve stem, and improper clearance between the valve disc and valve trim. Following the second failure (see section 1.7) the licensee pulled two other similar Anchor Darling Model DT 928 valves from stock, and found similar clearance problems.

  The 5B valve regulates flow of river water for cooling in the RHR heat exchanger. Very tight clearances between the valve disc and trim could lead to binding with silt in the poor quality water.

Prior to the failure neither the licensee or vendor had specified or checked for acceptable disc to trim clearance values. The licensee was evaluating this failure in PIF 95-2300 and considering notification of other affected utilities in accordance with 10 CFR Part 21.

- Poor engineering support and setpoint control resulted during the installation and tuning of EHC components during the Unit 2 outage and subsequent startup (see section 4.1).

- Poor setup of the 2A FWRV caused the valve to lock up during operation, resulting in excessive reactor vessel water level (see section 4.3). Later, maintenance was required on the 2B FWRV due to a steam leak, and that effort was further stalled because improperly sized packing was delivered for packing the valve.

- The Barksdale main condenser vacuum pressure switches which the licensee purchased as non-safety, then dedicated as safety related, have a poor operating history (see section 2.3).

- The No. 6 CIV was apparently assembled with an incorrect gasket and bolt (see section 2.1).

The inspectors will continue to evaluate licensee corrective action and notifications for these conditions which affect maintenance quality.

6.0 EXIT INTERVIEW

The inspector met with the license representatives denoted below during the inspection period and at the conclusion of the inspection on September 1, 1995. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

The following management representatives attended the exit meeting conducted on September 1, 1995, along with others.

ComEd

Bill Pearce, Station Manager
Warren Lipscomb, Site Vice President's Staff
Jack Purkis, Work Control Superintendent
Bob Svaleson, Shift Operations Supervisor
Frank Tsakeres, Rad Chem Superintendent
Mike Wayl[illegible], Maintenance Superintendent
Dennis Winchester, Site QV Director