U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-254/94017(DRP); 50-265/94017(DRP)

Docket Nos. 50-254; 50-265 License Nos. DPR-29; DPR-30

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

Facility Name: Quad Cities Nuclear Power Station, Units 1 and 2

Inspection At: Quad Cities Site, Cordova, Illinois

Inspection Conducted: July 29 through September 30, 1994

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Reactor Projects Section 1B

Inspection Summary

Inspection from July 29 through September 30, 1994, (Report Nos. 50-254/94017(DRP); 50-265/94017(DRP))
Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of followup of events; operational safety verification; monthly maintenance observation; monthly surveillance observation; engineering and technical support; regional request; and licensee action on previously identified items.

Results: An executive summary follows.

EXECUTIVE SUMMARY

Overview

The inspection period included a broad range of activities including completion of and startup from Unit 1 refueling outage, and Unit 2 power operation and startup from a reactor trip. Although overall performance was acceptable, the inspection results identified problems in three broad categories: personnel errors and procedural compliance, material condition, and corrective action.

Personnel Errors and Procedural Compliance

- Four procedural errors listed below were examples of an apparent violation.
  - A plug was inserted in a hydraulic control unit scram solenoid pilot valve vent during maintenance. This was not in accordance with the maintenance procedure (section 2.a).
  - A maintenance technician and foreman failed to satisfactorily perform a visual inspection required by a maintenance procedure, leaving a control rod unable to trip (section 2.a.).
  - A system engineer failed to ensure a rod worth minimizer was in the position required by the procedure during control rod scram time testing (section 2.c.).
  - A system engineer directed scram time testing on the wrong control rod (section 2.b.).
- Procedure work-arounds and lack of self-check were identified as continued weaknesses when operators mistakenly isolated cooling water to the 2B recirculation motor generator lube oil cooler (section 2.d.).
- A reactor feed pump was started with its discharge valve closed due to the operator not verifying a prerequisite step (section 2.e.).

Material Condition

- Control Room Emergency Ventilation system had degraded service water flow to its compressors due to a clogged filter. A deficient flow meter resulted in operators misdiagnosing the problem (section 3.a.).
- Recently instituted uses of predictive maintenance led to early detection of bearing failure in the 2C RHRSW pump. However, no receipt inspection or instructions in the work package verified new shaft tolerances (section 3.b.).
- A failed speed control circuit resistor resulted in tripping of the 2A recirculation pump (section 3.d.).

Corrective Actions

- The licensee did not take appropriate corrective action for scram solenoid pilot valve (SSPV) failures in light of previous industry notifications. This was considered an example of an apparent violation (section 4.a.).

- A control rod scrammed unexpectedly during surveillance testing due to degradation of a scram solenoid pilot valve diaphragm (section 5.a.).

- The licensee continued a trend of poor oversight of work affecting limiting condition for operation times. Engineering support was weak, and operations failed to track the safe shutdown makeup pump until two-thirds of the way through the limiting condition for operation period (section 4.d.).

Operations

- A non-cited violation was issued for failure to implement fire watches (section 4.c).

- The licensee did not perform a timely operability review for scram solenoid pilot valve (SSPV) failures in light of previous industry notifications (section 4.a.).

- The approach to criticality and startup of both units was conservative with good management oversight provided. Some equipment problems were evident (section 6.a.).

- A reactor scram of Unit 2 was attributed to inherent vibration of high steam flow detector sensing lines which were exacerbated by a mechanical vibration from workers contacting the sensing lines with equipment (section 6.b.).

- Operator response to the loss of the 2A recirculation pump was good (section 3.d.).

- Licensee response to a missing piece of feedwater probe was thorough (section 6.c.).

Maintenance and Surveillance

- Failure to follow maintenance procedures led to a control rod being unable to scram due to a plug left in a solenoid valve vent port (section 2.a.).

- Failure to perform a proper post maintenance test following maintenance affecting a SSPV was an example of an apparent violation (section 2.a.)

- Unit 1 high pressure coolant injection flow controller was improperly programmed and was not detected by quality control inspector review.

The improper programming did not effect the operability of the system (section 7.a.).

- Once a vendor manual error was identified that concerned SMB-2 motor operated valves, good corrective actions were taken. However, previous maintenance process errors led to the problem being overlooked (section 7.b.).

Engineering and Technical Support

- Engineering review of CRD system operability and corrective actions following a plug left in a scram pilot solenoid valve were weak (section 4.b.).

- Engineering involvement in control rod scram pilot solenoid valve problems was weak (section 4.a.).

- Engineering failed to identify an operability concern with operations of the core spray system (section 9.a.).

- Engineering review of a Service Information Letter for feedwater flow probes was weak (section 4.d.).

1. Overview

The inspection covered a broad range of activities as Unit 1 started the period shut down for refueling outage Q1R13, then entered startup and power operation for the remainder of the period. Unit 2 was in power operations the majority of the period with a short outage following a reactor trip due to a spurious main steam line flow detector signal. Although overall performance was acceptable, the inspection identified problems in three basic categories: personnel errors and procedure compliance, material condition, and corrective actions. These areas are discussed below, followed by findings in other areas covered by the inspection.

2. Personnel Errors and Procedure Compliance

The inspectors observed good operator control during many of the startup and shutdown activities during the period. Control of off-normal activities by unit supervisors appeared to be improving. However, the inspectors observed an apparent increase in personnel errors which affected important plant equipment. Many of these may not have occurred had the procedure in place been followed and/or a good self-check been performed. The following examples from operations, maintenance, and engineering indicated that the similar problems existed throughout the plant:

- Maintenance workers improperly inserted a plug into a scram solenoid air vent line, rendering a control rod unable to trip.

- A maintenance foreman and technician performed inadequate visual inspections as required by a work request on a control rod hydraulic control unit.

- A system engineering test director failed to assure that a rod worth minimizer was set up according to procedure during control rod scram time testing.

- A system engineer caused rod scram testing to be performed on a control rod from the wrong unit.

- An operator incorrectly secured the oil cooler to an operating reactor recirculation motor generator.

- Operators attempted to start a reactor feed pump with the discharge valve closed.

- An improper out-of-service boundary caused an instrument air pre-filter top to blow off under pressure during maintenance.

Details of some of these events follow.

a. Control Rods Fail to Scram

On August 29, 1994, with Unit 1 at about 21 percent power, two control rods failed to insert upon demand during individual rod scram time testing. The inspectors reviewed the cause for these failures and the licensee's response, and found several problem areas. These areas included failure to follow maintenance procedures, poor corrective actions for control rod failures, and inadequate post maintenance testing. The overall review of activities showed a lack of sensitivity to important issues which affect safety systems and reactivity management. Procedure issues, post maintenance verification, and post maintenance testing are discussed in this section.

Rod L-11 on Unit 1 failed to insert when tested because a plug had been inserted in the vent path for the rod's scram solenoid pilot valves (SSPV) during maintenance. The inspector identified through interviews with maintenance technicians, that installing a plug in the SSPV vent was a common maintenance practice, even though not described in the procedure governing control rod drive (CRD) maintenance, Quad Cities Mechanical Maintenance procedure (QCMM) 300-34, "CRD HCU Scram Inlet and Outlet Valves Overhaul and Inspection," Revision 1, dated February 17, 1994.

QCMM 300-34, Section I, Step 5, guided the disassembly of the scram pilot valve, including the pneumatic tubing between the pilot valve and the outlet scram valve. Step 13 of the procedure required hook-up of regulated air to the top of the outlet scram valve diaphragm case. Step 14 of the procedure directed reconnection of pilot valve pneumatic tubing including the

connection to the outlet scram valve diaphragm case. The maintenance technician for Nuclear Work Request (NWR) Q11247 (authorized 4/11/94) failed to follow the procedure steps detailed in QCMM 300-34 in that the technician did not connect the regulated air directly to the outlet valve diaphragm case. Instead, the air was connected to pneumatic tubing which should have been removed in Step 5 of the procedure. Since this method inserted a leakage path for air through the scram solenoid pilot valve (SSPV), the technician installed a plug in the SSPV exhaust port, which was not described in the procedure. The technician failed to remove the plug when maintenance was completed.

The inspector also identified through interviews that other parts of the same procedure were not followed, under other conditions, such as when the scram outlet valve did not require maintenance. The inspectors discussed with licensee management the concern that poor procedure adherence had introduced the possibility of affecting many control rods and other components.

The licensee also failed to ensure that adequate post maintenance verification and testing were performed to verify that maintenance performed on the SSPVs for control rod L-11 left the valves in an acceptable condition.

NWR Q11247, which governed the maintenance, required a visual inspection of the completed work. The visual inspection was signed complete on April 17, 1994, but failed to identify an easily visible plug left in the SSPV vent port during maintenance. Procedure QCMM 300-34, Step 14 required the maintenance mechanic to sign for verification that all work was completed, the area was cleaned, and discarded material was removed.

QCMM 1530-11, "Post Maintenance Verification Guide for Passive Visual Inspection," revision 2, dated November 12, 1993, was also used to perform an inspection for NWR Q11247. In accordance with that procedure, the maintenance foreman was to verify that all air piping was properly oriented, and the area was clean of all debris from the work activity. Those inspections were signed off as satisfactorily completed on April 17, 1994, even though an unauthorized plug was in the vent port for control rod L-11's SSPV. A later system walkdown by the system engineer also failed to identify the installed plug.

Technical Specifications Section 6.2.A states that procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, shall be established and implemented. Regulatory Guide 1.33 included plant maintenance procedures that can affect the performance of safety related equipment.

Failure of plant technicians to follow procedure QCMM 300-34 during maintenance work on control rod L-11 inlet and outlet valves is an apparent violation (254/265-94017-01a(DRP)) of the

procedural requirements and Technical Specification 6.2. Failure of the maintenance foreman to properly implement the post maintenance inspection required by QCMM 1530-11 following work on control rod L-11 inlet and outlet valves is another example of an apparent violation (254/265-94017-01b(DRP)) of the procedural requirements and Technical Specification 6.2.

No further post maintenance testing was performed for the solenoid valves until after the Unit 1 restart following the refueling outage. Testing of the ability of the SSPV to vent air (the safety related function) was not performed until the unit was at about 21 percent power, even though maintenance was performed which could have affected that function. The inspectors noted that the licensee did not have an adequate program to post maintenance test these valves which were vital to carry out the function of the reactor protective system. Post maintenance testing was performed at power in conjunction with rod scram timing. The rod scram timing test was not intended to be a functional test for operation of the SSPVs after maintenance.

10 CFR 50, Appendix B, Criteria XI, "Test Control," states, in part, that a test program be established to assure structures, systems, and components will perform satisfactorily in service. Failure to perform adequate post maintenance testing following the April 1994 maintenance on control rod L-11's control valves is considered an apparent violation (254/265-94017-02(DRP)) of 10 CFR 50, Appendix B, Criterion XI.

b. Testing of Wrong Control Rod

On September 30, 1994, engineering personnel performed a pre-maintenance functional test on an incorrect control rod hydraulic control unit (HCU). NWR Q18180 identified Unit 1 control rod F-10 HCU to have its SSPVs replaced. The qualified nuclear engineer selected Unit 2 control rod instead of Unit 1 for performance of Interim Procedure 881, "Control Rod Scram Timing Prior to Maintenance," dated September 30, 1994. Failure to test the proper control rod in accordance with Interim Procedure 881 is another example of apparent violation (254/265-94017-01c(DRP)) of the procedural requirements and Technical Specification 6.2.

c. Control Rod Scram Timing Error

On September 28, 1994, system engineering personnel failed to ensure the rod worth minimizer (RWM) was placed in the scram timing or bypass mode, as directed by Quad Technical Staff procedure (QTS) 130-4 "CRD Scram Timing," Revision 22, dated August 1992. Control rod M-10 was tripped twice without receiving a computer output before the problem was identified. Failure to follow QTS 130-4 while testing control rod M-10 is another example of apparent violation (254/265-94017-01d(DRP)) of the procedural requirements and Technical Specification 6.2.

d. Loss of Cooling Water to the 2A Recirc Pump Oil Cooler

On August 31, 1994, operations was preparing to secure the Unit 2 2B recirculation motor generator (MG) set to initiate repairs to the MG set speed control circuit transformer and resistors. (See section 3.d. of this report.) A briefing was held prior to manipulating valves to the coolers of the MG sets, with the shift engineer, unit operating engineer, unit supervisor, unit nuclear station operators (NSOs) and the Unit 2 equipment operator (EO) in attendance. The service water (SW) to the 2B cooler was to be isolated.

When attempting to secure the 2B cooler, the Unit 2 EO mistakenly isolated the 2A oil cooler SW isolation valve. The Unit 2 EO had not reviewed the procedure prior to performing the valve manipulations. The Unit 2 NSO called the Unit 2 EO and asked what had been done at the coolers because the NSO observed that the 2A MG set oil temperature was rising fast. The Unit 2 EO realized the mistake, and asked the Unit 1 EO to open the SW isolation valve to the 2A cooler. The Unit 1 EO corrected the lineup, and MG set oil temperature returned to normal.

The inspectors concluded that the main cause for this event was that operators failed to perform a self-check and failed to review the procedure prior to performing the task.

The licensee also identified that Quad Cities Operating Procedure (QCOP) 202-2, "Reactor Recirculation System Startup," which dealt with the restart of a recirculation MG set, did not require the SW isolation valves to the cooler to be opened. Operators controlled the reopening of the SW valves by use of a caution card. Operations management later corrected that practice.

Although the need for self-check was important, the safety significance of this event was minimal, and no equipment damage was sustained. The inspectors will continue to monitor the licensee's action to reduce personnel errors.

e. 2A Reactor Feed Pump

During the report period, a Unit 2 nuclear station operator (NSO) prepared to start the 2A reactor feed pump (RFP) and secure the 2B RFP. The NSO reviewed the procedure prior to starting the evolution. The 2A RFP had just been returned to service, and the NSO assumed that the pump would be in a proper standby lineup. Immediately after the 2A RFP pump was started the NSO identified low flow conditions and shut down the 2A RFP. The NSO then noticed that the 2A RFP discharge valve was closed.

Prior to the initial pump start, the NSO did not review the return to service package nor verify that the pump lineup was in agreement with the RFP changeover procedure. Quad Operating

Procedure (QOP) 3200-4, contained a step to verify the discharge valve was opened prior to pump startup.

Although the need for procedure adherence was important, the safety significance of this event was minimal, and no equipment damage was sustained. The inspectors will continue to monitor the licensee's action to reduce personnel errors.

One apparent violation with four examples was identified regarding failure to follow procedures. One apparent violation regarding adequate post maintenance testing was also identified.

3. Material Condition

Many equipment problems were addressed during the Unit 1 refueling outage. Significant residual heat removal (RHR) system work was accomplished. Rotating equipment repairs were made to equipment such as core spray and low pressure coolant injection motors, condensate and condensate booster pumps, RHR service water pumps, and feedwater pumps. After the outage, operations and engineering persistence resulted in a successful repair to longstanding problems with Units 1 and 2 high pressure coolant injection (HPCI) drain pot alarms.

However, some poor material conditions continued to affect plant systems, burden operators, and cause transients. Problem areas included:

- The 1A control rod drive (CRD) pump was recently rebuilt; however, that pump was to be used only for emergencies due to thrust bearing degradation.
- Turbine building pressure was often positive due to exhaust ventilation fan problems.
- Several reactor building ventilation fans were degraded, and reactor building ventilation trips continued.
- Control room ventilation tripped several times this period.
- Toxic gas analyzer failures continued to cause control room ventilation to go into emergency recirculation mode.
- Service water radiation monitor systems were out of service for long periods.
- The 250 volt battery chargers were out of service, and nearly forced a unit shutdown.
- Main steam line flow detectors sensitivity to vibrations continued, which directly led to a Unit 2 reactor trip.

- A master feedwater controller on Unit 1 caused three level transients in eight days.

- RHR service water pumps were out of service for long periods including the "B" pump which was in day 28 of a 30 day limiting condition for operation at the close of the period.

- The Unit 2 bus duct high temperature problems caused power reductions.

- Feedwater flow reversing valves caused condenser vacuum problems.

Details of some of these areas follows:

a. Control Room Emergency Ventilation System Inoperability

On August 8, 1994, control room ventilation (CRV) was being provided by the non-safety related "A" ventilation system. When temperatures in the control room elevated to uncomfortable levels, operators switched ventilation over to the safety-related "B" system. The "B" train ventilation system air compressor would not remain running. Operators switched CRV back to the "A" side, but those compressors also tripped. The CRV system was switched to outside ventilation to reduce control room temperatures. Operators declared the "B" train inoperable, and notified the NRC. Maintenance personnel implemented a duplex strainer on the service water (SW) supply to the compressors, and found the strainer clogged with silt. The strainers were cleaned and placed back in service. Operators tested the safety-related "B" train CRV, and declared it operable on August 9. On August 11 another duplex strainer supplied from the same water source became clogged, necessitating cleaning.

Engineers attributed the silt build up to a combination of cleaning the intake screens, and low service water (SW) system flow due to low system demand. The CRV SW duplex strainer was cleaned at least monthly according to the surveillance schedule, but was required to be cleaned more frequently due to the low flow conditions in the SW system.

The "B" train CRV system compressor was cooled by either non-safety supply SW or safety-related service water (RHRSW). The RHRSW system was available for service but operators did not place the system in service since flow from the SW system was indicated. The operators did not realize that the flow indicator was faulty. The false indication hampered the operators efforts to diagnose CRV system problems. The licensee wrote a work request to repair the faulty flow indicator, and changed the system operating procedure to place RHRSW in service if the compressors would not run on SW.

b. 2C Residual Heat Removal Service Water (RHRSW) Pump Repair

The licensee used predictive maintenance techniques that were used to prioritize repairs of major equipment before component failure. Vibration monitoring and oil sampling were methods used to prevent more costly repairs and had a strong potential to improve overall performance of safety equipment.

Since vibration readings showed a potential problem, an oil sample of the high pressure 2C RHRSW pump outboard bearings was taken. The results showed abnormal levels of contaminants present, and the decision was made to change the oil. Subsequently, the pump was run, and an oil sample sent to an outside laboratory. That sample result indicated high levels of iron and silica. Thermography readings indicated bearing housing seal temperature was high (220 degrees F) and the bearing housing temperature was slightly elevated. The licensee elected to disassemble and inspect the bearing.

The inner bearing race was found to have been rotating freely around the shaft (normally a press fit). The bearing inner race had worn a groove in the shaft and rubbed against the shoulder. The noted condition explained the results of the oil analysis.

The bearing manufacturer was contacted and requested to provide tolerance requirements between the shaft diameter and the inner bearing. The old shaft diameter, as accurately as could be determined due to wear, was too small. The new shaft met the tolerance requirements.

A weakness noted by the inspectors was that the new pump shafts did not receive a receipt inspection to specifically verify tolerances, nor were any such instructions in the work package that installed the new shaft. The work package to rebuild the pump did not include steps to measure the shaft diameter prior to installing the bearing. The inspectors discussed with licensee management the noted missed opportunities to check critical parameters, such as shaft tolerance, could be a likely cause for rework.

c. Local Power Range Monitors (LPRMs) Bypassed

The inspectors reviewed the number of LPRMs taken out-of-service or bypassed during power operation and prior to start-up. The numbers ranged from 6 to 20, within the Technical Specification allowable limit of 42. The licensee stated that General Electric's neutron diffusion calculation and the Panacea Code did not rely on LPRMs as much as the old calculation methodology. Siemens Power Company's POWERPLEX methodology also provided a similar advantage. However, the inspectors were concerned with the material condition of the LPRMs. An opportunity was missed

during plant startup, when plant conditions would have allowed repair activities, to restore LPRMs to an operable state. This item will be reviewed during a future inspection.

d. Loss of 2A Reactor Recirculation Coolant Pump

On August 30, 1994, the Unit 2 operator received a computer point alarm for reactor vessel water level high. Normal water level was 30 inches, and the computer setpoint was 32 inches. After receiving the alarm, the operator noted a decrease in power from 790 to 730 MWe. The unit supervisor and operator started a systematic panel walkdown. The walkdown found the 2A recirculation pump speed indication lower than expected, and jet pump flow had decreased and stabilized. An operator was dispatched to lock the scoop tube in place. Immediately after locking the scoop tube, the operator called the control room to report smoke from either the 2A MG set control panel or the MG set itself. The 2A MG set field breaker tripped, and the operator reported that smoke decreased and verified the smoke had originated from the control panel. Station nuclear engineers were in the control room at the time of the event. The engineers monitored nuclear instrumentation as the operators inserted rods to below the 80 percent flow control line in order to match pump speed, and avoid the power to flow region of instability. Calculations later verified that the region of instability had not been entered.

The suspected cause for the loss of the recirc pump was a failed resistor in the MG set voltage control circuit that drew excessive power through the power transformer, which also failed. The solution offered by the vendor was to put two resistors in series with a higher power capacity for each resistor. The modification to the circuitry was completed for both reactor recirculation MG sets on Unit 2. The licensee planned to perform the same modification on Unit 1 at the next available opportunity. The exact causal factors as to the failure of the resistor and transformer had not yet been determined.

Quad Cities has had a history of problems with the speed control circuitry for the reactor recirculation motor generators, and was considering further options for long term repair.

No violations or deviations were identified.

4. Corrective Actions:

Several occurrences indicated that corrective actions to resolve identified problems were weak.

- On August 29 three control rod problems surfaced with two failing to trip when tested during plant operation. The significance of two rods failing to trip with indications of potentially more

scram solenoid pilot valve (SSPV) problems, was apparently not understood or acted upon throughout the station organization.

- Biocide injection was identified as an issue which needed implementation in 1992, and was still not in effect. Zebra mussels have been found at the river intake structure.

- The safe shutdown makeup pump limiting condition of operation (LCO) was not effectively tracked until about day 45 (67 day LCO), which strained the engineering and procurement resources.

- A supervisor's good finding that an individual was not properly performing fire watch tours was not adequately addressed in the licensee's corrective action program. No attempt was made to follow up on the extent of the missed tours or whether there were problems in other areas.

a. Control Rod Failure to Trip - Corrective Actions for Pilot Valve Diaphragm Degradation

Control Rod R-7 failed to scram during control rod scram time testing on Unit 1, with the unit at about 21 percent power. The suspected cause was hardened diaphragms on a scram solenoid pilot valve (SSPV) for the associated hydraulic control unit (HCU). The licensee wrote a problem identification form to document the problem, gave it a level 4 (low) priority, and wrote a work request to repair the SSPV. The licensee did not initially consider operability of other rods potentially affected by this problem on Unit 1, which was operating at the time, or Unit 2 which was started up several days later.

The inspectors reviewed maintenance records with system engineers for other problems with control rod SSPVs at Quad Cities. The following list summarizes recent problems attributed to SSPV diaphragm hardening:

- May 1993 - One rod exhibited delayed start of motion (DSOM).

- July 1993 - Three rods DSOM.

- December 1993 - Four rods DSOM, ONE ROD FAILED TO SCRAM due to degraded diaphram.

- January 1994 - Seven rods DSOM.

- August 1994 - Seven rods DSOM, ONE ROD SCRAMMED due to a cracked diaphragm, ONE ROD FAILED TO SCRAM due to degraded diaphram.

- September 1994 - Eight rods DSOM.

All of the problems listed involved diaphragms installed since 1990 containing elastomers made of Buna-N material.

General Electric Service Information Letter (SIL) 575 was issued in October 1993 to discuss problems with slow start of motion of control rods due to SSPV failures. The SIL recommended that Buna-N materials in SSPVs be limited to a three to four year life.

In May 1994, General Electric issued Rapid Information Communication Service Information Letter (RICSIL) 69, Revision 0 and Revision 1, which discussed an increased rate of hardening and cracking of SSPV diaphragms. The RICSIL identified that premature aging of the diaphragms caused failures in less than three years time. General Electric recommended in the RICSIL: 1) that affected SSPV owners identify which SSPVs were refurbished or replaced more than two years ago using diaphragm kits or new valves with assembly dates of 1989 or later; 2) that a sampling of the most susceptible SSPV diaphragms be examined for cracking and excessive hardening; and 3) that if the evaluation indicated near end of life conditions, to replace the diaphragms and continue testing on other SSPV diaphragms. The system engineering response to this RICSIL dated July 29, 1994, indicated that this RICSIL applied to the Quad Cities station. The response stated, "As SSPVs are identified by our scram timing, we initiate a work request to change them out at the next available opportunity," and "as this item is only for comments, this item is closed." A similar response was made to the 10 CFR, Part 21 Safety Communication 94-03 issued for the same subject.

In June 1994, the licensee rebuilt SSPVs for seven rods that showed DSOM in January 1994. Diaphragms from some of these SSPVs were found to be hardened, and sent to General Electric for testing in July 1994. General Electric confirmed that the diaphragms showed excessive hardening and kept the samples for further testing. Action on testing was delayed, and no further results were available at the close of the period.

The licensee's failure to take comprehensive corrective action on previously identified diaphragm failures, vendor information, and 10 CFR 21 safety communications resulted in continued control rod failures. These included the failure of Unit 1 rod R-7 to insert on August 29, 1994; the inadvertent scram of Unit 2 control rod D-11 on August 29, 1994; and DSOM on at least 15 control rods from both units since the units were started in late August 1994. At least two of the DSOM rods also failed to meet technical specification scram timing requirements. The failure to take comprehensive corrective action continued until after the inspectors discussed this issue with senior licensee management in September 1994.

10 CFR 50, Appendix B, Criteria XVI, "Corrective Action," states, in part, that in the case of significant conditions adverse to

quality, corrective action measures shall assure the cause of the condition is determined and corrective action taken to preclude repetition. Failure of the licensee to identify and take effective corrective action for repeated control rod scram solenoid pilot valve problems, a significant condition adverse to quality, is considered an apparent violation (254/265-94017-03(DRP)) of 10 CFR 50, Appendix B, Criterion XVI.

b. Control Rod Failure to Scram - Corrective Actions for Plugged Vent

The inspectors reviewed the licensee's response to the failure of control rod L-11 to scram. Several weaknesses were identified.

- The system engineering group and shift engineer evaluated that the backup scram valves would have tripped all rods, indicating a less than detailed look at system operation. The inspectors identified that the L-11 rod would not have promptly tripped with backup scram valve operation.

- The level 3 investigation was heading in the direction of implementing corrective action for a perceived "weak procedure" for the plug left in the L-11 rod, rather than identifying that the procedure was adequate; but, the technicians did not follow it. The inspectors identified that the technician's deviation from the procedure led to the error.

- The post maintenance testing and verification issue was not addressed. Engineering and maintenance initiated less conservative procedure changes by proceduralizing solenoid valve plug use, without providing post maintenance testing of SSPV operation.

- Even with SSPV failures (found during scram time testing) and a Unit two rod scram, the licensee did not perform a timely operability evaluation.

c. Falsification of Fire Watch Logs

A fire watch supervisor audited a fire watch tour to ensure that the tour was conducted in the required time period to meet Appendix R requirements. The supervisor noted that the fire watch did not appear in the reactor building basement for the fire watch tour. The supervisor conducted the fire watch tour for the area to ensure that the area was properly toured. The fire watch log completed by the responsible individual indicated that the tour of the reactor building basement was performed. The licensee took disciplinary action against the fire watch.

The licensee performed frequent supervisor monitoring of fire watch tours, and no other discrepancies of fire watch tours had been discovered. The decision to discipline the fire watch was

made by the contracted supervisor, and the licensee fire protection staff was kept informed.

The inspectors were concerned that no problem identification form was written, nor was licensee management informed of the incident until after mid-August when the inspectors raised questions about the incident. The licensee had not determined the extent of missed tours or whether the problem existed with other groups. The subsequent investigation determined that the fire watch was in the turbine building at the time of the incident, but the tour route conducted by the fire watch in the building could not be verified.

Failure to properly implement fire prevention rounds is a Violation of 10 CFR Part 50, Appendix B, Criterion V. However, this violation is not being cited because the criteria specified of 10 CFR 2, Appendix C, VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Action" were met.

d. Problems Identified With Limiting Condition for Operation (LCO)

The inspectors identified several problems during review of the Unit 2 fire protection administrative limiting condition for operation (LCO) for the safe shutdown makeup pump (SSMUP). Station management was not tracking the SSMUP LCO until day 45 of its 67 day LCO. The LCO for the SSMUP was entered on the list of LCOs maintained in the shift engineer's office, but that information was not transferred to the plan of the day (POD) as expected. The POD was the management tool for tracking all LCOs from day one until the LCO was exited. The unit operating engineers were responsible for adding new LCOs to the POD, but had overlooked the SSMUP.

The SSMUP was declared inoperable after a fire protection engineer found that a previously identified deficiency had not been corrected. NRC Inspection Report 50-254/265-91025 and licensee Audit Report 04-91-I identified that hand switches were installed that allowed operators to remotely stop the fire pumps from the control room. The concern was that a short circuit condition in the fire pump control circuit could shut down the fire pump during fire fighting operations. The fire pumps supplied the cooling water for the SSMUP room coolers. Although the problem was identified originally 1989, the licensee had not taken action to resolve the issue.

Another problem was that work on the modification package by site engineering and construction (SEC) was not started until day 41 of the LCO. A PIF on the SEC oversight was not generated until the inspectors raised the issue of LCO tracking by SEC.

One apparent violation was identified regarding inadequate corrective action to preclude repetition of control rod scram solenoid valve failures.

5. Follow-up of Events (93702):

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC via the emergency notification system (ENS) pursuant to 10 CFR 50.72, and other requirements. The specific events were as follows:

August 8	ENS call to report worker finding Sr-90 source in pants pocket (ref. IR 254/265-94021, dated September 8, 1994.
August 8	ENS call to report inoperability of "B" train of control room ventilation system.
August 21	ENS call to report Unit 1 shutdown from 150 psi due to high pressure coolant injection (HPCI) system inoperability.
August 23	ENS call to report Unit 2 reactor trip, and Group 1 primary containment isolation.
August 27	Unit 2 synchronized to grid.
August 28	Unit 1 synchronized to grid. Power ascension gradual.
August 29	ENS call to report Unit 2 control rod inserted due to scram solenoid pilot valve failure.
August 29	Unit 1 Rod L-11 failed to trip during testing due to pipe plug found in scram solenoid vent port.
August 29	Unit 1 rod R-7 failed to trip due to scram solenoid pilot valve failure.
August 30	Unit 2 "A" recirculation motor generator (MG) set tripped due to failed resistor and control power transformer.
Sept. 9	Flow tap on Unit 1 "C" reactor feed pump found missing.
Sept. 29	ENS call made for pipe plug found in vent port of scram solenoid pilot valve.

Single Control Rod Automatic Insertion

On August 29, 1994, during performance of Quad Cities Instrument Surveillance procedure (QCIS) 200-3, "Monthly Reactor Water Level Calibration and Functional Test," technicians generated a half-scram condition to the reactor protection system (RPS) on Unit 2. Since a half-scram did not satisfy the logic required to produce control rod motion, control rods on the unit were not expected to move. However,

the half-scram signal resulted in control rod D-11 inadvertently inserting. A SSPV associated with hydraulic control unit for rod D-11 was identified as having a perforated diaphragm which was indicative of diaphragm hardening. The inspectors had concerns with the licensees' response to vendor notifications on deficient diaphragms in scram solenoid pilot valves. See section 4.a.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

The inspectors observed control room operation, reviewed applicable logs, and conducted discussions with control room operators. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. During tours of the facility, the inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection and physical security plan controls.

a. Unit 1 Startup

On August 19, 1994, operators commenced Unit 1 startup. The reactor was made critical at about 2:10 p.m. Licensee management oversight was present in the control room during the startup. Communications between operators was good, and the startup was performed in accordance with licensee procedures. Reactor core isolation cooling (RCIC) turbine was tested satisfactorily after repairs were completed. However, the high pressure coolant injection (HPCI) turbine was tested with unsatisfactory results and necessitated a Unit 1 shutdown on August 21.

During the startup other equipment problems occurred requiring repairs. The "1B" recirculation pump seal pressures were abnormal, requiring the replacement of the pump seal. A valve in the residual heat removal system had a packing leak, the turbine lift pump system pressure was too low, and a turbine bypass valve required maintenance.

The licensee completed repairs and commenced Unit 1 startup on August 25. The approach to criticality was slow and conservative, and management oversight was present in the control room.

b. Unit 2 Trip and Subsequent Startup

On August 23, 1994, Unit 2 automatically shut down from full power. A Group 1 primary containment isolation signal (PCIS) occurred. That signal caused all the main steam isolation valves (MSIVs) to close. When the MSIVs reached about 90% open, the reactor protection system (RPS) automatically tripped the reactor. Reactor water level lowered below +8 inches after the scram as expected, causing a Group 2 and 3 PCIS, isolating reactor building

ventilation, starting the standby gas treatment system, and isolating the control room ventilation system. Reactor pressure increased to about 1095 psig causing a relief valve to lift. The relief valve was set to lift at 1115 psig. All equipment operated as expected after the reactor trip, with the exception of a scram discharge volume drain valve which displayed a dual position indication.

The licensee's investigation determined that the high steam flow condition occurred due to inherent system vibrations, and was exacerbated when workers bumped an instrument rack support for the main steam line flow instruments. The licensee was able to repeat the condition during troubleshooting activities. The licensee installed signs and insulating material in the vicinity of the detector racks to minimize vibrations to the instruments. Long term solutions were still being evaluated, including a modification which had previously been proposed to change out the main steam line flow instruments.

The scram discharge drain valve was tested after the scram with no problems noted. A work request to troubleshoot the valve was planned to be performed in a future outage.

After Unit 1 startup on August 25, the licensee held Unit 1 stable at about 6 percent power during Unit 2 startup. The Unit 2 reactor was made critical, and synchronized to the grid on August 27. Equipment performed properly during the startup. The approach to criticality and unit startup was conservative, with licensee management oversight present during startup.

c. Missing Feedwater Flow Probe

When the feedwater flow test suction probe for the Unit 1 "C" reactor feed pump was removed, approximately eight inches of the probe was found to have broken off. Suspected cause for the failure was fretting from high vibration. The probe was made from quarter-inch tubing which was inside of a schedule 80 three-quarter-inch pipe. It was suspected that the quarter inch gap between the tubing and the pipe allowed excessive movement of the probe.

The licensee sent the remaining section of the 1C probe to a laboratory for analysis. The preliminary results indicated the possible failure mechanism was transgranular stress corrosion cracking (TGSCC). The inspectors asked if service information letter (SIL) 257, "Improved Feedwater Sample Probe," had been reviewed. The SIL recommended welding the probe to the pipe to avoid chloride or halide contamination between the pipe and probe. The SIL had been reviewed, but it was determined that due to the length of time the probes would be in service, the recommendations to guard against TGSCC were not followed. The SIL also indicated

fatigue was not considered to be a significant contributing factor in the failure. However, the design outlined in the SIL described a much shorter probe length.

The licensee expended considerable effort to find the probe. The feedwater flow control and minimum flow valves were radiographed. No trace of the probe was found. The engineering operability evaluation was thorough, and determined that operations could continue since a path for the missing piece to the reactor was unlikely but within acceptable design analysis.

No violations or deviations were identified.

7. Monthly Maintenance Observation (62703)

Station maintenance activities for both safety related and non-safety related systems were observed and/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 maintenance activities were observed and reviewed:

Unit 1

Q17393	Foreign Material Exclusion Inspection of 1B RFP Suction
Q17163	1B CRD Pump Work
Q12187-05	RHR 36A Valve Work
Q17609	Repair Air Leak On HCU 22-47 Scram Air Solenoid
Q12187-05	Replace Anti-Cavitation Trim in Valve RHR-36A
Q17181	Disassemble, Inspect/Repair Bearing, Reassemble 2C RHRSW Pump
Q17292	Inspect 1B Condensate Polisher Filter
Q18100	250 VDC Battery Charger--Troubleshoot and Repair Output Voltage Oscillates 250-280 VDC
Q13008	Reprogram Unit 1 HPCI Flow Controller

Unit 2

Q17181	Repairs to 2C RHRSW Pump Seal and Bearing
Q17781	Replacement of 20K ohm Resistor and Control Power Transformer for the 2A Recirc MG Set
Q17779	Rebuild Control Rod Drive Scram Solenoid Valves for Rod D-11

a. Unit 1 High Pressure Coolant Injection (HPCI) Problems

Startup activities on Unit 1 were stopped on August 21 due to problems encountered when testing the HPCI system. The testing revealed divergent flow oscillations when the flow controller was in automatic. Troubleshooting determined that a wire connected

between a transducer and the motor gear unit was damaged due to stress and age. The licensee replaced the wire.

Additionally, the licensee identified deficiencies introduced when the flow controller was reprogrammed during the outage. A program input parameter was installed incorrectly due to inadequate work package instructions. The licensee determined that the software abnormalities were not the cause of the HPCI flow oscillations and the program error would not have rendered HPCI inoperable. The HPCI flow controller was reprogrammed with the correct parameter and satisfactorily tested. Both units' reactor core isolation cooling (RCIC) controllers and the Unit 2 HPCI flow controller were confirmed to have been programmed correctly.

The program error would have required operators to manually enter the desired flow setpoint if electrical power to the flow controller was lost. The licensee determined that the work package down-loaded the "as-found" program parameters incorrectly, and the technicians were not properly trained.

The safety significance of this event was minimal. The inspectors concluded that the licensee's investigation to discover work control weaknesses associated with this event was good. This event also demonstrated deficiencies with technician training for the detection and correction of digital program errors. The licensee planned to develop and utilize a standard procedure to retrieve and input data into the program.

b. Failure Of A Motor Operated Valve (MOV) Due To Vendor Manual Discrepancy

Previous maintenance process errors led to a problem being continuously overlooked during maintenance on SMB-2 motor operator valves (MOVs). However, response to the issue was prompt and thorough once a core spray discharge valve was found inoperable.

During performance of a functional test on the 1-1402-25B, core spray (CS) discharge valve, the valve operator failed. The valve was in the manual mode, and was attempted to be opened electrically. The motor ran the unit, but would not open the valve.

Technicians disassembled the valve operator and identified the cause of the valve operator failure to be a missing spacer on the worm shaft drive assembly. The missing spacer allowed a compression spring to ride up on the shaft, and cause a loss of pretension of the spring. The loss of pretension caused the worm shaft clutch not to shift to the motor operated mode. The operator was a Limitorque model SMB-2.

The controlled copy of the vendor manual had guidance in a footnote to a drawing that stated a spacer was required for a SMB-

0 and SMB-1, but not a SMB-2 operator. Technicians had previously rebuilt SMB-2 operators and included the spacer even though it had not been required by the drawing. Limitorque was contacted following the CS valve failure to clarify the issue. The vendor indicated that the spacer was required in SMB-2 operators for proper operation.

There were 22 valves identified as safety-related, and having SMB-2 operators for both units. An inspection of the safety-related valves on Unit 1 having an active safety function found that the spacers were installed. Because no problems were identified with the inspected valves, the licensee determined the remaining questionable valves on Unit 2 (five) would have performed as required. Also supporting this conclusion was a review done on the last surveillances involving the last five valves. Caution cards were hung on the remaining valves stating that if the valve was manually operated, the valve shall be immediately stroked with the operator in the electrical mode to verify proper operation.

Other corrective actions included:

- Work requests were written to open and inspect the Unit 2 valves at the next available limiting condition of operation (LCO) window for the respective valve.
- An operability assessment was performed by engineering.
- Tailgate training was outlined for maintenance personnel to ensure a questioning attitude and procedure compliance. This was to resolve the issue of how the spacers were correctly installed without procedural guidance to install them.
- The PIF that identified the issue was forwarded to the Part 21 committee for review.
- There were direct discussions between Limitorque and the MOV group onsite to call attention to the issue and assess possible solutions.
- Interim administrative controls were put in place in case a work request was required on a SMB-2 operator until the issue was resolved.

Licensee followup on this issue was good, and uncovered a potentially generic problem with SMB-2 operators.

No violations or deviations were identified.

8. Monthly Surveillance Observation (61726)

During the inspection period, the inspectors observed test activities. Observations made included one or more of the following attributes: testing was performed in accordance with adequate procedures; test equipment was in calibration; test results conformed with technical specifications and procedure requirements; test results were properly reviewed; and test deficiencies identified were properly resolved by the appropriate personnel.

The inspectors witnessed or reviewed portions of the following test activities:

Unit 1

QTS 130-4	Control Rod Scram Timing in the Hot Condition
QCOS 1300-7	RCIC Manual Initiation Test RCIC MOV DP Testing on 1301-61 and 1301-53 Valves
QCTS 301-1	Unit 1 Emergency Core Cooling System Simulated Automatic Actuation and Diesel Generators Auto-Start Surveillance
QCTP 920-2	Initial In-Sequence Criticality Estimate Evaluation

Unit 2

QCMMS 6600-2	Emergency Diesel General Preventive Maintenance Quarterly Inspection
QCOS 2300-5	Quarterly HPCI Pump Operability Test
QCIS 200-3	Monthly Reactor Water Level Calibration and Functional Test
QCOS 2300-5	Quarterly High Pressure Coolant Injection Pump Operability Test
QCTP 920-2	Initial In-Sequence Criticality Estimate Evaluation

No violations or deviations were identified.

9. Engineering and Technical Support (71707)

Determination of Core Spray (CS) System Operability

Prompt operability determinations continued to be a weakness. Engineering failed to notify operations that expected and actual flow results differed for the CS pump minimum flow line test. No problem identification form (PIF) or other notification to operations by the technical engineering staff was initiated.

During the report period, a special test was conducted to determine CS pump minimum flow for the four CS pumps. Expected minimum flow was 185 gpm; however, actual flow was lower on Unit 1 pumps and higher on Unit 2 pumps. Normal action was to immediately write a problem identification form (PIF) identifying the discrepancy, and to notify the shift engineer (SE). In this instance, a PIF was not generated until the following day, after the inspectors questioned system engineering as to why the problem had not been documented.

On September 6 a test was performed that measured the flow rates passing through each of the four CS minimum flow lines. Using an ultrasonic flowmeter, the following flow rates were achieved: 1A-150 gpm, 1B-145 gpm, 2A-195 gpm, and 2B-240 gpm. The flow acceptance criteria was supported by vibration, noise, and historical performance.

The licensee agreed that the lower than expected flow rate should have been brought to the attention of operations, so an immediate operability determination could have been made. Operations declared the CS system operable based on data from previous testing, while awaiting further documentation from engineering. Engineering was in the process of gathering additional data to further support the conclusion that the measured flow below 185 gpm was sufficient for CS system to be considered operable.

No violations or deviations were identifi

10. Regional Request

Licensee Response To Information Notice (IN) 94-42 "Cracking In The Lower Region Of The Core Shroud In Boiling Water Reactors (BWRs)"

The identification of shroud cracking at two of the licensee's BWRs prompted a number of NRC and industry actions. The NRC issued IN 94-42 to alert the industry that cracks had been observed at welds in the lower region of the core shroud in the reactor vessel.

Following the inspection guidelines of General Electric (GE) SIL 572 Revision 1, the Unit 1 core shroud was inspected in May 1994 during the Q1R13 refueling outage. The scope of the core shroud inspections at Quad Cities Unit 1 consisted of a visual examination of the circumferential shroud welds H1 through H7 from the outside diameter and, where accessible, from the inside diameter. Also, if both inside and outside welds could not be visually examined, an ultrasonic examination was performed.

The visual examination was conducted by Level II and Level III certified VT-1 visual examiners from both ComEd and GE, utilizing underwater video equipment capable of resolving a 1 mil wire. Distances from the camera lens to the inspection surface varied due to accessibility. The focal distance from the camera to the inspection surface ranged between 1 to 5 inches based on crack identification methods learned from Dresden. The inspection surfaces were cleaned with nylon bristle brushes to remove loose contaminants and oxides that could inhibit the ability to detect fine crack indications. Attention was also given to lighting and camera angles to avoid shadows that could mask indications. Masking was identified at Dresden, and lessons learned were applied to Quad Cities. Additionally, all visual examinations were independently reviewed by a Level II or III certified VT-1 visual examiner in order to substantiate the inspection findings.

The outside diameter (OD) visual examinations below the H3 weld were limited to the areas between the jet pumps. This limitation restricted the maximum inspection locations from the OD to approximately 40% of the shroud circumference. The inside diameter (ID) visual examinations were limited to the H3 and H4 welds due to interferences from the core spray spargers and top guide above the H3 location, and the core plate below the H4 location. The ID examinations at the H3 and H4 locations were limited only by the focal distances that could be achieved through the periphery of the top guide.

The inspection identified some cracks, including a circumferential shroud crack. The results, including a safety evaluation for continued operation, were sent to the NRCs Office of Nuclear Reactor Regulation (NRR). NRR approved and issued a safety evaluation review (SER) on the Unit 1 core shroud based on analysis and a repair to be completed not later than 15 months of operation. NRR requested further information from the licensee regarding Unit 2. The licensee intended to submit a similar repair method presently under NRR review for another utility. The licensee was an active participant in the BWR Vessel and Internals Project (BWR-VIP) which was developing inspection and flaw evaluation guidelines.

No violations or deviations were identified.

11. Licensee Action on Previously Identified Items (92701, 92702)

(Closed) Inspector Followup Item (50-254/265-94016-05(DRP)): ECCS Suction Strainer Performance. During a closeout tour of the Unit 1 torus, the inspectors identified a minor amount of debris on one of four ECCS suction strainers. Additionally, a torus inspection after refill discovered what appeared to be masses of loosely adherent dust-like material. The inspectors were concerned that the debris could affect the performance of the strainers.

The dust-like material was analyzed by an independent laboratory and determined to be, "..a mat of fibers bunched together in a random fashion, with particles of various sizes adhering to the fibers. The particles were composed of iron, titanium, silicon and aluminum in widely varying combinations." Some of the dust-like material was vacuumed from the suppression pool, but passed through the vacuum filter. The licensee performed operability tests of ECCS equipment, drawing suction from the torus. The equipment operated normally and passed the surveillance tests for flow and pressure. Further inspections of the ECCS suction strainers revealed no clogging. The inspectors concluded that the ECCS suction strainer performance was acceptable. This item is closed.

No violations or deviations were identified.

12. Licensee Identified Violations

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 10 CFR 2, Appendix C, Section VII.B.(2). These tests are:

- It was identified by the licensee, including as a result of a self-disclosing event;
- It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation;
- The violation was or will be corrected, including measures to prevent recurrence, within a reasonable time; and
- It was not a willful violation.

One example of a violation of regulatory requirements, identified during this inspection, for which a Notice of Violation will not be issued was discussed in section 4.c.

13. Exit Meeting Attendees

The following management representatives attended the exit meeting conducted on September 30, 1994, along with others.

Commonwealth Edison Company (ComEd)

E. Kraft, Site Vice President
G. Campbell, Station Manager
N. Chrissotimos, Regulatory Assurance Supervisor
J. Hosmer, Vice President, Engineering and Construction
T. Kroll, Maintenance Superintendent
R. Martin, Quad Cities Safety Review Board Member
J. Perry, Vice President, BWR Operations
L. Tucker, Technical Service Superintendent
D. VanPelt, System Engineer Supervisor

14. Exit Interview

The inspectors met with the licensee representatives denoted in Paragraph 1 during the inspection period and at the conclusion of the inspection on September 30, 1994. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.