U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-254/94010(DRP); 50-265/94010(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: March 24 through May 11, 1994

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Reactor Projects Section 1B

Inspection Summary

Inspection from March 24 through May 11, 1994 (Report Nos. 50-254/94010(DRP); 50-265/94010(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident and regional inspectors of licensee action on previously identified items; licensee event report review; operational safety verification; monthly maintenance observation; monthly surveillance observation; report review; regional request; and events.

Results: Of the areas inspected, one non-cited violation was identified concerning control rod misposition event in paragraph 2.e. One violation with three examples was identified in paragraph 6.

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Assessment of Plant Operation

- Unit 1 remained shutdown for refueling, while Unit 2 remained at or near 97 percent power for most of the period. Operator response to off-normal events was good (paragraph 5).

- The implementation of a unit supervisor for each unit has improved the oversight of control room activities (paragraph 2.h).

- Weaknesses in operator attention to detail were identified in recorder walkdowns and interim procedure implementation (paragraph 5.a). However, operators showed a good questioning attitude and attention to detail in identifying a problem with the Unit 2 emergency diesel generator (paragraph 8.b).

- Housekeeping declined during the period (paragraph 5).

Assessment of Maintenance and Surveillance

- Two work scope reductions were initiated to manage work control problems. The torus recoat project and refueling bridge repairs were sources of delay (paragraph 6.e).

- Several problems with work control were evident. A violation was issued for working on the wrong high pressure coolant injection (HPCI) drain orifice, failure to follow procedures involving work on an RHR service water vault door seal, and failure to properly identify tagout requirements prior to moving out-of-service tags (paragraphs 6.a, 6.b, and 6.c).

- An inspector follow-up item was identified to track solenoid valve failures following the failure of two in-line recirculation sample (primary containment isolation) valves to close properly during a surveillance test (paragraph 7.a).

- Maintenance on the Unit 2 emergency diesel generator (EDG) local/remote switch was prompt and effective (paragraph 8.b).

- Maintenance follow-up on industry related undervoltage and Agastat relay problems was thorough (paragraphs 10.a and 10.b).

Assessment of Engineering and Technical Support

- The downpower transient of April 23 was caused by a relay failure that was identified in four PIFs in the past. The PIFs were not trended together or dispositioned in a timely manner (paragraph 4.a).

- Reporting a HPCI drain line orifice problem was delayed over ten days due to untimely reviews by system engineering and the problem identification form (PIF) process (paragraph 6.b).

- Operator work-arounds discovered by system engineers and maintenance workers were not identified by a PIF or corrective work requests until prompted by the inspectors (paragraph 4.c.).

<u>Assessment of Plant Support</u>

- Plant worker attitude toward personnel safety appeared indifferent at times. Management efforts to correct the problems were not completely effective. An inspector follow-up item was issued to track the progress of corrective actions (paragraph 6.g).

- Weak radiation protection practices and numerous contamination events were identified (paragraphs 5 and 6) and will be discussed in Inspection Report 254/265-94013(DRSS).

DETAILS

1. Persons Contacted

   Commonwealth Edison Company (CECo)

   *E. Kraft, Site Vice President
   *G. Campbell, Station Manager
   *R. Baumer, Regulatory Assurance
   N. Chrissotimos, Regulatory Assurance Supervisor
   *D. Cook, Shift Operations Supervisor
   M. Hayse, Site Quality Verification Audit Supervisor
   *T. Kroll, Maintenance Superintendent
   J. Kudalis, Support Services Director
   K. Leech, Security Administrator
   *A. Lewis, Assistant to Station Manager
   *B. McGaffigan, Assistant Superintendent - Work Planning
   *B. Moravec, Engineering and Nuclear Construction Site Manager
   G. Tietz, Executive Assistant to Site Vice President
   *L. Tucker, Technical Service Superintendent
   D. VanPelt, System Engineer Supervisor
   *D. Winchester, Site Quality Verification Director

   *Denotes those attending the exit interview conducted on May 11, 1994.

   The inspectors also contacted other licensee employees, including members of the engineering, operations, maintenance, and contract security staff.

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

   a. (Closed) Unresolved Item (254/88027-03(DRS);265/88028-03(DRS)):

      Control Room (CR) Reactor Vessel Water Level Indicators Not Operable for Regulatory Guide (RG) 1.97. The CR level indicators 1(2)-263-106A(B) provided accurate information only when the recirculation pumps were tripped or operating at a minimum speed. With both recirculation pumps operating during normal power operation, the CR indicators pegged upscale because of the associated transmitters 1(2)-263-73A(B) reference leg tap locations.

      The licensee committed to perform an analysis to determine if the reactor vessel water level indication would be available to the operators during accident and post-accident conditions. The analysis, as provided in a letter to the NRC dated December 9, 1991, concluded that during a plant transient, which did not present a significant challenge to either containment or the emergency core cooling systems, the recirculation pump would not trip. The recirculation pump would instead run back automatically to minimum speed after feedwater flow decreased to less than 20% of rated flow. However, in the event of a more serious accident that would challenge the containment or emergency core cooling systems, the recirculation pump would be tripped by either the high drywell pressure or by the low-low reactor water level signal. The analysis also concluded that three additional Category 3 level instruments per unit [1(2)-263-100A & B and 1(2)-263-101] would be added to the RG 1.97 Program to provide reactor level information during normal operation. The added Category 3 instruments covered the range of -60 to +60 and -42 to +358 inches indicated reactor vessel level, respectively.

Based upon a review completed by the Office of Nuclear Reactor Regulation dated January 26, 1994, the NRC staff had previously accepted the use of Category 2 or Category 3 level instrumentation for this purpose, provided the Category 1 level instrumentation was available for measuring level from the bottom of the active fuel to the level used for all automatic and manual actions. The Quad Cities level instrumentation met this requirement. Therefore, the staff concluded that use of Category 3 level instruments was acceptable for plant transients that do not significantly challenge the containment or emergency core cooling system, since Category 1 instruments would be available to the operator if the condition deteriorates. This item is closed.

b. <u>(Closed) Unresolved Item (254/92014-01(DRP))</u>: Control Room Heating Ventilation and Air Conditioning (HVAC) System Air Handling Units (AHU). This item involved potential elevated control room temperature effect on control room instrumentation during a station black out condition. In addition, NUREG 737, "Clarification of TMI Action Plan Requirements" for AHU Trains "A" and "B" running configurations were of concern. In response to NRC concerns the licensee performed testing, with satisfactory results, to verify that both AHU trains perform as designed. Testing or use of the "A" AHU in conjunction with the control room emergency filtration (CREF) system had not been performed prior to NRC prompting. In addition to the testing, a technical specification (TS) interpretation requiring entering the CREF limiting condition for operation (LCO) was initiated. A TS amendment request to address the ability to maintain control room temperatures within acceptable limits was submitted to the NRC. This item is closed.

c. <u>(Closed) Inspector Follow-up Item (254/92016-03(DRP))</u>: Inadvertent Loss of Instrument Air Compressor. The air compressor tripped on high discharge pressure due to isolation of the temporary (domestic water) cooling water supply. In response to the compressor trip, the licensee: supplied turbine building closed cooling water (TBCCW) to the compressor as a permanent cooling supply; revised Quad Cities Administrative Procedure (QAP) 300-14 "Equipment Out-Of-Service" to include measures to be taken if inadequate system documentation exists; implemented a continuing program for improvement of piping and instrumentation drawings (P&IDs); and issued an operating policy stressing the importance of not proceeding with an activity unless the result of the activity is known. Based on the licensee's corrective actions and no recent occurrence of similar events, this item is closed.

d. (Closed) Inspector Follow-up Item (254/265-92022-02(DRP)): Differential Pressure Testing of Motor Operated Valves (MOV). During troubleshooting activities for MOV 1-1001-34A, it was identified that the key-way for the pinion gear had fallen out. The pinion gear should have been staked to the key-way, and the key-way staked to the pinion gear shaft. Subsequent to the maintenance outages for Units 1 and 2 during the fall of 1993, a procedure change was implemented to inspect all MOVs for proper staking during scheduled maintenance work. No further cases of improper staking were found during the fall maintenance outages or the present Unit 1 refuel outage. Subsequent to the procedure change, only three instances of improper staking were identified. The three noted discrepancies were repaired. Based on results during recent outages and the procedure change implemented, this item is closed.

e. (Closed) Unresolved Item (254/265-94003-01(DRP)): Control Rod Mispositioning Event Root Cause. On January 27, 1994, during scram time testing activities on Unit 2, a control rod mispositioning event occurred. Immediate corrective actions included: stopping the test activity, removing the shift engineer (SE) from further duty as an SE, reassignment of the unit supervisor to shift foreman, temporary removal of the reactor operator (NSO) and nuclear engineers (NE) from shift until completion of remedial training, and briefing of all oncoming shifts of the event.

The licensee initiated a Level II investigation to identify the root causes of the event. Review of the event circumstances identified: a lack of procedural adherence resulted in moving the control rod without a special rod maneuver sheet as required, poor test control leading to an inadequate rod verification process, and improperly conducted pretest planning. Additional contributing factors included poor preparation and qualification of nuclear engineers for scram time test performance, weaknesses in the heightened level of awareness (HLA) program implementation, and a lack of adequate management oversight of the scram time testing by the unit supervisor. In addition, a lack of adequate training and management overview for implementation of the unit supervisor positions associated with administrative roles and responsibilities was considered a contributing causal factor.

Additional corrective actions completed or proposed included: communication guidelines were enhanced for rod scram time testing, considering classifying future hot scram timing as an infrequent evolution requiring HLA controls, newly prescribed independent rod verification requirements for the nuclear engineers were implemented prior to resuming the test, the "Control Rod Movement and Control Rod Sequence" procedure was revised to enhance control of rod movement activities. The inspectors found the licensee's investigation to be thorough, with root causes identified, and appropriate immediate and long term corrective actions taken.

The inspectors concluded that pulling a control rod without a pull sheet present was contrary to procedural requirements. Failure to follow procedures requiring a pull sheet was a Violation of 10 CFR 50, Appendix B, Criterion V. Additionally, failure of the nuclear engineers to verify rod movements is contrary to test procedure requirements. Failure to follow test procedure requirements is considered a Violation of 10 CFR 50, Appendix B, Criterion XI. However, the violations are not being cited because the criteria specified in Section VII.B.2 of the "General Statement of Policy and Procedures for NRC Enforcement Actions," 10 CFR 2, Appendix C, were met. This item is closed.

f. (Closed) Unresolved Item (254/265-94004-01(DRP)): Containment Venting At Power During Nitrogen Feed and Bleed. This issue was reviewed by the Office of Nuclear Reactor Regulation (NRR). The review concluded that the venting procedures (feed and bleed process) used by the licensee were not in violation of licensing requirements and did not constitute an unacceptable or prohibited practice. This item is closed.

g. (Closed) Inspector Follow-up Item (254/265-94004-04(DRP)): Feedwater Regulating Valve Lockup During Plant Transients. During numerous plant transients, lockup of the "2B" feedwater regulating valve occurred. Licensee review of the lockup condition identified the cause to be a problem with the valve's control circuit. During a transient, the loss of signal controller sensed a voltage perturbation and removed power from the valve. The power loss caused the valve lockup condition. A two millisecond time delay modification was installed and tested satisfactorily to resolve the problem. This item is closed.

h. (Closed) Inspector Follow-up Item (254/265-94004-20(DRP)): Shift Control Room Engineer (SCRE) Oversight of Control Room Activities. Inspectors reviewed the impact of an additional unit supervisor (US) in the control room. The current control room organization, having a US for each unit, resulted in a more controlled environment. Having a SRO responsible for each unit reduced the number of activities requiring one individual's attention. As a result of the US implementation, personnel access to the control room was better controlled. This item is closed.

i. (Closed) Inspector Follow-up Item (254/265 94004-28(DRP)): In-Service Tests (IST) of the Unit 1 HPCI Pump. The IST tests for HPCI were signed off as acceptable, with no evaluation performed to justify test anomalies. The test anomalies resulted from running the pumps at different pump speed. Discussions with the licensee and review of test records showed that IST testing requirements were followed; no discrepancy with the pump testing were identified. Also, the pumps' performance were within the pump head curves. The licensee revised the test procedure and performed the IST test for both pumps at the same pump speed. Consistent satisfactory pump data was obtained. This item is closed.

A non-cited violation was identified. No violations or deviations were identified.

3. Licensee Event Report (LER) Review (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to verify reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been, or will be, accomplished in accordance with Technical Specifications (TS). Based on this review, the following LERs were closed:

a. (Closed) LER 254/91024-LL: Failure of Carbon Dioxide Extinguishing System Due to Inadequate Flow Rates. Carbon dioxide concentration testing in the diesel generator rooms identified that the carbon dioxide fire suppression system did not meet required flow rates. Corrective actions included installation of larger flow nozzles, retesting with satisfactory results, and scheduling work to increase carbon dioxide injection time. Based on evaluation of licensee corrective actions, this item is closed.

b. (Closed) LER 265/92001-LL: Group I Isolation/thermal Expansion Scram for Actuation of MSL Low Pressure Switches Due to Pressure Fluctuations in Sensing Lines. This issue was discussed in Inspection Report 254/265-94004. Licensee corrective actions will be assessed during review of Inspector Follow-up Item 254/265-94004-02. This LER is closed.

c. (Closed) LER 265/92018-LL and L1: High Pressure Coolant Injection (HPCI) System Manually Isolated Due to an Inadequate Procedure. On May 29, 1992, in response to a "HPCI Pump Area High Temperature" alarm, the nuclear station operator (NSO) manually isolated the HPCI system in accordance with the alarm procedure. Investigation by the licensee identified the alarm to be spurious. No actual alarm condition was present. In response to the event the licensee revised the annunciator procedure to give clearer guidance on operator response to the annunciator. Review of the system logic showed that the alarm function operated as designed. This LER is closed.

d. (Closed) LER 254/92020-LL and L1: Technical Specification Containment Leakage Limit 0.6La Exceeded. During performance of local leak rate test (LLRT) procedure QTS-100-44, "Air Containment Atmosphere Dilution to Standby Gas Treatment," containment isolation valve 1-2599-5B leaked excessively. The cause of the excessive leakage was identified and repairs completed. This LER is closed.

No violations or deviations were identified.

4. 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 inspectors reviewed the events with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements, and that corrective actions would prevent future recurrence. The specific events are as follows:

March 28	Toxic gas analyzer pump inoperable due to pump seizure.
April 1	Unit 1 HPCI restricting orifice (63B) main steam trap to drain pot was found 95% clogged from welding slag.
April 12	Unit 2 EDG local/remote control switch found out of position.
April 16	A fire occurred in Unit 1 torus when welding leads contacted blasting grits.
April 17	Unit 2 reactor recirculation sample containment isolation valves 220-44 & 45 failed to close when operated from control room switch.
April 23	Loss of cooling fans on Unit 2 main transformer, forcing reactor down power.
April 25	Grit blasting hose spuriously energized and grit blasted a hole in the Unit 1 torus down-comer spherical junction.
May 11	Spill of diesel fuel oil outside the crib house.
May 11	Loss of security diesel resulted in loss of perimeter lighting.

a. Fire in Unit 1 Torus

On April 16, 1994, a welding machine was energized from outside the torus. The welding leads, located in the torus, made contact with blasting grit. The insulation around the welding leads overheated and ignited debris. The resultant smoke was visible to a confined space attendant. The attendant notified the control room of the fire. The machine was deenergized, and the fire was extinguished. The fire was contained to a small area, and did not damage plant equipment.

Work in the torus was suspended pending cleanup and completion of an investigation. The investigation revealed that the individuals did not inspect the welding leads prior to energizing the welding machine as required by the welding and burning permit. The individuals involved were counseled and disciplinary action was administered.

b. Loss of Unit 2 Main Transformer Cooling

On April 23, at 7:26 p.m., the Unit 2 main transformer trouble annunciator was received in the control room. An operator was dispatched and found all transformer cooling fans tripped. An immediate load drop was commenced in accordance with procedure. This initiated a 30-minute time clock to restore cooling fans or remove all load from the transformer. At 8:14 p.m., one fan bank was restored. Later during troubleshooting, the control relay was found shorted out on fan bank 2. The licensee temporarily hardwired the control relay to fan bank 2 for continuous operation and placed fan bank 1 in a cycling mode to accommodate the transformer heat load.

The system engineer indicated that the resistance drop of the long run of wire between the control room and the control power panel caused a low voltage condition. This caused the relay to chatter and burn up. This low voltage condition was a factor when power was secured to both fan banks. A modification to install another relay powered from a closer source was proposed.

Prior to the cooling fan failure the fans were turned off to perform a fire surveillance. The inspectors reviewed past records and identified four other similar events which were documented on problem identification forms (PIFs). None of the PIFs had been resolved by the required due date. The significance level of the PIFs varied and the PIFs had been assigned in all but one case to different people. None of the PIFs had been assigned to the cognizant system engineer. No one individual had been assigned to trend PIFs to identify recurring problems. The main transformer was not a safety related component, but loss of a main transformer posed a challenging transient to the plant. Better trending, corrective action, and management attention of the integrated reporting process (IRP) appeared warranted.

The immediate corrective action on the transformer was timely. However, guidelines for operational analysis department (OAD) personnel to work on plant equipment were not well understood by operators or plant personnel. Those guidelines were corrective actions from a previous transformer deluge event due to OAD maintenance. The inspectors will review the licensee's corrective actions in future inspections.

c. PIF Weaknesses

The inspectors identified other problems with PIF system tracking and follow-up. A failure of a safety related 125V DC battery charger to limit current was not documented in a PIF o. a work request until pressed by the inspectors. In addition, a PIF written for a reactor water cleanup (RWCU) temperature indication concern was closed without resolving the problem. The licensee did not document HPCI drain orifice clogging until several days after discovery. The PIF for HPCI drain orifice was not dispositioned in a timely manner due to delay in the PIF process and engineering review. Ten days passed before an operability evaluation was performed. These items in conjunction with severe backlog of overdue Level 3 and Level 4 PIFs indicated the need for increased management oversight.

No violations or deviations were identified.

5. 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.

Tours of accessible areas of the plant were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, excessive vibration, and to verify that equipment discrepancies were noted and being resolved by the licensee.

The inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection and physical security plan controls. The inspectors identified that housekeeping had declined during the period, including a failure of workers to clean up tools, improperly routed cords and hoses, and trash. Initial management efforts to correct the problem helped, but were not completely effective. Additional management intervention and tours had been called for by senior management to resolve the problem, and were still needed at the end of the period.

Plant operating performance was good during the period. Unit 1 was shutdown for refueling the entire period. Unit 2 remained at or near 97 percent power for most of the period, except for a transformer problem which forced a load reduction on April 23. Operator performance was good during several off-normal events, including feedwater regulating valve lockups and a main transformer fan failure.

a. Operations Inattention to Detail

Control room observations during the inspection period identified problems with attention to detail. The problems involved expired interim procedures and inadequate review of chart recorders.

- The inspectors found 6 of 20 safety related interim procedures (IPs) expired without being replaced by a permanent procedure. The IPs were used to implement a change to an established procedure. This presented a potential for operators to use previous versions of the procedure since the IPs had expired.

- Several control room and plant chart recorders were not adequately reviewed by operators. Examples included failures of operators to initial and date at prescribed time intervals, and failure to observe and correct recorders when the recorders were not inking properly.

The licensee reviewed all operations interim procedures which had expired and took steps to ensure that inappropriate actions were not taken prior to permanent procedures being implemented. The licensee initiated a review of the procedure change process to study methods to minimize delays in the process.

b. Licensed Operator Training

The training and operations department were proactive in operator training. The inspectors observed simulator requalification training involving dual unit events and the simulated manning of emergency facilities. The individuals responsible for manning such facilities were present for the turnover process in the simulator. This was the first time the training evolution was conducted using the simulator computers to simulate both units. Positive results were observed during the training evolution.

No violations or deviation were identified.

6. Monthly Maintenance Observation (62703)

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

Q12006	Disassemble, Realign and Reassemble 1D Condensate Pump
Q12010	Disassemble, Realign and Reassemble 1D Condensate Booster Pump
Q10018	Disassemble and Inspect Restricting Orifice

Q07783	Inspect & Perform QCMPM 1500-2 for 1 B & C RHRSW Room Sub Door
Q11331	Perform Environmental Qualification Surveillances on MCC 19-1

Unit 2

Q15878	Replace Solenoid Valve 2-0220-45
Q15934	Disassemble/Reassemble failed solenoid valve 2-0220-45

a. Unit 2B Residual Heat Removal (RHR) Room Cooler Inoperable

On March 16, 1994, electrical maintenance was authorized to inspect breaker G2 on Motor Control Center (MCC) 19-1. The inspection was performed in accordance with Quad Cities Electrical Maintenance Surveillance (QCEMS) 250-11, Attachment A, "Motor Control Center Cubicle Inspection." The out-of-service (OOS) document to support the work had tags hung on the breaker and the local control power switch. Breaker G2 provided alternate power to Unit 2B RHR room cooler fan. Breaker G2 and the control power switch were removed from the cabinet on March 17. Shortly thereafter, work on the breaker was stopped.

On April 8 an equipment operator attempted to start the 2B RHR room cooler fan. The fan did not start. Electrical maintenance determined that the fan would not start with breaker G2 removed from its cubicle. The breaker was reinstalled and the control power switch was rewired thus restoring power to the room cooler fan. A walkdown was performed of all Unit 1 essential equipment MCCs which had active OOSs associated with Unit 2 components to ensure that the Unit 2 components still had power. No discrepancies were identified.

The work on breaker G2 was released by operations with the understanding that the breaker was to be inspected in place. However, the procedure performed by maintenance required the breaker to be removed. The OOS requested by maintenance and authorized by operations had tags hung on breaker G2 and the control power switch. Workers moved the OOS tags to the front panel, as allowed by the procedure. The control switch wiring was determinated; subsequentlv, the breaker with the control power switch attached, was removed.

The control switch on the front of breaker G2 was wired into the breaker and provided a means of selecting normal or alternate power to the room cooler fan. By removing the breaker with the control switch attached, the fan was incapable of operating from either its normal or alternate power sources. The 2B RHR room cooler provided room cooling to the 2C and 2D RHR pumps. The licensee determined that the room cooler was unavailable for about 3 weeks. The licensee discovered on April 8 that the 1/2 EDG was inoperable a total of 103 hours during the period that the 2B RHR room cooler was unavailable. The licensee documented the event on LER 265/94-007 dated May 6, 1994.

The safety significance of this event was mitigated by a licensee analysis which determined forced cooling of the 2B RHR room would not be required during an accident condition. The room would not reach the environmental qualification temperatures assumed for equipment in the room for 10 hours.

This event was indicative of weak work control practices. The work package did not identify that removal of the breaker would render the 2B RHR room cooler inoperable. The operations staff was not cognizant of the extent of maintenance required by the procedure. The procedure allowed workers to move OOS cards from the breaker to the front panel. However, workers did not recognize that removing the OOS tag and determinating the switch changed the status of the 2B RHR room cooler. Maintenance personnel moved OOS tags from the control power switch on breaker G2 without verifying the isolation as proper for the work being performed. Quad Cities Administrative Procedure (QCAP) 307-11, Revision 1, "Preparation and Control of Safety, Regulatory, ASME Code or Reliability Related Maintenance Work Package," step D.9.b(1), stated, "If applicable, verify points of isolation listed on OOS are proper for work being performed." Failure to verify isolation points on breaker 2G resulted in inoperability of 2B RHR room cooler fan and is considered an example of a Violation (254/265-94010-01a(DRP)) of 10 CFR 50, Appendix B, Criterion V, "Instructions Drawings and Procedures."

b. Restricting Orifice in Unit 1 HPCI Plugged

The licensee developed preventive maintenance (PM) tasks to inspect selected restricting orifices in both unit HPCI pumps as a recommendation after a diaphragm rupture event on June 9, 1993. The licensee assigned these PM items a higher priority after a diaphragm rupture event at the LaSalle Station revealed that a blocked restricting orifice was a contributor.

On March 21, 1994, maintenance personnel intended to inspect restricting orifice 1-2301-63C. However, workers inadvertently disassembled restricting orifice 1-2301-63B instead. Upon disassembly, the 63B orifice was found almost fully clogged by welding slag. After evaluating the condition, the licensee reported the potential inoperability of Unit 1 HPCI on April 1. The clogged orifice could have made HPCI inoperable under certain accident scenarios had the unit been operational. The licensee disassembled restricting orifices for Unit 2 HPCI and reactor core isolation cooling (RCIC) pumps. The orifices were found in good condition.

The deficient condition was documented on a problem identification form (PIF 94-0719) 4 days after the condition was identified. The

PIF was forwarded to engineering on March 25 as a "concern screening." Concern screenings were expected to be completed in 3 days. Engineering completed the screening on March 31. Additionally, due to mis-communications, PIF 94-0833, which documented disassembly of the wrong orifice, was not written until April 4. The inspectors were concerned that the licensee's problem identification, operability evaluation, and reporting to the NRC were untimely.

10 CFR 50, Appendix B, Criterion V, required in part that activities affecting quality shall be accomplished in accordance with instructions. Quad Cities Administrative Procedure (QCAP) 307-12, "Preparation and Control of General Work Request," Revision 1, step D.11.b required workers to perform work as required by the work package. Work request Q10018 required work be performed on 1-2301-63C. Working on restricting orifice 1-2301-63B without required instruction which could have resulted in personnel injury or component inoperability is an example of a Violation (254/265 94010-01b(DRP)) of 10 CFR, Appendix B, Criterion V.

c. <u>RHR Service Water Vault Door Seal</u>

On March 21, 1994, operations authorized performance of QCMPM 1500-2, Rev 0, "RHR Service Water Submarine Door Preventive Maintenance" for the Unit 1 B/C RHR service water door. After the gasket was inspected and replaced, the mechanical maintenance workers informed engineering that the hatch required a local leak rate test (LLRT). Engineering intended to test the hatch at a later date. On March 27 during package closeout, the licensee found that a prerequisite sign-off for the shift engineer was not completed. Additionally, a limiting condition for operation (LCO) was not entered for the maintenance performed, and a LLRT was not completed. The LCO was entered after discovery of the condition. A local leak rate test of the vault door was completed satisfactorily and the LCO was exited on March 28.

The plant conditions established by operations to perform the door seal inspection did not require an entry into the LCO. However, when the door seal was replaced, the flood barrier should have been considered inoperable and the appropriate LCO entered. The Unit 1 B/C RHR service water room housed the shared emergency diesel generator (EDG) cooling water pump. Technical Specification 3.9.E.1 required that if the shared EDG becomes inoperable, the operating unit (Unit 2) must be shutdown within 7 days. The period of shared EDG inoperability did not exceed this 7-day period.

The inspectors were concerned that the failure to complete a prerequisite step in the maintenance procedure resulted in a missed identification of entry into the LCO. Engineering did not aggressively pursue the responsibility to perform a LLRT on the hatch after it was informed by the maintenance department. The inspectors considered these to be examples of work control weaknesses. Quad Cities Administrative Procedure (QCAP) 1100-12, "Procedure Use and Adherence Expectations," Revision 3, step D.6.b.(3), stated that correct usage of procedure includes ensuring applicable prerequisites were met. The failure to complete a prerequisite step in a maintenance procedure resulted in a missed LCO entry and is an examples of a Violation (254/265 94010-01c(DRP)) of 10 CFR 50, Appendix B, Criterion V.

d. Argon Release in Confined Area

On March 30, 1994, two welders were overcome by argon while welding inside the Unit 1 torus. The welders became lightheaded and required assistance to exit the torus. All torus work was stopped and personnel were evacuated. As a precaution, the two welders were taken to a hospital, but were soon released.

Argon was used to purge oxygen for pipe welding. The argon was released inside a tent set up in the torus. An air monitor was inside the tent and located under the welding area. When the air monitor alarmed, the two welders exited the area. It was determined that the increase in argon was due to the tent ventilation fan not operating. The confined space entry form required that forced ventilation be operated to support the job. A ventilation blower was connected to the tent, but the workers failed to operate it prior to starting their work. The licensee stopped the work until all individuals working the job were briefed on ventilation requirements. The inspectors will continue to follow the licensee's personnel safety practices in future inspection.

e. Refueling Outage

Unit 1 refueling outage (Q1R13) continued with problems in several areas. Refueling activities and control of the torus painting project were delayed due to numerous problems. The licensee reduced the overall scope of the outage twice because the planned scope was too large to effectively manage the outage. The reductions dropped about 46,000 man hours of work, and postponed jobs such as main steam isolation valve (MSIV) overhauls, RHR system valve replacements, RHR motor refurbishment, and condensate system repairs until Q1R14 in 1995.

Problems with the torus recoat project included: exceeding projected dose by over 300 percent; numerous personnel contamination events; two workers overcome by argon purge gas; a fire inside the torus; inadequate preparation for temporary ventilation hook-up; and poor control of blast hoses resulting in an unmanned blast hose grit-blasting a hole in a torus down comer spherical junction.

The licensee implemented a new overall project manager for the torus job and increased management attention to the torus work activities. This action appeared to improve planning and implementation for torus projects during the remainder of the period.

Refueling activities were performed well when the refuel bridge was operating properly. Numerous equipment problems with the Unit 1 bridge delayed fuel off load. Some of the problems were discovered as part of post modification testing for a modification performed just prior to the refueling outage. System engineer, maintenance, and vendor intervention eventually resolved most of the bridge problems, including some longstanding bridge deficiencies. The licensee continued efforts to ensure the bridge will be ready for the scheduled June 8 refueling.

f. Battery Charger Failure

On April 20, 1994, following a discharge test of the Number 1 125V DC battery, the DC breaker for the battery charger tripped. The system engineer determined the breaker trip was due to the high current output of the battery charger following a full battery discharge test combined with a current limiting card failure in the charger. The current limiting card should have prevented the output of the charger to about 200 amperes. The DC breaker tripped after operators observed the charger ammeter to be pegged high (greater than 300 amperes).

The inspectors discussed the problem with the system engineer and discovered that no work request or problem identification form (PIF) was written to document the failure or initiate corrective actions. The engineer planned to wait for a vendor inspection of the chargers following the Unit 1 refueling outage. Unit supervisors interviewed by the inspectors were unaware of problems with the Unit 1 charger. Other operators indicated that this problem was recurring.

The inspectors discussed with plant management the concern that since a PIF or work request was not initiated, this long standing problem was not addressed satisfactorily; and that no operability determination was made for the equipment. The licensee later initiated a PIF and work request to repair the charger. The licensee expressed concern that this failure to document and correct problems did not meet management expectations. At the end of the period, the licensee has not issued corrective work requests to investigate and repair potential problems with the other battery chargers. The inspectors will continue to follow engineering corrective actions in future inspection.

g. Personnel Safety

During the inspection period, plant workers' performance regarding personnel safety appeared weak. Although the inspectors identified numerous examples of safety weaknesses to the licensee, and several safety meetings were held with licensee personnel, numerous safety weaknesses, personnel injuries, careless work practices, and careless radiation protection practices continued. Personnel injuries included two workers overcome by Argon gas in a confined space, a second occurrence of a worker tripping over a cord and falling down steps, a worker in distress after losing air supply in a confined space, and a worker without a hard hat receiving head lacerations and stitches. Management stressed personnel safety and implemented programs in several areas to improve safety; however, positive results were not evident. A site management decision for workers in contaminated areas to wear hard hats where hazards existed was not yet implemented at the end of the inspection period. The inspectors will continue to monitor licensee efforts to improve personnel safety as an Inspector Follow-up Item (254/265-94010-02(DRP)).

One violation with three examples was identified. One inspector follow-up item regarding personnel safety was identified.

7. 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 0

QCOS 2900-1 Quarterly Safe Shutdown Makeup Pump Flow Rate Test

Unit 1

QTS 170-6 Functional Test of the Second Level Undervoltage

Unit 2

IP675 Quarterly RCIC Pump Operability Test
QCOS 202-12 Quarterly Testing Reactor Recirculation System Air Operated Valves
QCOS 2300-1 HPCI Pump Operability Test

a. Containment Isolation Valves

On April 17, 1994, operators performed Quad Cities Operating Surveillance (QCOS) 202-12, "Quarterly Testing Reactor Recirculation System Air Operated Valves" for Unit 2 recirculation sample Valves 220-44 and 220-45. Valve 220-44 did not close using the control room switch. After the switch was cycled, valve 220-44 indicated closed. Similarly, valve 220-45 did not close using the control room switch. The control switch was cycled 4 times before valve 220-45 indicated closed. Operators declared the valves inoperable, and closed the valves in accordance with TS 3.7.D.2. Operators also noted that the station computer received valve position information from the switch position and not from actual valve position.

Valves 220-44 and 45, containment isolation valves, were normally open, failed closed. The control room switch actuated a solenoid valve which directed air into (to open) or vented air from (to close) the diagram operated valves. On a Group I primary containment isolation system actuation, both valves should have closed in less than 5 seconds.

The licensee replaced the solenoid for the 220-45 valve. The removed solenoid was disassembled, but no problems were identified. The licensee intended to cycle the valves at an increased frequency to reduce stem-packing friction. This is considered an Inspector Follow-up Item (254/265 94010-03(DRP)) pending inspectors review of the licensees's activities to address the valve problems.

One inspector follow-up item was identified regarding reactor recirculation sample valves. No violations or deviations were identified.

8. <u>Engineering and Technical Support (71707)</u>

a. <u>Planning of Torus Work</u>

On March 28, 1994, the inspectors notified the control room that the Unit 1 torus temporary ventilation (TTV) was started by contractors without the required pre-evolution briefing. Upon request by the inspectors, the control room operators tested the ability to isolate the TTV. However, poor communications between the control room and TTV operator delayed the TTV test isolation for about 8 minutes.

A portion of TTV exhausted into reactor building ventilation ducting through isolation dampers and into an exhaust stack. Engineering later recognized that if a reactor building isolation signal occurred, with the TTV in operation, contamination could possibly spread inside the reactor building. In the temporary alteration, engineering did not specify times or methods to stop TTV to minimize the possible spread of contamination inside the reactor building.

The inspectors were concerned that contractor control was weak, since the required brief was not performed prior to TTV operation. To address communication weaknesses from the control room, a designated communicator was assigned to the TTV control panel to stop TTV when requested. Additionally, the licensee installed a temporary alteration to stop TTV upon a reactor building ventilation isolation signal.

The inspectors determined that project management of the torus recoat program was weak. Communications between departments necessary to support the torus recoat job were lacking. Concerns from each department were not solicited nor incorporated until after the TTV system was scheduled for use. Operators were not initially in control of the equipment tied into plant systems. The licensee then conducted meetings in which all departmental concerns for the torus recoat were solicited, and plans were developed to address those concerns. The addition of a full time torus recoat project manager also helped resolve the coordination and communication problems, and focused management attention to the problems.

b. EDG Local/Remote Switch Out of Position

On April 12, 1994, control room operators noted that the normally energized Unit 2 emergency diesel generator (EDG) stop light was extinguished. After troubleshooting, the licensee discovered that the local/remote switch on the local EDG control panel was over rotated beyond its "Remote" position to an unmarked position. The EDG was inoperable with the switch in the unmarked position. The switch was later correctly repositioned. The licensee completed a surveillance test on the Unit 2 EDG to ensure component operability. After an investigation, the licensee was unable to determine how the switch was mispositioned. Only two out of eight positions were used. Stop screws were not installed to restrict switch movement to those two positions. The Unit 1 and 1/2 EDG local/remote switches were positioned correctly, but were also missing stop screws.

The licensee's corrective actions were effective and timely. Actions included an inspection of similar switches to ensure that stop screws were installed and installation of stop screws in each of the three EDG local/remote switches. Operators demonstrated knowledge of the control panels and questioning attitudes.

No violations or deviations were identified.

9. Report Review

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

10. Regional Request (92701)

a. Agastat Time Delay Relays

The inspectors reviewed licensee response to a problem with Agastat time delay relays associated with the anticipated transient without scram (ATWS) surveillance test. At Dresden Station, one relay had failed to actuate and the other actuated outside the required time limit. With both relays failing the low reactor level ATWS trip, both recirculation pump field breakers would have failed to activate.

The problem was attributed to the service life of the relays. The service life was four and a half years for normally energized relays and ten years for normally de-energized relays. The licensee performed a review of ATWS and other systems that contained similar relays. All relays affected by the age related problem had surveillances to verify operability. A review of maintenance history found no significant failures had occurred. The licensee generated work requests to replace relays that were in operation longer than the recommended life for both Units 1 and 2. The Quad Cities' response to the issue was prompt and thorough. The inspectors had no further concerns.

b. Impact of Dresden Second Level Undervoltage Relay Problems

The inspectors reviewed an industry problem with undervoltage relays for applicability to Quad Cities. At Dresden Station, second level undervoltage relays were located in the reactor building. These relays were required to be environmentally qualified (EQ) due to radiation concerns. Because the harmonic filters (HFs) for the relays were not EQ, the HFs were removed. The HF's function was to filter distorted AC power signals. After the HFs were removed, the calibration AC power source had a slightly distorted power signal. This allowed a relay to be calibrated with a slightly different relay setting. The different relay setting error was non-conservative.

Quad Cities had undervoltage relays in radiation areas. However, the relays were tested each refuel outage and were environmentally qualified. All other technical specification required undervoltage relays contained required harmonic filters.

The licensee determined that some actions would be prudent to ensure proper relay operation and initiated the following corrective actions:

- Initiated work requests (WRs) to replace relays that have been in operation longer than 5 years (normally energized relays) and 10 years (normally de-energized relays). If duration of operation could not be determined, the licensee planned to replace the relays.

- Revised procedures and surveillances to incorporate testing the operation of the relays and replacement.

- Entered replacement frequency of the relay into General Surveillances (GSRV). The frequencies for normally energized and de-energized relays were every two and four refueling outages, respectively.

No violations or deviations were identified.

11. Licensee Identified Violations

The NRC uses the Notice of Violation as a standard method of 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,

- 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 violation of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued was discussed in paragraph 2.e.

12. Inspector Follow-up Items

Inspector follow-up items are matters which have been discussed with the licensee, will be reviewed by the inspectors, and which involved some action on the part of the NRC, licensee, or both. Inspector follow-up items disclosed during the inspection are discussed in paragraphs 6.g. and 7.a.

13. 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 May 11, 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.