

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No: 50-254/96011, 50-265/96011

Licensee: Commonwealth Edison Company (ComEd)

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

Location: 22710 206th Avenue North  
Cordova, IL 61242

Dates: July 13 - August 22, 1996

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## EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 & 2  
NRC Inspection Report 50-254/96011, 50-265/96011

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of inspection from July 13 - August 22, 1996, by resident staff and region-based inspectors; in addition, it includes the results of announced inspections by regional emergency preparedness inspectors and a NRR emergency preparedness specialist.

### Operations

- Control room operators conducted an orderly and error-free Unit 2 restart, with enhanced management and quality verification oversight (Section 01.2).
- Operations displayed conservative decision making by delaying Unit 2 startup activities until safety issues were addressed (Section 01.3).
- Equipment operators failed to reposition a condensate demineralizer drain valve during a return to service. The resulting condensate flow diversion had little affect on reactor parameters (Section 04.1).

### Maintenance

- The discovery of growth of zebra mussels in the suction strainers to both fire diesel pumps, resulted in the licensee declaring the fire protection system inoperable (Section M2.1).
- The licensee continued to have problems with safety-related equipment reliability which was linked to installation of improperly sized parts and poor control of vendor work practices (Section M2.2).
- Human errors and non-adherence to work instructions appeared to be indicative of some workers lacking a careful, questioning attitude (Section M4.1).

### Engineering

- Both the NRC and the licensee continued to evaluate a reactor water cleanup system high energy pipe break scenario (Section E1.1).
- Engineering identified improperly installed whip restraints on safety-related equipment. The whip restraints were repaired prior to unit startups (Section E2.1).
- Re-evaluation of NRC Information Notice 92-18 required the licensee to modify certain electrical circuits to ensure motor-operated valves would not be prone to damage by fire-induced shorts (Section E3.1).

- Inservice testing requirements had not been fulfilled for a high pressure coolant injection check valve (Section E3.2).

#### Plant Support

- A licensee task force identified weaknesses in work planning and management oversight of contractors, which resulted in significantly increased exposure during QIR14 (Section R1.1).
- Overall performance during the 1996 emergency preparedness exercise was very good. However, a few specific concerns were noted for followup at a later date.

## Report Details

### Summary of Plant Status

Unit 1 remained in refuel outage QIR14 throughout the inspection period. Unit 2 was shut down May 10, 1996, when operators removed the unit from service due to high winds which damaged plant structures. The licensee's resolution of emergent design issues affecting safety system operability continued to prolong the unit outages. Unit 2 reactor startup commenced on August 9; however, when pressure was increased to normal operating pressure, a leak was detected in the HPCI system discharge check valve. Operators shut down Unit 2 to effect valve repairs. Unit 2 was restarted on August 14 and synchronized to the grid on August 15.

### I. Operations

#### 01 Conduct of Operations<sup>1</sup>

##### 01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations.

During the inspection period, several events occurred which required prompt notification of the NRC pursuant to 10 CFR 50.72. The events and dates are listed below.

- August 11 Emergency Notification System (ENS) call. Unit 2 high pressure coolant injection (HPCI) was declared inoperable during startup due to a 14 gpm leak from the HPCI testable check valve.
- August 15 Operators synchronized and loaded Unit 2 main generator to the grid.
- August 16 ENS call. Unit 2 HPCI pipe jet impingement base plate "as-found" condition determined to have been incapable of resisting applied design loading. Licensee repaired deficient condition prior to Unit 2 startup.

The inspectors noted conservative decision making during startup of Unit 2 by both staff and management. However, there was an example of a human error during a return to service during the period.

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<sup>1</sup> Topical headings such as 01, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.



## 01.2 Unit 2 Startup Activities

### a. Inspection Scope (93702)

The inspectors observed Unit 2 startup activities. The inspectors reviewed licensee startup procedures, hold points, and attended pre-evolution briefs.

### b. Observations and Findings

During initial startup of Unit 2, operators detected a leaky valve bonnet which necessitated unit shutdown to effect repairs (Section M2.2.b.iii). Operations performance during initial startup, and subsequent restart of Unit 2, was error free. Communication, individual focus and attention to detail were evident in all operations that were observed by the inspectors. Pre-evolution briefs were conducted prior to shift turnover and before commencing significant evolutions. The briefs included discussion of trip and abort criteria, special precautions and adherence to procedures. Individuals were designated specific tasks to ensure critical attributes were observed. Briefings were thorough and shift turnover in the control room was conducted in an orderly manner. The startup activities were slow and conservative.

Operations management authorized each milestone of the startup by use of a "hold point" document. The hold point document ensured important tasks were completed prior to an increase in reactor power. The licensee provided round the clock overview of the startup with representatives from senior management, operations management, and site quality verification.

### c. Conclusions

The inspectors noted more management involvement and overview in startup activities. Use of administrative hold points ensured important milestones were completed prior to power increase. The startups observed by the inspectors were slow and conservative with good licensee oversight present in the control room.

## 01.3 Operational Decision Making

### a. Inspection Scope (71707)

The inspectors observed in-plant activities, spoke with operators and reviewed licensee documents and evaluations concerning problems encountered.

### b. Observations and Findings

#### i. Reactor Pressure Vessel Temperature Difference

After heat up of Unit 2, operators noted the indicated differential temperature between the steam dome and the reactor vessel bottom drain

was 151 degrees F. Licensee procedures stated this differential temperature was not to exceed 145 degrees F. Technical Specification 3.6.H.5 required this differential temperature be less than 145 degrees F for starting of a recirculation pump in an idled loop. Operators conservatively held reactor power steady until engineering evaluated the condition.

This differential temperature limitation was recently added as a result of engineering review of General Electric Service Information Letters (GE SILs). The temperature limit was implemented by SIL 251 and a supplement, but had not previously been incorporated into operating procedures. The SIL recommended limiting this differential temperature to avoid thermal stresses to control rod drive stub tubes as a result of thermal stratification in the bottom of the reactor vessel during low recirculation flow conditions.

Engineering evaluated the condition and concluded that the indicated temperature did not accurately reflect actual reactor vessel bottom head conditions. Engineering determined that partial blockage of the bottom head drain line was creating a low enough flow rate that significant cooling was occurring in the reactor effluent. The licensee planned to clean out this drain line during the upcoming refuel outage. In the interim, the indicated temperature will be used should TS 3.6.H.5 become effective. This is a conservative approach.

Operations resumed power ascension only after receiving Engineering's favorable technical assessment.

ii. Assessment of Breaker Test Device Condition

On August 9, 1996, operators commenced startup on Unit 2. With one control rod withdrawn, the electricians notified Operations of a disparity between digital and analog current readings on an electrical calibration test device. This could have led to setting the over current trip set points of some safety-related breakers in the non-conservative direction. Operations management discontinued the unit startup pending evaluation of the impact on plant safety. The licensee assessed the test device was within calibration specifications. Operations then recommenced Unit 2 startup activities.

c. Conclusions

In both cases, the inspector found Operations management had demonstrated conservative decision making by deciding to delay reactor startup until safety aspects of these issues were resolved.

### 03 Operations Procedures and Documentation

#### 03.1 Criticality Monitoring for New Fuel Vaults

##### a. Inspection Scope (71707)

The inspector reviewed information which NRC requested from licensees to determine how 10 CFR 70.24 requirements were being met.

##### b. Observations and Findings

Title 10 CFR 70.24 required licensees to have installed criticality monitoring systems in areas where special nuclear material is used or stored. This included requirements to have evacuation procedures and to conduct drills to familiarize personnel who work in the area with the evacuation plan. At the Quad Cities nuclear facility, this area included the new fuel storage vault. Prior to a refuel outage, the licensee temporarily stores new fuel in the vault.

The inspector found that the licensee did not have criticality monitors installed to purposely satisfy 10 CFR 70.24(a). However, the licensee did have area radiation monitors installed near the new fuel storage vault which provided an alarm in the control room. The licensee believed these alarms met the intent and specific wording of the rule. The licensee was evaluating the radiation monitors' response to a vault criticality event.

##### c. Conclusions

The inspectors consider this an **Unresolved Item (URI 50-254/265-96011-01)** pending review of the licensees's response to the issue.

### 04 Operator Knowledge and Performance

#### 04.1 Human Performance Error during Return to Service

##### a. Inspection Scope (71707)

The inspectors reviewed the licensee's investigation of errors made by operators during a return to service (RTS) of the condensate demineralizer system.

##### b. Observations and Findings

During a RTS of the Unit 2 "D" condensate demineralizer, two operators were required to position 2-5599-4 valve to the "closed" position. Both operators left the valve in the as-found (open) position. Several shifts later, one of the same operators failed to detect the errant valve position despite noting 100 gpm to 200 gpm flow when the test procedure required the operator to verify no flow. The operator later noted an improper system response when lining up the demineralizer.

About 3500 gallons per minute flowed into the demineralizer for about 15 seconds before the operator stopped the evolution and informed operations supervision. Several shifts later, operators found the "D" condensate demineralizer manual drain valve open instead of closed.

Unit 2 was operating at about 50 percent power when the condensate flow excursion occurred. The flow excursion had no effect on the feedwater flow or core parameters. Water drained from the condensate demineralizer entered into the backwash receiver tank (BRT). The BRT level increased but the tank was not overflowed.

As corrective actions, Operations reviewed 25 OOS and interviewed operators to determine how the return to service and out of service programs were being implemented. Operations management determined there was no widespread problem with the program implementation.

c. Conclusions

The inspectors concluded this problem was a human performance issue, not a program error. The operators believed they had returned the valve to the required position during the return to service. The inspectors were concerned by the multiple missed opportunities to identify this valve mispositioning error. Other human performance issues are documented in Section M4.1.

08. Miscellaneous Operations Issues (92700)

- 08.1 (Closed) LER 50-254/93001: High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Systems Declared Inoperable. The licensee determined TS surveillance requirements were missed for swap-over switch contacts and logic circuitry. Specifically, contaminated condensate storage tank (CCST) low water level and torus high water level HPCI/RCIC suction paths were not fully tested for both Units 1 and 2 HPCI and RCIC systems. This was previously addressed in Violation (VIO 50-254/265-93004-03). In addition, the HPCI torus suction check valves were discovered to be leaking.

In response, the licensee fully tested the suction source swap-over circuitry and repaired the HPCI torus suction check valves. A new procedure, QCOS 2300-11, "CCST/Torus Level Switch Refuel Outage Functional Test," was issued to test the swap-over circuitry. The RCIC and HPCI logic functional test procedures were also reviewed and enhanced to insure all logic paths were fully tested. In addition, the licensee added acceptance criteria to mechanical maintenance procedure QCMMS 2300-01, "HPCI Torus Suction Check Valve 1(2)-2301-39 Inspection," to verify by feeler gauge the check valve disc alignment. Functional testing of the check valve to ensure proper back seating was added to operating surveillance procedure QCOS 2300-16, "Quarterly HPCI Torus Suction Check Valve Closure Test." The inspectors reviewed the above corrective actions and concluded they were acceptable. This item is considered closed.

- 08.2 (Closed) LER 50-254/93003: Degraded Voltage Concern on Electrical Bus. The licensee identified a potential design deficiency concerning the low pressure coolant injection (LPCI) swing bus during degraded voltage conditions. The 480 volt swing bus supplies power to motor-operated LPCI valves. Sustained degraded voltage on the LPCI swing bus (and the associated 4 kV safety bus) could lead to the failure of both LPCI and Division II core spray low pressure sub-systems during a loss of coolant accident (LOCA) concurrent with a degraded voltage condition if the 4 kV feed breaker to the affected safety bus did not open. Only one division of core spray would be available to shut down the plant. However, this postulated event exceeded the current licensing basis.

During a LOCA event, the licensee indicated that based on realistic emergency core cooling models, the affected unit could be safely shut down on one core spray pump. The ComEd probability risk assessment group determined that the combined probability was in the order of  $1.2E-12$ . In addition, the licensee issued procedure QCOA 6500-13, "Failure of Division II Degraded Voltage Relay Protection Concurrent with a LOCA." The procedure provided instructions on how to manually transfer the LPCI swing bus to the redundant safety related power source during a degraded voltage condition. The inspectors reviewed the procedure and concluded that implementation would compensate for this design concern. This item is considered closed.

- 08.3 (Closed) LER 50-254/93015: Safe Shutdown Makeup Pump (SSMP) Compensatory Actions not Taken. With both units shut down, the licensee removed the SSMP from service for repairs. During the maintenance period, operators started up both units. The startup checklists did not include fire protection administrative requirements. With the units operating, operators were unaware that compensatory actions were required for the inoperable SSMP. This was a violation of 10 CFR 50, Appendix R. The inspectors consider this to be a **Non-Cited Violation (NCV 50-254/265-96011-02)** consistent with Section VII.B.1 of the NRC Enforcement Policy. The inspectors reviewed the licensee's corrective actions in the LER and noted improved licensee use of administrative procedures providing compensatory action for inoperable fire protection equipment. This item is closed.

## II. Maintenance

### M1 Conduct of Maintenance

#### M1.1 General

Maintenance continued to experience human errors due to a lack of questioning attitude by some maintenance personnel. Some equipment performance problems were linked to installation of improperly sized material.



## M2 Maintenance and Material Condition of Facilities and Equipment

### M2.1 Zebra Mussel Growth in Fire Pump Suctions

#### a. Inspection Scope

The inspectors reviewed a videotape inspection of the licensee's intake structure, spoke to fire protection engineers, and reviewed actions taken by the licensee to address the discovery of zebra mussels in the intake structure.

#### b. Observations and Findings

Divers inspecting the Unit 1 side of the intake structure identified the "A" fire pump suction strainer about 60 percent blocked by zebra mussel growth. The strainer was removed from the pump suction, cleaned, and reinstalled. The licensee documented the condition on PIF 96-2510 and generated an action plan to determine the extent of zebra mussel intrusion into the fire system.

The licensee performed an inspection of the "B" fire diesel suction and safety related intake bay. The inspection identified about 25 percent coverage of zebra mussels on the "B" fire diesel suction strainer. The interior of the safety-related intake walls had between 5 percent and 100 percent coverage of zebra mussels. Suction piping to the safety-related service water pumps had some zebra mussels present. The screens between the circulating water bays and the safety-related bay did not exhibit evidence of zebra mussel growth.

The licensee inspected various plant equipment in contact with river water systems, including fire system strainers, but did not identify any evidence of zebra mussels. However, exterior fire mains not having strainers were flushed. The flushes identified some loose shells, but passed the required flow rates.

In anticipation of biological growth on plant systems, the licensee had installed a biocide injection system some years ago. This system inhibited biological growth on the interior of circulating water and safety related cooling water systems. However, the biocide injection point did not preclude biological growth in the fire water systems.

The fire pumps were last operated and determined to be operable in early January, 1996. The licensee considered both diesel fire pumps to be inoperable from May 6 until the suction strainers were cleaned (August 9). This was based on temperature considerations affecting mussel growth. The licensee has other means of pressurizing the fire main but the equipment was not qualified for fire protection backup.

#### c. Conclusions

The period of licensee-determined inoperability included days when the system was required to be operable. A Licensee Event Report will be

filed on the issue. The inspectors consider this an **Unresolved Item** (URI 50-254/265-96011-03) pending further review of the licensee's investigation, evaluation and corrective actions to address zebra mussel fouling of the fire water system.

## M2.2 Equipment Performance Problems

### a. Inspection Scope (62703, 92701)

The inspectors reviewed licensee investigations, observed general maintenance practices, reviewed work packages, and spoke with workers. The inspectors reviewed work on the Unit 2 "A" control rod drive (CRD) pump, Unit 1 "D" residual heat removal service water pump (RHRSWP), and the Unit 2 HPCI testable check valve.

### b. Observations and Findings

#### i. Unit 2 "A" CRD Pump

The licensee historically has had problems with the CRD pumps. The inspector found that the 2A CRD pump had 7 major rebuilds in the last 10 years. Recently, the pump operated for only about 40 hours before being removed from service on May 17 due to high vibrations (PIF 96-1842).

The inspectors observed that the licensee carefully disassembled the 2A CRD pump and documented the interior condition of the pump. During reassembly, workers identified the rotor contained an incorrect metal. The second rotor, delivered from a vendor, was dimensionally incorrect. The licensee documented these deficiencies on PIFs. Worker practices observed by the inspectors were good. Workers payed careful attention to procedures, including foreign material exclusion (FME) requirements. Tools not in use were staged away from the pump. Materials designated for the inboard and outboard portions of the work were clearly separated. Upon completion of the overhaul, the pump was satisfactorily tested.

The investigation into the root cause of the failure was thorough. The licensee attributed past deficient maintenance practices as the cause of the pump failure. Specifically, improper measurements and installation of shims resulted in a loose rotor. This induced hydraulic instabilities, resulting in premature wear of pump internals.

#### ii. Unit 1 "D" RHRSWP Seal Leak

On August 8, operators noted the outboard seal on the 1 "D" RHRSWP had about an 8 gpm leak rate. Operators later declared the pump inoperable. During disassembly, maintenance workers identified mud in the outboard seal. The mud fouled the seal and caused the seal leak. The licensee last worked on the 1 "D" RHRSWP seal in September, 1993.

The workers also identified the shaft clearance at a bearing to be in excess of what was allowed by the vendor manual. Although not

associated with the seal leak, workers documented the condition in PIR 96-2594. The licensee believed the incorrectly sized shaft was installed in September 1993 before bearing fits were verified. Workers cleaned the seals, replaced the shaft, and operations successfully tested the pump.

iii. HPCI Testable Check Valve Leak During Unit 2 Startup

During Unit 2 startup with the main steam system at normal operating pressure, an operator, performing system walkdowns, identified a 14 gpm leak from the bonnet of the 2-2301-7 check valve. The licensee tightened the valve bonnet and reduced the leakage. However, operators shut down Unit 2 to allow disassembly and repair of the valve bonnet.

The valve was previously disassembled to check range of movement (See Section E3.2) during the outage. The licensee believed the leak was caused by improper reassembly. Specifically, the inner bonnet seal ring was slightly oversized. The valve vendor apparently forced the seal ring into the valve body during reassembly, which may have slightly cocked the seal ring. Subsequent torquing of the valve inner bonnet failed to adequately seat the seal ring. The licensee machined the inner bonnet face and replaced the seal ring with a properly sized seal ring. After reassembly, the valve was hydrostatically tested prior to starting up Unit 2.

c. Conclusions

The licensee continued to identify problems with safety-related equipment performance and reliability. In some instances, equipment performance problems were linked to installation of improperly sized parts. Recently, maintenance implemented a practice of measuring material prior to installation to ensure installed material was of the proper dimensions. The licensee planned to provide training to personnel responsible for working on rotating equipment this fall.

Additionally, unacceptable contractor work practices have contributed to equipment performance problems. The licensee decided to have maintenance supervision accompany vendors at the work site to ensure vendors employed acceptable work practices. However, more maintenance supervisors were needed before this plan could be implemented. The in-field work activities observed by the inspectors were disciplined and closely followed applicable procedures.

M2.3 Review of 4 kV Electrical Breaker Maintenance Practices

a. Inspection Scope

The inspectors assessed the licensee's response to the Dresden 3A LPCI 4 kV AMH type breaker failure. The inspectors reviewed the licensee's investigation results, discussed the Dresden breaker issue with ComEd personnel, and reviewed current breaker maintenance practices at Quad Cities.



b. Observations and Findings

ComEd determined that one of the primary causes for the Dresden failure was hardened grease in the trip latch roller bearing. Two spare 4 kV GE Magne-Blast circuit breakers, which had similar operating histories as the failed breakers, were sent to Dresden for analysis and refurbishment. The analysis determined that the Quad Cities breaker grease had not experienced the same severity of degradation and hardening as the grease from the Dresden breakers. The Quad Cities breaker grease still maintained adequate lubrication properties. This was attributed, in part, to Quad Cities maintenance practices. Breaker maintenance was being performed on the Quad Cities breakers about every 3 years vice 6 years at Dresden. In addition, Quad Cities maintenance practices included the oiling of applicable bearings and moveable parts with a light machine oil. The grease analysis indicated that the oil had penetrated the bearing areas and helped maintain the grease's lubricating properties.

A second concern involved replacement of the Tuf-Loc bushings. The bushing replacement was identified in a past GE Service Advice Letter (SAL). The licensee had replaced these bushings on some breakers. However, steps were added to procedure QCEPM 0200-01, "Inspection and Maintenance of 4 kV Horizontal Circuit Breakers Type 4.76-250," to address threading of the teflon bushing material and to replace the bushings if the breaker adjustment criterion could not be met. To date, the licensee had not experienced Tuf-Loc bushing threading problems.

The licensee refurbished 14 Unit 1 safety-related 4 kV breakers and had 6 scheduled for refurbishment. Unit 2 had 5 refurbished breakers and 13 scheduled for refurbishment. All of the breakers were within their preventive maintenance (PM) inspection frequency. The licensee indicated that during the upcoming unit outages, preventive maintenance items would be performed on all breakers and all breakers requiring refurbishment would be overhauled within 1 year. In addition, the licensee provided a list of nonsafety 4 kV breakers that were identified as having a technical specification required function. This population included reactor feed pump and recirculation pump motor-generator breakers on both Units. The six Unit 1 breakers had been refurbished and were scheduled to be inspected within their maintenance frequency. Four Unit 2 breakers had been refurbished and the remaining two were scheduled to be inspected during the upcoming Q2R14 refueling outage.

c. Conclusions

The inspectors reviewed procedure QCEPM 0200-01, 4 kV breaker SALs and the vendor manual, and determined that the licensee had incorporated applicable vendor information into the maintenance procedure. The inspector concluded that the licensee was addressing 4 kV breaker concerns in an acceptable manner.

## M2.4 Review of 480 Volt Electrical Breaker Maintenance Practices

### a. Inspection Scope

The inspectors reviewed the licensee's PM program for 480 volt circuit breakers.

### b. Observations and Findings

Maintenance Procedure No. QCEPM 0200-16, "Inspection and Maintenance of 480V AK-2-25 Breakers," was reviewed and the inspectors determined that the licensee had incorporated applicable vendor information into the maintenance procedure. All of the safety-related 480 volt breakers had been rebuilt when the new RMS-9 trip units were installed.

### c. Conclusions

A review of the PM list identified that all of the safety-related breakers were within their maintenance frequency. The inspectors concluded that the licensee addressed 480 volt breaker maintenance in an acceptable manner.

## M4 **Maintenance Staff Knowledge and Performance**

### M4.1 Human Performance Issues

#### a. Inspection Scope (62703)

The inspectors noted some human performance issues during the present and past inspection periods. The inspectors reviewed licensee investigations, observed work in the facility, and spoke to maintenance personnel.

#### b. Observations and Findings

##### i. Work Without an OOS in Place

On July 5, the licensee identified that a worker had commenced replacing belts on a ventilation fan for the laundry, tool, and decontamination (LTD) building without an OOS in place. The worker believed the standby out of service was still in existence and did not check the OOS prior to starting work. No injuries resulted from this nonsafety-related problem. The licensee documented this issue on PIF 96-2269.

##### ii. Wrong Unit Error

On July 10, a maintenance mechanic commenced disassembling a lubricating oiler from the Unit 2 emergency diesel generator cooling water pump (EDGCWP). However, the worker had an approved work package to work on the shared EDGCWP. The worker identified a tag on the Unit 2 EDGCWP

indicating the pump was the shared EDGCWP and started working on the wrong pump. The worker later identified he was working on the wrong component and reassembled the lubricating oiler.

The work did not require an OOS. The extent of work did not result in inoperable equipment and the safety of the worker was not in jeopardy. The supervisor directing the work was disciplined, and this event was discussed with maintenance personnel. The errant tag on the Unit 2 EDGCWP was replaced.

Work Package No. 950084164 required that workers replace a lubricating oiler on the shared EDGCWP. However, a worker commenced replacing an oiler on the Unit 2 EDGCWP instead. This is a Violation (VIO 50-254/265-96011-04a) of TS 6.2.A.1 since QCAP 306-00, "Work Execution," was not implemented. Step D.9 of QCAP 306-00 required work be performed in accordance with instructions.

iii. Low Pressure Coolant Injection (LPCI) Outboard Isolation Valve Breaker Maintenance Error

Operators previously removed the Unit 1 "A" train of LPCI from service to allow maintenance workers to modify breaker wiring in response to fire induced short circuits (hot shorts - see Section E3.1). Workers rewired the LPCI outboard isolation valve (1-1001-28A) motor operated valve power supply breaker. Quality control inspectors verified the wiring change was in accordance with the work instructions. However, during post maintenance testing, the breaker emitted smoke. The licensee later determined that the control power transformer was improperly wired during the work. The inspectors noted post maintenance testing identified the deficient condition prior to the system being declared operable. However, the deficient condition was not detected by the workers nor quality control. The licensee documented this condition on PIF 96-2434. The breaker was later repaired, satisfactorily tested, and declared operable.

Work Package No. 960066169-08 required that workers rewire the LPCI outboard isolation valve power supply breaker in accordance with instructions from Engineering, and that quality control inspectors verify the wiring. However, a worker miswired the power supply breaker and the quality control inspectors failed to identify the error. This is a Violation (VIO 50-254/265-96011-04b) of TS 6.2.A.1 since QCAP 306-00, "Work Execution," was not implemented. Step D.9 of QCAP 306-00 required work be performed in accordance with instructions.

c. Conclusions

Maintenance continued to experience human performance problems, with an additional example discussed in Section M8.8 below. Some of these work execution errors resulted in maintenance personnel not properly implementing established licensee programs. A careful, questioning attitude, promoted by licensee management, did not appear to be fully displayed by all of the work force.

**M7 Quality Assurance in Maintenance Activities**

**M7.1 Site Quality Verification (SQV) Audit of Materials Management - Licensee Self Assessment**

**a. Inspection Scope: (40500)**

The inspector attended an exit meeting of SQV's Audit of Materials Management (QAA 04-96-08) and reviewed the SQV Summary Report for this audit.

**b. Observations and Findings**

During the audit of materials, SQV documented two Corrective Action Requests (CAR's), nine PIFs, and two items in the SQV tracking system under the Emergent Issues List (EIL). The two (Level II) CARs identified problems with planned maintenance (either not performed or not documented) and the lack of an evaluation of parts for safety significance. Both of these findings had previously been documented in CARs from 1994. Additionally, the number of SQV identified problems was relatively high. SQV also identified lack of a formal means to self assess within the Material Controls Division.

**c. Conclusions**

The inspector concluded that the SQV audit was thorough. The number of deficiencies found by SQV revealed that self assessment within the Material Control Division was inadequate. The goal of station management was for each division to develop a fully functional self assessment capability. Effectiveness of departmental self assessments would be measured by key performance indicators.

**M8 Miscellaneous Maintenance Issues (92700)**

**M8.1 (Closed) LER 50-265/93024:** Reactor Scram During Surveillance Testing. A leaky instrument isolation valve led to a detector being inadvertently pressurized by maintenance technicians during a surveillance test. The instrument isolation valve seat was fouled with small particles of stainless steel. The licensee changed instrument surveillance tests to include leak testing instrument isolation valves prior to performing instrument surveillance tests. The inspectors reviewed the licensee's corrective actions. This item is closed.

**M8.2 (Closed) LER 50-265/94007:** Unit 2 "B" Residual Heat Removal (RHR) Room Cooler Found Inoperable. An operator identified the 2 "B" RHR room cooler fan would not start due to electricians removing the power supply breaker for maintenance. The issue was discussed in Inspection Report 50-254/265-94010 and determined to have been a violation. The inspectors reviewed the corrective actions and procedure changes incorporated from this event. This item is closed.

- M8.3 (Closed) Violation 50-254/265-94010-01a, 01b, and 01c: Three Examples of Errors Made by Maintenance Personnel. The first error was discussed in LER 50-265/94007 (see Section M8.2). The second part of the violation involved mechanical maintenance (MM) personnel disassembling the wrong orifice due to inadequate self checking techniques. The third part of the violation involved workers removing a residual heat removal service water vault door seal without authorization from operations. Additionally, required local leak rate testing was not performed in a timely manner. The inspectors reviewed the licensee's corrective actions for these events and consider the item closed.
- M8.4 (Closed) Unresolved Item (50-254/265-96008-03): Electrical Breaker Maintenance. This item was identical to the issue described in Section M2.3 and is considered closed.
- M8.5 (Closed) Inspector Followup Item (50-254/265-96008-04): Work Performed Without an OOS. This item was identical to the issue described in Section M4.1.b.i and is considered closed.
- M8.6 (Closed) Unresolved Item (50-254/265-96008-05): Work Performed on the Wrong Component. This item was identical to the issue described in Section M4.1.b.ii and is considered closed.
- M8.7 (Closed) Inspector Followup Item (50-254/265-96008-06): Control Rod Drive Pump Problems. This item was discussed in Section M2.2.b.i. This item is closed.
- M8.8 (Closed) Unresolved Item 50-254/265-96008-07: Work step not completed but documented as completed. Work Package #960015193-04 required, at step 23, that seal centering clips be removed and that set screws be tightened, as part of replacement of the 2C RHRSW pump. Failure to perform these steps is considered a Violation (VIO 50-254/265-96011-04C) of TS 6.2.A.1 since QCAP 306-00, "Work Execution" was not implemented. Specifically, step D.9 of QCAP 306-00 required work to be performed in accordance with instructions. The licensee's review of the foreman's performance in signing off the step, even though it was not done, determined this performance was unacceptable; the individual was fired. Based on the licensee's actions and the issuance of a Violation, the Unresolved Item is closed.

### III. Engineering

#### E1 Conduct of Engineering

##### E1.1 Reactor Water Clean Up (RWCU) Pipe Break Evaluation

###### a. Inspection Scope (37551)

The inspectors reviewed the licensee's evaluation, attended plant onsite review committee (PORC) meetings, and spoke with licensee management to determine if a particular event scenario involving a RWCU system pipe break could possibly affect secondary containment performance.



b. Observations and Findings

An event scenario identified at the Monticello nuclear power station was reviewed by the licensee for applicability at this station (PIF 96-2554). The scenario dealt with an undetected and unmitigated high energy line break (HELB) of 6 inch RWCU system piping.

Section 15.6.2 of the Quad Cities UFSAR analyzed a 1 inch line break inside secondary containment. This analysis determined that secondary containment integrity would not be compromised. However, the analysis did not appear to bound the RWCU HELB scenario.

The licensee's analysis of this event determined that a 6 inch HELB failure would be detected by room temperature, radiation detectors, and reactor building sump level. This type of failure could result in an automatic isolation of RWCU during some scenarios. However, in other scenarios, ComEd needed to rely on operator response to alarming conditions to mitigate the event since no automatic valve isolations would occur. The licensee's final response to this issue had not been received at the conclusion of this inspection period.

The inspectors consider this an **Unresolved Item** (URI 50-254/265-96011-05) pending completion of the licensee's evaluation, and NRC review.

c. Conclusions

The adequacy of the licensee's response to this issue will be assessed after it is formally submitted to the NRC.

E2 **Engineering Support of Facilities and Equipment\***

E2.1 Pipe Whip Restraints Found Installed Incorrectly

a. Inspection Scope

The inspectors reviewed the licensee's response to identification of improperly installed pipe whip restraints. The NRC obtained the engineering drawing and calculations for the temporary alteration to the Unit 2 HPCI jet impingement plate, 2-JIHP-3 for independent evaluation.

b. Observations and Findings

Maintenance personnel identified that three concrete expansion anchors (CEAs) on Unit 1 reactor coolant isolation cooling (RCIC) system piping were improperly installed. Specifically, three separate CEA bolts were found to have been tack welded to the base plate. One of the three CEAs was not actually installed in the concrete but was cut and welded to the baseplate. The licensee documented the deficient condition on a problem information form (PIF 96-2354).

ComEd determined the CEAs were installed in 1976 and knew the identity of the subcontractor who installed them. ComEd inspected every CEA

installed by the same subcontractor to determine if other CEAs were improperly installed. The licensee identified other whip restraint deficiencies affecting both units HPCI, RCIC, and Main Steam systems. Each deficiency was documented on PIFs. Engineering resolved each discrepancy prior to startup of the units.

The licensee identified a Unit 2 HPCI jet impingement plate (2-JIHP-3) as having a questionable mounting support. Engineering evaluated the "as-found" condition of the impingement plate as incapable of resisting applied design loading conditions. The licensee reported this degraded condition to the NRC via the ENS on August 16. Since the licensee could not qualify one of the two supports, another support was added prior to startup of Unit 2. The inspectors consider this an **Inspector Followup Item (IFI 50-254/265-96011-06)** pending NRC review of the licensee's evaluation of the temporary alteration to the HPCI jet impingement plate, 2-JIHP-3.

c. Conclusions

The licensee's decision to inspect all CEAs installed by the subcontractor, and to correct discrepant conditions prior to unit startup, was appropriate.

E2.2 Unit 2 4D Safety Valve Rupture Disk Found Ruptured

a. Inspection Scope

The inspectors spoke with the system engineer, reviewed the final safety analysis report (FSAR), and examined the licensee's evaluation of the as-found condition of the 4D safety valve.

b. Observations and Findings

On a Unit 2 drywell closeout inspection, the licensee discovered that the 4D safety valve rupture disk had ruptured. The rupture disk was a thin piece of stainless steel with a teflon liner mounted between the valve and the discharge to the drywell atmosphere. It was designed to blow out at approximately 10-15 psid. The UFSAR stated that if the temperature element (located on the leakoff line between the valve seat and the discharge) or the acoustic monitor failed to detect a leaking safety valve, then an inspection of the rupture disk would reveal it during an outage.

The system engineer reviewed safety valve temperatures, drywell sump temperatures, drywell atmosphere temperatures, reactor pressure, and average power range monitor (APRM) readings for approximately the past 6 months and concluded that the safety valve had not lifted and that no significant leakage past the valve seat had occurred. The system engineer had been aware of an interaction between operating the drywell equipment drain sump (DWEDS) pump in the recirculation mode and temperature fluctuations in the 4D (and 4G) safety valve leakoff lines. Periodically, when the DWEDS pump was run in the recirculation mode, the

safety valve leakoff line temperatures were observed to rise to 212 degrees F for some time before returning to normal (approximately 160 degrees F). The safety valve leakoff lines are routed to the DWEDS. The licensee walked down the leakoff lines and found that in some places the pipes had an upward slope which could allow water to be trapped in the low bends in the pipe. The system engineer thought the most likely cause of the rupture disk failure could be attributed to the trapped water being forced back towards the valve area when the DWEDS pump was run in the recirculation mode. Since the valve body would be hot, the water would flash to steam and could have enough force to blow out the rupture disk.

A work request had previously been written in 1995 to correct the slope of one of the safety valve leakoff lines. The system engineer planned to submit the work for the next refueling outage. The 4D safety valve was also scheduled for replacement during the next refueling outage.

c. Conclusions

No firm root cause of the rupture disk failure was found. However, no conclusive evidence was found that the rupture disk had failed due to the safety valve lifting or leaking. The system engineer thoroughly evaluated all pertinent data. The inspectors agreed with the licensee's conclusion that there appeared to be no immediate safety concern with the 4D safety valve.

E2.3 Safety-Related Battery Inspection

a. Inspection scope

The inspector interviewed the System Engineer responsible for safety-related batteries and the Seismic Engineer assigned to resolve seismic concerns on the batteries. The inspector also reviewed test documents and performed an independent inspection of the safety-related batteries following the licensee's corrective actions to resolve several deficiencies.

b. Observations and Findings

In July 1996 the licensee identified several seismic qualification concerns related to the safety related batteries. PIFs 96-2393 and 96-2408 were written to address the battery support structure contacting the battery cases in ways that might damage the battery cases during a seismic event. Additionally, it was noted that some Ethafoam spacers, designed to dampen shock and enforce a snug fit between the cells and the support racks, were not a tight fit between the horizontal members of the racks and the battery cells. The licensee determined that the batteries were in a condition that had not been evaluated and contracted a vendor to perform static and dynamic testing to resolve these concerns. Licensee personnel witnessed these tests at the vendor's facilities. The licensee determined that the tests were successful in certifying that the batteries meet seismic qualification. The vendor



issued a certificate of conformance to document the test results. The licensee completed the work to secure the foam spacers between the support racks and the battery cells. The system engineer performed a walkdown inspection to verify that the deficiencies were corrected.

c. Conclusions

Based on the inspector's interviews with licensee engineers, review of licensee documentation and a physical inspection of the batteries, the inspector concluded that the licensee's response and corrective actions concerning seismic qualification of the safety related batteries was adequate.

E3 Engineering Procedures and Documentation

E3.1 Fire Induced Electrical Short Circuits

a. Inspection Scope (73051)

The inspectors reviewed design packages and spoke to design engineers concerning the licensee's response to Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire."

b. Observations and Findings

The NRC issued IN 92-18 to notify the industry about an unanalyzed condition regarding fire protection and a plant's safe shutdown capability during a control room fire. This fire could cause short circuits between motor operated valve (MOV) control circuit conductors and their control power source (smart hot shorts). This could initiate spurious operation of certain MOVs prior to the operators shifting control of the valves to the remote/alternate shutdown panel. The IN identified that MOV torque and limit switches would not electrically disconnect the stroking valve. This could cause mechanical damage to the valve and/or damage to the motor due to the smart hot short bypassing the limit and torque switches. In many fire protection safe shutdown scenarios, the licensee took credit for manual manipulation of certain MOV's but did not consider that the valve could not be manually operated due to mechanical damage.

A contractor involved with Appendix R reviews at another utility believed the potential for hot short concerns may still exist since the motor thermal overload (TOL) protection may not protect the valve from mechanical damage. The Quad Cities design used motor TOL to protect the motor; however, in some instances the TOL tripping time had been increased to meet NRC Generic Letter No. 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," requirements. The licensee initiated a weak-link analysis and concluded that certain MOVs may be mechanically damaged prior to tripping the motor's TOL. This could prevent an operator from repositioning the valve if needed for an Appendix R fire scenario. Approximately 30 valves per unit were

modified to prevent this situation from occurring. The modifications did not change the electrical operation of the valves.

c. Conclusions

The inspectors reviewed several of the design packages and concluded that the design changes would alleviate the concern identified in the IN for these specific valves. However, weaknesses in the licensee's initial reviews in response to IN 92-18 including screening methodology and an incorrect determination that hot shorts were not a concern at Quad Cities, will continue to be tracked under a previously established Unresolved Item (URI 50-254/265-96008-11(DRS)).

E3.2 Inadequate In-Service Testing (IST) of the HPCI System Discharge Check Valve

a. Inspection Scope

The inspector observed troubleshooting of the Unit 2 HPCI discharge check valve (2-2301-7) when the valve failed to open and reviewed the licensee's preliminary root cause evaluation of the valve actuator failure.

b. Observations and Findings

The HPCI discharge check valve was required to open to allow HPCI flow into the feedwater line and to the reactor. The check valve, an active emergency core cooling system component, was required to be tested in accordance with the applicable ASME code and IST requirements. The check valve was equipped with a pneumatic operator for this purpose and was normally tested during cold shutdown. The operator was not required for the valve to function should the HPCI system be called upon to operate.

The valve was last tested satisfactorily in October 1995. The valve failed tests performed in May and June of 1996, but a SSMP test performed in July 1996, which partially opened the check valve, was completed successfully. Engineers suspected that the valve operator had failed but that the valve itself was functional.

During troubleshooting, maintenance mechanics removed the actuator and, based on vendor recommendations, attempted to open the valve using a torque wrench on the actuator rod. The valve would not open. Mechanics removed the valve bonnet and manually exercised the valve disc, which moved freely. Based on these facts, engineers concluded that the check valve would have functioned, but could not be exercised with the actuator. Several components on the actuator were found worn or deformed, including the hinge pin, disc pin and disc pin hole, and the valve packing. The disc pin hole was repaired and the other components were replaced. The valve was reassembled and tested.

During this troubleshooting effort, the system engineer noted that the valve actuator was designed to open the valve 30 degrees but that full open lift angle was 75 degrees. The Unit 1 HPCI discharge check valve had the same actuator. The system engineer confirmed this design with the vendor. The licensee planned to perform a modification to permanently remove the actuator and to perform the cold shutdown testing by using the torque wrench on the actuator rod to stroke the valve. This method would allow testing of the valve to the full open position, as required.

The licensee concluded that previous IST testing of the valve did not meet the requirement that the valve be tested to the full open position. Failure to properly test these valves was a violation of 10CFR50, 50.55a "Codes and Standards." This licensee identified and corrected violation is being treated as a **Non-Cited Violation (NCV 50-254/265-96011-07)** consistent with Section VII.B.I. of the NRC Enforcement Policy.

The licensee also contacted the vendor of other testable check valve actuators used at the site and confirmed that they were designed to fully open the valve.

c. Conclusions

The system engineer exhibited a good questioning attitude which led to the discovery that the HPCI discharge check valve had not been fully tested in the past. The IST program failed to recognize that the valve was not being fully tested. Although a final root cause for the valve actuator failure was not available at the end of the inspection period, the licensee determined that the check valve itself was functional. The inspector concluded that the licensee's long term plan to remove the actuator and manually test the valve was acceptable.

E3.3 Reactor Core Isolation Cooling (RCIC) Cable Separation Concern

a. Inspection Scope (73051)

The inspectors discussed the RCIC cable routing arrangement with site engineering and reviewed applicable design specifications.

b. Observations and Findings

The licensee identified in PIF 96-2298 that control circuits for RCIC containment isolation valves 1301-16 and 1301-17 were routed in cable trays which contained a mixture of nonsafety (non-divisional) and safety related cables. This appeared to deviate from typical primary containment isolation system (PCIS) divisional cable separation requirements. The licensee reviewed the original cable separation requirements (before Quad Cities committed to NRC Regulatory Guide 1.75 for new instrument loops installed after July 31, 1985) and concluded the cable routings met their original licensing basis.

Although the RCIC system was considered nonsafety, the two RCIC isolation valves were part of the safety related PCIS Group 5 isolation function. The non-divisional cables of concern provided RCIC equipment protection functions, such as a RCIC turbine trip on high reactor water level. Since these cables were considered non-divisional, their routing could be in any or all divisional cable trays. However, no redundant PCIS Group 5 isolation control circuits were run together. Each non-divisional cable contained, as a minimum, a positive DC power lead and a control logic lead, such as a return lead from a switch or relay contact. The negative DC lead was contained in a different cable. Since the DC system was ungrounded, a second cable failure to ground would have to occur to cause equipment failure. In addition, the licensee verified that if a non-divisional cable failed, operation of the PCIS function would not be prevented, and that if a valid PCIS Group 5 isolation signal was present, the valves would not spuriously open.

c. Conclusions

The inspectors reviewed the licensee's failure analysis and concluded that no single non-divisional cable failure, along with a divisional cable failure, would prevent the PCIS from performing its safety function.

E7 Quality Assurance in Engineering Activities

E7.1 Lubrication Program Corrective Actions

a. Inspection Scope (37551)

The inspector evaluated the licensee's lube oil sample and analysis program and interviewed the lube oil program coordinator. The inspector evaluated the effectiveness of the licensee's corrective actions to address the use of incorrect viscosity oil in safety related equipment.

b. Observations and Findings

Use of a reliable lube oil sample and analysis program is an effective tool in the assessment of equipment condition and reliability. The licensee documented several incidences of wrong oil applications in safety related equipment on PIFs.

The corrective actions for the cause of the original program problems, as well as lessons learned over the period, were implemented into a new lubrication program. This program included control of scheduling, sampling, analyzing, and documenting the results of oil samples. The administrative procedure incorporated the program controls and sampling activity into one procedure, simplifying the execution of the program. The new procedure illustrated how the licensee had taken additional measures to improve controls on the storage, issue, and handling of lube oil prior to its use.



c. Conclusions

The inspector's review of the number and nature of lubrication program related PIFs generated during the past year indicated improved performance results. The lubrication program was fully functional with only occasional problems identified. The inspector concluded that the licensee's corrective actions for the previous problems with the use of incorrect oil viscosities had been effective.

**E8 Miscellaneous Engineering Issues (92902)**

- E8.1 (Closed) LER 50-254/93002: Failure of Secondary Containment Test. The licensee determined a secondary containment test failed due to a procedural problem. The licensee determined secondary containment was operable at the time. The inspectors reviewed the licensee's corrective actions and reviewed QTS 160-5, "Secondary Containment Capability Test." This item is closed.
- E8.2 (Closed) LER 50-254/93012: High Pressure Coolant Injection Logic Failure due to Short Circuit. An operator, resetting HPCI trip logic, produced an electrical short circuit in a light socket resulting in HPCI becoming inoperable. The licensee installed a new model light circuit in Unit 1 and planned to install an identical model in Unit 2 during a later outage. The inspectors reviewed the licensee's corrective actions. This item is closed.
- E8.3 (Closed) LER 50-265/93013 and Rev 1: Reactor Scram from Fault on Unit 2 Main Transformer. Unit 2 automatically shut down from an internal fault of the Unit 2 main transformer. This fault also caused spurious equipment actuations. The licensee replaced the affected transformer. The inspectors verified the installation of a modification to prevent a spurious group 1 isolation of the PCIS following a turbine trip. Similarly, the licensee added a time delay relay in the feedwater regulating valve circuitry to prevent the valve from locking up after an automatic reactor shutdown. The inspectors consider both items closed.
- E8.4 (Closed) Inspector Followup Item (50-254/265-93019-03): High Pressure Coolant Injection System Logic Failure due to Short Circuit of Indicating Light. This item is identical to LER 50-254-93012 above. This item is closed.
- E8.5 (Closed) Violation 50-254/265-94005-06(DRP): The licensee failed to identify and revise feedwater flow calibration procedures per vendor manual and Service Information Letter No. 452, "Feedwater Flow Element Transmitter Calibration," Supplement 1, recommendations. As a result, engineering reviews did not ensure that vendor recommended static pressure adjustments for differential pressure transmitters were incorporated in the feedwater flow loop calibration procedure.

In response, the licensee calculated the transmitter static pressure shift and incorporated the results in procedure No. QCIPM 0600-01, "Reactor Feedwater Flow Loop Calibration." In addition, the licensee

developed a project work plan to review existing loop accuracy calculations and setpoint calculations to determine if static pressure uncertainties and applicable head corrections were correctly applied. The inspectors reviewed the above and concluded the licensee had addressed differential transmitter static pressure uncertainties in an acceptable manner. This item is considered closed.

- E8.6 (Open) Unresolved Item 50-254/265-95009-02: Failure of Unit 2 EDG to Operate. The inspector verified the licensee had implemented controls to store EDG air start motors to prevent moisture degradation of the carbon vanes. Subsequent successive monthly tests since November, 1995 have been successful, indicating that the starting problems had most likely been corrected.

The licensee's Management Action Plan described development of Root Cause Mentors and the implementation of a specific troubleshooting methodology. Progress to date has been slow. This item will remain

open pending the licensee's demonstration that their long range program goals and corrective actions have been implemented and are shown to be effective.

#### IV. Plant Support

##### R1 Radiological Protection and Chemistry Controls

##### R1.1 As Low as Reasonably Achievable (ALARA)

##### a. Inspection Scope (83750)

The inspectors reviewed the ALARA program for the current refueling outage (Q1R14) including ALARA initiatives, work scope and planning, station dose, outage performance, and the results of the Radiation Exposure Reduction Task Force (RERTF).

##### b. Observations and Findings

To date, accrued station dose was 950 rem, which was about 250 rem higher than projected. Contributing to the additional dose was considerable emergent work, outage scope additions and hydrogen addition effects, as described in Inspection Report 50-254/265-96006. Most of this additional dose was accrued during the Unit 1 refueling outage (Q1R14).

The licensee formed the RERTF to determine the causes for the higher than anticipated exposure and to provide recommended corrective actions. The RERTF reviewed four major areas: work management; radiation protection practices and radiological engineering; source term management; and reactor material integrity.

The RERTF identified the following major findings:

- Management was partially ineffective in planning the outage work scope, as the actual outage tasks performed nearly doubled the original scope and significantly increased overall dose. The increased scope was comprised of a combination of known work and emergent work. The known work was not appropriately identified. Emergent work could not be specifically identified, but could be reasonably addressed given previous station and industry experience.
- Deficiencies in the work planning and control process prevented the licensee from foreseeing the expected dose. In some cases, this prevented better ALARA planning which would have lowered the overall dose.
- Although the majority of the dose was from contracted work, contractor personnel were not involved in the planning process. Also, the number of contractors was not adequately controlled nor was appropriate station management oversight provided.

The RERTF findings were similar to NRC conclusions regarding overall outage planning and performance which were documented in Inspection Reports 50-254/265-96004 and 50-254/265-96006.

c. Conclusions

The RERTF identified weaknesses in work planning and control processes and management oversight of contractors. These resulted in significant increased exposure during Q1R14. These findings were consistent with those of the inspectors. The licensee was evaluating the results of the RERTF and planned to take appropriate corrective actions for the planning of the 1997 Unit 2 refueling outage.

R1.2 Implementation of the Radiological Environmental Monitoring Program (REMP)

a. Inspection Scope (84750)

The inspectors reviewed the REMP, including the 1995 Annual Radiological Environmental Operating Report, and a recent SQV audit of the REMP program.

b. Observations and Findings

The REMP sample collections and analyses were conducted in accordance with the ODCM. Environmental sample results indicated that there was no discernable radiological impact on the environment from the operation of the plant. The land use census was conducted as required, and documentation of the sample collection program was very good. All

deviations were noted in the annual reports. The SQV audit found no outstanding problems and indicated the implementation of the REMP was satisfactory.

c. Conclusions

Overall, the REMP was effectively implemented and well managed.

R1.3 Personnel Internal and External Dosimetry Programs

a. Inspection Scope (83750)

The inspectors reviewed the licensee's internal and external dosimetry programs including the calibrations and quality control programs for the licensee's whole body counting (WBC) and the implementation of the thermoluminescent dosimetry (TLD) program. Additionally, the inspectors reviewed the licensee's investigations and calculations of internal exposures.

b. Observations and Findings

The licensee maintained station accreditation with the National Voluntary Laboratory Accreditation Program and had maintained an effective quality control (QC) program. Interlaboratory comparisons indicated that the licensee's ability to process TLDs was good.

The licensee used whole body counting (WBC) and alarming portal contamination monitors to detect radioactive intakes. The inspectors reviewed several internal dose calculations and determined the calculation methodology used was conservative in assigning doses from inhalation and ingestion of radioactive material. The WBC calibration methodology was evaluated and was technically sound. Also, the calibration results and QC for the WBC were found to be properly performed.

c. Conclusions

The inspectors concluded that the licensee's external and internal dosimetry programs were effectively implemented. The licensee performed conservative internal dose assessments, technically sound WBC calibrations, and implemented good QC.

R6 Radiation Protection and Chemistry Organization Administration

R6.1 Radiation Protection Management and Staffing

During this inspection it was noted that the radiation protection technician and technician supervisory positions were stable, but there had been considerable turnover in the health physics department professional staff. The turnover had been the result of personnel leaving the company, department transfers, and management organization changes to strengthen the staff. At the conclusion of this reporting



period, it appeared that the turnover had not resulted in any obvious degradation of department performance.

**R8 Miscellaneous Radiation Protection Issues**

**R8.1 (Open) Inspector Followup Item (50-254/265-96004-10(DRS)):**

Identification of poor radworker practices by a ComEd task force, the development of long term corrective actions to correct these practices, and their effectiveness in preventing recurrence. In addition to the actions taken to prevent recurrence as identified in Inspection Report No. 50-254/265-96004-10, long term actions were still being developed during this inspection. In general, radiation work practices through June, 1996, have shown an improving trend. Training in problem areas, increased management oversight of work, and increased emphasis on personnel accountability have continued. This IFI will remain open until the long term corrective actions have been effective in correction of the identified problems.

**P3 EP Procedures and Documentation**

**P3.1 Review of Exercise Objectives and Scenario (82302)**

The inspectors reviewed the 1996 exercise objectives and scenario which arrived in sufficient time before the exercise to permit NRC review. The scenario provided an appropriate framework for the exercise and the objectives were appropriately demonstrated in the facilities evaluated by the inspectors.

**P4 Staff Knowledge and Performance in Emergency Preparedness**

**P4.1 1996 Evaluated Biennial Emergency Exercise**

**a. Inspection Scope (82301)**

The inspectors evaluated licensee performance in the following emergency response facilities during the 1996 evaluated emergency exercise:

- Control Room Simulator
- Technical Support Center (TSC)
- Operational Support Center (OSC)
- Corporate Emergency Operations Facility (CEOF)
- Emergency Operations Facility (EOF)

**b. Observations and Findings**

The simulator control room crew was professional and effective communications among the crew included repeat-backs and acknowledgements. The unit supervisor and operators were focused and provided a well coordinated response throughout the exercise. Control room briefings were conducted frequently during the day with clear communications between the crew.

The Shift Engineer (SE) quickly recognized and declared the Unusual Event (UE). Although the SE rapidly declared the UE, he mistakenly selected the wrong emergency action level (EAL) for the classification. Inappropriate EAL selection by the SE will be tracked as an **Inspection Followup Item (IFI 254/265-96011-08(DRS))**, pending NRC review of the licensee's corrective actions.

Initial notifications were made to the State and local authorities within 15 minutes for the UE and Alert emergency classifications. Responsibility for initial NRC notification was inappropriately delayed and transferred to the TSC. Subsequent NRC notifications from other facilities were made in a timely manner for the duration of the exercise. The untimely initial NRC notification will be tracked as an **Inspection Followup Item (IFI 254/265-96011-09(DRS))**, pending NRC review of the licensee's corrective actions.

TSC activation was rapid and efficient. The inspector observed thorough, detailed, and effective technical discussions and evaluations which addressed in-plant problems. One discussion included the need to obtain local control of the electromatic relief valves.

Status boards were well maintained with current information and reactor parameters. Priorities were established, posted, and modified as conditions changed. A television system displayed TSC priorities in the OSC.

The Station Director provided periodic, comprehensive briefings and kept the staff updated on emergency developments. Laminated copies of the EAL chart were available at many locations in the TSC. These EAL charts were used effectively to declare the Site Area Emergency (SAE). The staff proactively considered which changes in plant emergency conditions would require upgrading the emergency classifications. Performance in the TSC was effective and added to the licensee's overall response to the emergency.

The licensee activated the OSC in an coordinated, timely, and efficient manner with a sufficient number of people. The inspector observed numerous communications with other facilities including the TSC. OSC field teams were coordinated well and understood their task and associated priority. The inspector observed OSC managers consider plant environmental conditions prior to OSC field team assignments. Because of this the inspector noted that a field team was recalled due to a change in plant environmental conditions.

The OSC emergency response teams generally performed their assignments well, although the inspectors noted some exceptions. One instance was observed when a response team failed to take radiation survey readings upon returning from the field. This appeared to demonstrate a possible lack of awareness by the participant.

CEOF staff were prestaged in a nearby conference room and activation and staffing were not evaluated. Command and control transfers to and from

the CEOF were orderly, clear and timely. Inspectors observed efforts to ensure the manager assuming command and control adequately understood degraded conditions, current priorities, assigned responsibilities and current action items during the briefings and other communications.

The Emergency Planner did an excellent job of maintaining status boards within the CEOF's Emergency management Center (EMC) room. This included good organization for numerous information categories that were kept updated in a timely and accurate manner.

The Corporate Manager of Emergency Operations (CMEO) demonstrated good knowledge of the licensee's emergency plan and provided concise briefings to the CEOF staff. The CMEO effectively used the CEOF's communications systems to perform periodic briefings. In one instance, the CMEO initiated a conference call with Illinois and Iowa officials and clearly informed them of the bases of the SAE declaration. The CMEO also answered the States' questions in an appropriate manner. Overall performance in the CEOF was excellent.

The EOF staff had been prestaged at a nearby hotel and were released in a staggered manner to simulate actual activation. The EOF staff quickly and efficiently established contact with their counterparts in the TSC and prepared to assume response functions. The MEO proactively communicated directly with the States of Illinois and Iowa by phone to inform them of the transfer of command and control and to discuss the accident situation and plant status. The EOF technical staff provided indepth awareness of plant conditions and made frequent reference to the EAL matrix in anticipation of possible escalation of the emergency classification. The Advisory Support Director (the SRO from the station) was the only Quad Cities technical person in the EOF. He provide invaluable assistance to the EOF staff in interpreting plant data and conditions.

Numerous, diverse dose projections were performed to anticipate possible changes in plant conditions. After the EOF took responsibility for coordination of the offsite environmental monitoring teams, radio communications difficulties were encountered. The environs communicator efficiently and smoothly transferred control of the environs teams back to the TSC and continued to monitor all radio communications.

The inspectors observed the protective measures group perform indepth and wide ranging discussions related to emergency and plant conditions. Also, the environs group provided continual input to the facility managers related to on and offsite radiation dose rates. Protective actions were promptly and accurately recommended to the EOF managers.

Facility critiques immediately following the exercise termination were adequate. Critiques in the EOF, OSC and TSC had minimal response by the non-manager participants. Discussions with the licensee identified certain facility critiques were controlled by mostly managers and controllers and in some cases were not very self critical.

The inspectors identified exercise control problems with control room simulator fidelity problems. These simulator problems included unanticipated annunciator alarms, insufficient recirculation pump seal leakage indications, failure of the sump pump to operate from the control room simulator, and unanticipated feedwater oscillations. Also, the controllers did not observe some of the crew manipulations including the reactor scram process. These simulator problems coupled with the failure of the controllers observe and promptly correct the simulator problems created confusion in the control room simulator. The simulator problems and the failure of the controllers to promptly correct these problems will be tracked as an Inspection Followup Item (IFI 254/265-96011-10(DRS)), pending NRC review of the licensee's corrective actions.

c. Conclusions

The exercise was successful and demonstrated that the onsite emergency plans are adequate and the licensee is capable of implementing them. Overall exercise performance was very good. The Control Room crew's performance was professional and communications were effective. Technical Support Center staff rapidly evaluated plant conditions and made an appropriate emergency classification upgrade. Command and control and offsite communications in the Emergency Operations Facility were performed well. Three Inspection Followup Items were identified related to the untimely initial NRC notification made from the control room, the incorrect emergency action level used in the control room for the Unusual Event declaration, and the simulator fidelity problems coupled with the controllers delayed correction of the simulator problems.

**P8 Miscellaneous EP Issues**

**P8.1 Inspection Followup Items**

- a. Closed Inspection Followup Item (IFI No. 50-254/265-94015-01(DRSS)). Related to communications problems during the transfer of command and control between the CEOF and EOF and radiological release information flow problems. During the 1996 exercise communications between the CEOF and EOF were very good and radiological release information was communicated well. This item is closed.
- b. Closed Exercise Weakness (IFI No. 50-254/265-94015-02(DRSS)). Related to the failure to notify the offsite authorities of a radiological release in a timely manner. During the 1996 exercise radiological release notifications were made to the offsite authorities in a timely manner. This item is closed.
- c. Closed Inspection Followup Item (IFI No. 50-254/265-94015-03(DRSS)). Related to the failure of the protective measures group in the EOF to provide timely recommendations to assist with protective action decisions. During the 1996 exercise the EOF protective measures group provided timely recommendations for protective action decisions to be developed. This item is closed.

## V. Management Meetings

### X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management identified below at the conclusion of the inspection on August 23, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

#### ComEd

D. Cook, Operations Manager  
J. Garrity, Engineering  
J. Hoeller, Independent Safety Engineering Supervisor  
C. Peterson, Regulatory Affairs Manager  
F. Tsakares, Radiation/Chemistry Superintendent  
M. Wayland, Maintenance Superintendent

### INSPECTION PROCEDURES USED

IP 37551: On Site Engineering  
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems  
IP 62703: Maintenance Observation  
IP 62707: Maintenance Observation  
IP 64704: Fire Protection Program  
IP 71707: Plant Operations  
IP 73051: Inservice Inspection - Review of Program  
IP 73753: Inservice Inspection  
IP 82301: Exercises  
IP 82302: Exercise Objectives  
IP 83729: Occupational Exposure During Extended Outages  
IP 83750: Occupational Exposure  
IP 92700: Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities  
IP 92902: Followup - Engineering  
IP 92903: Followup - Maintenance  
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors



## ITEMS OPENED, CLOSED, AND DISCUSSED

### Opened

50-254/265-96011-01	URI	criticality monitoring for new fuel vaults
50-254/265-96011-02	NCV	SSMP compensatory actions not taken
50-254/265-96011-03	URI	zebra mussel growth in fire pump suctions
50-254/265-96011-04a	VIO	failure to follow procedure
50-254/265-96011-04b	VIO	failure to follow procedure
50-254/265-96011-04c	VIO	failure to follow procedure
50-254/265-96011-05	URI	RWCU pipe break evaluation
50-254/265-96011-06	IFI	pipe whip restraints found installed incorrectly
50-254/265-96011-07	NCV	inadequate in-service testing of the HPCI system discharge check valve
50-254/265-96011-08	IFI	selection of appropriate EAL a concern during 1996 exercise
50-254/265-96011-09	IFI	initial NRC notification was a concern during 1996 exercise
50-254/265-96011-10	IFI	simulator fidelity was a concern during 1996 exercise

### Closed

50-254/93001	LER	HPCI and RCIC systems declared inoperable
50-254/93003	LER	degraded voltage concern on bus
50-254/93015	LER	SSMP compensatory actions not taken
50-265/93024	LER	reactor scram during surveillance testing
50-265/94007	LER	Unit 2 "B" RHR room cooler found inoperable
50-254/265-94010-01a, 01b, and 01c	VIO	three examples of errors made by maintenance personnel
50-254/265-96008-03	URI	electrical breaker maintenance practices
50-254/265-96008-04	IFI	work performed without an OOS
50-254/265-96008-05	URI	work performed on the wrong component
50-254/265-96008-06	IFI	control rod drive pump problems
50-254/265-96008-07	URI	work step not completed/documented as required
50-254/93002	LER	failure of secondary containment test
50-254/93012	LER	HPCI logic failure due to short circuit
50-265/93013 and Rev. 1	LER	reactor scram from fault on Unit 2 main transformer
50-254/265-93019-03	IFI	HPCI logic failure due to short circuit of indicating light
50-254/265-94005-06	VIO	failure to identify and revise feedwater flow calibration procedures per vendor manual
50-254/265-94015-01	IFI	communications problems during exercise
50-254/265-94015-02	IFI	notification problem during exercise
50-254/265-94015-03	IFI	protective measures problem during exercise

### Discussed

50-254/265-95009-02	URI	failure of EDG to Operate
50-254/265-96004-10	IFI	identification of poor radworker practices by a ComEd task force

## LIST OF ACRONYMS USED

ALARA	-	As Low As Reasonably Achievable
APRM	-	Average Power Range Monitor
BRT	-	Backwash Receiver Tank
CAR	-	Corrective Action Requests
CCST	-	Contaminated Condensate Storage Tank
CEA	-	Concrete Expansion Anchors
CFR	-	Code of Federal Regulations
CRD	-	Control Rod Drive
DWEDS	-	Drywell Equipment Drain Sump
EBDG	-	Emergency Diesel Generator
EDGCWP	-	Emergency Diesel Generator Cooling Water Pump
EIL	-	Emergent Issues List
ENS	-	Emergency Notification System
FME	-	Foreign Material Exclusion
FSAR	-	Final Safety Analysis Report
GE	-	General Electric
HELB	-	High Energy Line Break
HPCI	-	High Pressure Coolant Injection System
IDNS	-	Illinois Department of Nuclear Safety
IN	-	Information Notice
IST	-	In-service Testing
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LPCI	-	Low Pressure Coolant Injection Mode of RHRs
LTD	-	Laundry, Tool, and Decontamination
MM	-	Mechanical Maintenance
MOV	-	Motor Operated Valve
OOS	-	Out of Service
PCIS	-	Primary Containment Isolation System
PDR	-	Public Document Room
PIF	-	Problem Identification Form
PM	-	Preventive Maintenance
PORC	-	Plant Onsite Review Committee
QC	-	Quality Control
RCIC	-	Reactor Core Isolation Cooling System
RERTF	-	Radiation Exposure Reduction Task Force
REMP	-	Radiological Environmental Monitoring Program
RHR	-	Residual Heat Removal
RHRSWP	-	Residual Heat Removal Service Water Pump
RTS	-	Return to Service
RWCU	-	Reactor Water Clean Up
SAL	-	Service Advice Letter
SIL	-	Service Information Letter
SQV	-	Site Quality Verification
SSMP	-	Safe Shutdown Makeup Pump
TLD	-	Thermoluminescent Dosimetry
TOL	-	Thermal Overload
TS	-	Technical Specification
WBC	-	Whole Body Counting