U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Commonwealth Edison Company (ComEd)
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	May 6 through June 16, 1997
Inspectors:	L. Collins, Resident Inspector K. Walton, Resident Inspector R. Ganser, Illinois Department of Nuclear Safety
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EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/97008(DRP), 50-265/97008(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

Major activities such as the Unit 2 refueling and startup were performed in a controlled manner and essentially error free. Less significant evolutions were not always planned as carefully and occasionally resulted in unexpected events or challenges to operators.

Operators inappropriately used the discrete component operation process to perform alternate system lineups for the fuel pool cooling system, drywell floor drain system, and the feedwater system during unit shutdowns.

Maintenance and Surveillance

The inspectors identified, through a sampling of emergency diesel generator (EDG) surveillance procedures, where the EDG surveillance program did not meet either the Technical Specification (TS) and/or the design basis documents. There was also one example where the test methodology was not adequate to determine the sealing capability of a check valve in the starting air system for the EDG.

Maintenance workers performed tasks safely and according to procedures. The successful repair of the reactor core isolation cooling (RCIC) system steam supply valve was well planned.

The inspectors reviewed and observed several logic functional tests on Unit 2. The tests were satisfactorily performed. The inspectors observed minor deficiencies including one pretest brief where the test director was unprepared and a maintenance error in which a jumper was placed in the wrong location.

Engineering

The inspectors identified an inadequacy with an abnormal operating procedure for the high pressure coolant injection (HPCI) system. The procedure did not include a reference for manually engaging the turning gear if necessary after an HPCI turbine trip.

Plant Support

As low as reasonably achievable (ALARA) initiatives during the Unit 2 refuel outage helped to reduce overall station dose to date. Radiation protection tracking and trending of dose was improved over previous refuel outages and allowed the mid-year revision to the dose goal. The 1997 station dose goal was revised from 1260 rem to 720 rem.

- The failure to take appropriate corrective action in response to identified zebra mussel growth in 1995 resulted in both fire pumps becoming inoperable in 1996 due to clogged suction strainers.

Report Details

Summary of Plant Status

Unit 1 entered the inspection period at full power. On May 16 a load drop was performed to repair a leak on the RCIC system steam supply valve. Following repairs to the RCIC valve, load was increased to full power and remained at or near full power throughout the inspection period.

Unit 2 was shut down for refueling outage Q2R14 on February 28, 1997. The reactor was restarted on June 8 and was shut down on June 10 to repair a degraded seal condition on the 2B recirculation system pump. The unit remained shut down at the end of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Observation of Significant Operations Evolutions

a. Inspection Scope (71707)

During the period the inspectors observed major refueling outage activities for Unit 2. The inspectors watched reactor refueling operations from the control room and refueling bridge, toured the drywell prior to final closeout, and observed startup activities including reactor criticality, power increase, and shutdown to repair the 2B recirculation pump seal.

b. Observations and Findings

Refueling began May 7 in accordance with Quad Cities Fuel Handling Procedure 0100-01, "Master Refueling Procedure." The inspectors verified that operators were in constant communication, recorded temperatures on an hourly basis, and performed required checks of source range monitor (SRM) response. Operators on the refueling bridge used three independent checks versus the required two when loading fuel assemblies into the reactor.

The inspectors conducted a drywell inspection near the end of the Unit 2 refueling outage. Drywell general material condition and housekeeping was good, notably better than at the end of previous outages. The inspectors identified a large amount of test wiring, previously used to transmit test data from main steam relief valves. The licensee subsequently removed this wiring. A small amount of work remained to be completed prior to final closeout inspections by the licensee.

During Unit 2 reactor vessel leak testing prior to startup and during startup activities, the inspectors attended several "heightened level of awareness" briefings. The briefings were well coordinated and included all participating departments. Procedures were discussed and task responsibilities assigned. The inspectors observed full participation from operators and noted clear communication with respect to potential problems, abort criteria, and expected results.

Unit 2 startup activities were carefully conducted and essentially error free. Noted anomalies included a single control rod drift into the core from the fully withdrawn position and the abnormal response of the 2B recirculation pump seal pressures. Operators promptly noted the problems and took appropriate actions. The Unit 2 reactor was subsequently shut down on June 10 to replace the recirculation pump seal.

On several occasions operators encountered an unexpected plant response during fairly standard evolutions. Twice a control rod drive pump tripped after starting, and once during a reactor protection system (RPS) power supply swap for Unit 2 a full reactor trip occurred. In all of these cases, plant configuration was different than expected and operator actions resulted in an unanticipated response. The control rod drive (CRD) pumps tripped on low suction pressure and the reactor trip occurred because the RPS shorting links were installed during the power supply swap. Management attributed the problems to a breakdown in scheduling and planning during the outage and took actions to ensure that all operations' activities were carefully reviewed prior to execution. The inspectors noted that no further anomalies of this type occurred.

c. Conclusions

Major activities such as refueling and startup continued to be carefully planned and controlled. Operator performance during these evolutions was essentially error free. Problems with schedule control resulted in an unexpected plant response on a few occasions. No adverse consequences resulted, and corrective actions were taken to prevent further events.

O1.2 Both Standby Gas Treatment Trains Inoperable During Testing

a. Inspection Scope (71707, 93702)

The inspectors reviewed the shift engineer's logbook and spoke with operations personnel concerning the standby gas treatment (SBGT) system inoperability.

b. Observations and Findings

During the performance of Quad Cities Operating Surveillance Procedure 1600-13, "Refueling Outage PCI [Primary Containment Isolation] Groups 2 and 3 Isolation Test," on May 4, 1997, operators inadvertently rendered both SBGT trains inoperable. On May 5 the shift engineer determined that the condition was reportable in accordance with 10 CFR 50.72 and initiated Problem Information Form (PIF) 97-2156.

The SBGT system consisted of an A train and a B train, with the A train control switch normally in standby and the B train control switch in primary. The SBGT system logic automatically starts the primary train when an initiation signal is received. If the primary train failed, the standby train would start after a 25 second time delay. To test this function, the B train was taken to the off position and the A train was placed in standby. An initiation signal was simulated, but the A train failed to start after the 25 second delay.

Earlier in the test a maintenance error caused a fuse to blow. Test personnel recognized the error and proceeded to replace the blown fuse, but inadvertently reinstalled the bad fuse. This blown fuse in the logic would have prevented the A train from automatically starting when in standby. The error in reinstalling the bad fuse was not recognized until the test continued and the A train did not start. The blown fuse was replaced. During this time the operators recognized that Unit 1 was in a limiting condition for operation (LCO) in accordance with TS 3.7.P.2, but did not recognize that the event was reportable under 10 CFR 50.72(b)(2)(iii) as the occurrence of any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material. This condition existed from 8:35 p.m. to 9:15 p.m. central standard time on May 4, 1997. During this period both trains were capable of manual start but not automatic start.

The next day the inspectors questioned the day shift engineer about the event and required reporting and found that the shift engineer was already reviewing the circumstances surrounding the event. The shift engineer concluded that the event was reportable and an emergency notification system (ENS) call was made on May 5, 1997. Failure to report this condition within 4 hours of discovery was a violation of 10 CFR 50.72. This licensee-identified and corrected violation is being treated as a **Non-cited Violation (50-254/265-97008-01)** consistent with Section VIII.B.I of the NRC Enforcement Policy. The inspectors reviewed the licensee's corrective actions, which included a review of this event and reportability requirements with licensed reactor operators.

c. <u>Conclusions</u>

The inspectors concluded that the safety significance of this event was low since either train could have been manually started. However, the failure to recognize a reportable event was a concern. The licensee's corrective actions addressed the inspectors' concern with accurately identifying reportable occurrences.

O3 Operations Procedures and Documentation

O3.1 Use of Discrete Component Operations

a. Inspection Scope (71707)

The inspectors reviewed the use of discrete component operations (DCOs) and a set of completed DCOs from April 1997. The inspectors discussed the use of DCOs with management.

b. Observations and Findings

Quad Cities Administrative Procedure 0230-06, "Discrete Component Operation," provided guidance for the operation of individual components where other procedural guidance did not exist. A DCO was defined as a set of actions necessary to operate a system component. The use of a DCO was not limited to one component, since more than one component may require operation to support the activity. The DCO process required that a request form be filled out with appropriate action steps approved by the unit supervisor. The procedure stated that a DCO was utilized when a component required operation for testing, such as troubleshooting or post maintenance test verification (PMTV), or as part of a maintenance activity such as an uncoupled pump run or, in other situations, at the unit supervisor's discretion. The DCO was approved by two individuals, a reactor operator or knowledgeable management person, and the unit supervisor.

The inspectors reviewed the following examples of the DCO process:

- Operators used a DCO to align the Unit 2 drywell floor drain sump (DWFDS) discharge to the floor drain collector tank rather than the normal lineup to the waste collector tank. As a result of drywell activities during the outage, the DWFDS water was not suitable for reprocessing, and operators needed to route the water to the floor drain collector tank. No procedure existed for changing the lineup, and the DCO was generated on April 3, 1997. This path was used until the system was realigned to the normal configuration on May 5, 1997.

- Operators used a DCO during the refueling outage on Unit 2 to alter the fuel pool cooling pump discharge valve lineup in order to throttle flow to the reactor cavity while continuing to discharge to the fuel pool. A procedure existed (Quad Cities Operating Procedure [QCOP] 1900-20) and could have been utilized with only minor changes to perform the required evolution.

- Another DCO was used to control reactor water level for Unit 1 during a shutdown when the reactor water cleanup system was not available to reject water. This DCO directed operators to isolate leakage past the feedwater low flow valve while the reactor water cleanup (RWCU) system was shut down and to open the valves as necessary to add water to the reactor vessel.

In all three examples discussed above, operators used DCOs to perform infrequent but necessary tasks. Each case involved an alternate system lineup and was not a "component" operation. No adverse consequences resulted; however, the use of DCOs rather than reviewed and approved procedures for operational activities was a concern.

The inspectors questioned operations management about the use of DCOs. A third party review of the use of DCOs had previously identified issues regarding potential improper use and lack of review. As a result the licensee had begun a monthly review of DCOs and had discovered issues that were similar to the inspectors' findings. The licensee was aware of the examples discussed above and was pursuing corrective action. At the end of the inspection period, operations' management had relayed examples of inappropriate use of the DCO process to all of the operating crews and had included the appropriate methods for controlling the activities (i.e., procedure field change, out of service, etc.).

c. Conclusions

The inspectors found that on several occasions DCOs were used improperly. The use of DCOs instead of reviewed and approved procedures for operational activities could result in unexpected challenges or plant response. However, the problems were previously identified, and the licensee had initiated corrective action.

O5 Operator Training and Qualification (IP 71707)

O5.1 Operator Training Observations

a. Inspection Scope

The inspectors observed all or portions of the following training activities:

- Two classroom sessions of initial licensed training (ILT), including the oxygen sampling and containment emergency venting systems

- Licensed operator requalification (LOR) classroom session on safe shutdown makeup system

- Two simulator sessions including "anticipated transient without scram" (ATWS) and "recirculation pump run-up," and A post scenario critique following the simulator session for ATWS.

b. Observations and Findings

The ILT class was fast paced and concentrated. The instructor was clear and precise and closely followed the lesson plan. The inspectors noted that information concerning containment emergency venting, in the event of a loss of coolant accident, included clear instruction on the requirement for timely notification of outside agencies.

During simulator training, in one scenario, the shift technical advisor (STA) was located in the simulator control room at the start of the scenario. When in the plant, the STA is generally stationed outside the control room. The inspectors questioned whether it would have been more realistic for the STA function to remain outside the simulator control room until the scenario warranted STA participation. The person in the role of the STA stated that the normal practice was for the STA to remain outside the simulator control room until required to enter by the simulated training event, and that this was an exception to what was the normal practice. The post scenario critique, following the simulator sessions, was interactive and constructive.

c. Conclusions

In the areas observed instructors were well prepared and trainees were interactive in the training effort. Operations management demonstrated an active interest in assessing and improving the level of training effectiveness.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) (50-254/93014): Intermediate Range Monitor 11 and Average Power Range Monitor 3 Both Bypassed Without ½ Scram Being Inserted. The LER stated that the cause was the failure to perform a self check. The inspectors verified that all corrective actions were completed and noted an increased use of self check and decreased number of errors since this event occurred. This item is closed.

O8.2 (Closed) Unresolved Item (50-254;265/94016-03): Reactor Vessel Draining Evolution. Quad Cities Administrative Procedure 260-3, Revision 2, "Screening for Potential to Drain the Vessel," considered that a motor operated valve (MOV) closeable from the control room provided sufficient isolation to prevent inadvertent drain down of the reactor vessel. The inspectors verified that the licensee has since revised the procedure (Revision 5) which credits automatic isolation on low reactor water level to prevent drain down. This item is closed.

O8.3 (Closed) Violation (50-254;265/96004-01a&b): Out of Service Errors Render the ½ EDG Inoperable and Result in an Engineered Safety Features System Actuation. The licensee counseled individuals involved in these events and added information to diesel generator procedures to describe the impact of removing certain fuses. The inspectors noted a decline in out of service errors since these events occurred in 1996. This item is closed.

O8.4 (Closed) Licensee Event Report (50-265/97009): Both Trains of SBGT Inoperable Due to Fuse Replacement Error. See Section O1.2. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance Observations

a. Inspection Scope

The inspectors observed/reviewed all or portions of the following surveillances.

QCIPM 0756-03	Local Power Range Monitor (LPRM) Calibration
QCIS 0200-28	Calibration ATWS High Pressure and Low Level Instruments
QCCP 0600-07	Determination of Sodium Pentaborate Concentration in Standby Liquid Control System
QTS 0170-07	Functional Test of the Second Level Undervoltage (Bus 23-1)
QCTS 0300-07	Functional Testing of the ATWS Recirculation Pump Trip and Alternate Rod Insertion (ARI) Logic
QCTS 0300-04	High Pressure Coolant Injection Logic Functional Test
QCTS 0920-15	Strongest Control Rod Withdraw Subcritical Check
QCIS 0500-03	Instrument RPS Scram Response Time Test
QCTS 0300-07	(IP 97-0076), ATWS Recirculation Pump Test and ARI Logic
QCTS 300-03	RCIC Logic Functional Test
QCTS 0310-03	Unit 2 Emergency Core Spray System Simulated Automatic Actuation and Diesel Generator Auto-Start Surveillance

b. Observations and Findings

During a pretest brief the inspectors noted, in one case, the test director did not appear to be fully knowledgeable of the details of the test. However, questions generated during the brief were answered by the test director prior to commencing with the test.

At one point during Quad Cities Technical Surveillance (QCTS) 300-03, RCIC Logic Functional Test, the inspectors observed that test technicians were confused about the location of a push button. Subsequently, the test was stopped until the correct switch location was identified. The test was again stopped when a jumper was placed on a wrong relay causing a ground condition and concurrent alarms in the control room. Problem Identification Form 97-2277 was written to address this problem. The licensee found that there was conflicting labeling on a relay resulting from past relay swaps without subsequent removal of old labeling. The evolution had been successfully performed in the previous fuel cycle with no known problems. The electrical drawing had been changed to reflect the new configuration, so when the test director walked-down the test, he observed the correct labeling on the correct relay. There were no panel layout drawings to show precise locations of relays in this panel. The test director performed a thorough walkdown to ensure that there were no other labeling problems. Following this, the test was successfully completed without further incident.

The inspectors observed key portions of the emergency core cooling system (ECCS) logic functional test, QCTS 0310-03. Operators conducted a final briefing prior to initiation of the test. Contingencies were reviewed for critical steps so that operators were certain of what action to take if the expected automatic action did not occur. Command and control was good. Each operator was given an assigned task and was thoroughly familiar with the actions required. The test was completed satisfactorily.

c. Conclusions

The inspectors reviewed and observed several logic functional tests on Unit 2. The tests were satisfactorily performed. The inspectors observed minor deficiencies including one pretest brief where the test director was unprepared and a maintenance error in which a jumper was placed in the wrong location.

M1.2 Maintenance Observations

a. Inspection Scope

The inspectors observed the following maintenance activities:

- Post maintenance testing of the Unit 2 reactor protection system uninterruptible power supply,
- Overhaul of the 2A CRD pump in maintenance shop,
- Licensee's activities concerning a RCIC steam valve leak,
- Emergency Diesel Generator Air Start Motor Replacement,
- Modify and Install Bus 24-1 Cubicle 8 for New Breakers, and
- Replace Merlin Gerin Breaker Auxiliary Switches.

b. Observations and Findings

The inspector observed electrical maintenance technicians perform post maintenance testing on the Unit 2 RPS uninterruptible power supply (UPS) following a periodic maintenance inspection. Workers performed voltage measurements to ensure UPS setup was in accordance with the procedure. The inspectors observed that workers observed proper safety precautions, communicated effectively, and carefully followed procedures.

Work observed on the 2A CRD pump consisted of mechanical maintenance department (MMD) personnel and a vendor representative in the process of measuring and stacking the rotating segments of the multi stage pump onto the shaft. This procedure required numerous trial setups. Workers carefully recorded measurements and safely handled the sections of the pump assembly. No discrepancies were observed in this activity.

The Unit 1 RCIC system outboard steam supply valve, 1-1301-17, had developed a steam leak around the seal ring. The licensee had been monitoring the steam leak and, based on its progression, developed a plan to repair the valve during reduced power operations to limit radiation exposure to personnel. Through a good planning effort and effective teamwork, the licensee successfully completed the repair work with dose exposure levels below those projected.

c. Conclusions

Maintenance workers performed tasks safely and according to plant procedures. The licensee effectively monitored the RCIC steam supply valve leakage. This resulted in a timely and well planned repair effort. The licensee's effort to plan and effect repairs resulted in successful repair of the valve leak with minimum dose exposure to workers.

M3 Maintenance Procedures and Documentation

M3.1 Emergency Diesel Generator Surveillance Procedures

a. Inspection Scope (61726)

The inspectors reviewed the below listed EDG surveillance procedures to determine if the requirements of Sections 8.3, 9.5.4, 9.5.5, and 9.5.6 of the Updated Final Safety Analysis Report (UFSAR) and the applicable portions of 3/4.9.A of the TS were properly addressed. The inspectors also reviewed the surveillance procedures to verify that the applicable TS bases were addressed.

- QCOS 6600-01 "Diesel Generator Monthly Load Test," Revision 15
- QCOS 6600-02 "Diesel Generator Air Compressor Operability," Revision 9
- QCOS 6600-03 "Diesel Fuel Oil Pump Monthly Operability," Revision 2
- QCOS 6600-05 "Quarterly Diesel Generator Fuel Oil Transfer Pump Flow Rate Test," Revision 6

- QTS 0310-06 "Emergency Diesel Generator Protective Trip Auto-Start Bypass Surveillance," Revision 3

- Interim Procedure 97-0080 "DG [diesel generator] Trip & Alarm Switches Cal., Protective Trip Bypass & Functional Test"

The inspectors also reviewed procedure QCOS 6600-02, along with drawing M-25, and Interim Procedure 97-0080, along with drawing 4E-1350A (sheets 1 and 2), to determine if the testing methodology described in the procedures was acceptable.

b. Observations and Findings

The inspectors' review of the above procedures, applicable portions of the TS, and the UFSAR identified the following:

QCOS 6600-01, "Diesel Generator Monthly Load Test"

Step G.1 (performance acceptance criteria) states that the generator voltage was 3900 to 4580 volts. The TS requirement for voltage, as stated in 4.9.A.2.c, was 4160 volts plus or minus 420 volts (3740-4580 volts). The voltage acceptance criteria in surveillance procedure QCOS 6600-01 was more than the TS requirements (3900 versus 3740). Discussion with the system engineer determined that the acceptance criteria was administratively controlled to 3900 volts to ensure the EDG would maintain voltage above degraded voltage criteria in TS 3.2.B-1.6.b (3845 volts-Unit 1 and 3833 volts-Unit 2).

Section 8.3.1.8 of the UFSAR, Analysis of Station Voltages, states that the minimum running voltage for the 4160 kV bus would be 3840 volts. The UFSAR further states that upon an undervoltage condition where the undervoltage relays actuate, the incoming line breakers trip, load shedding of the 4160 kV busses initiate, and the associated EDG starts and the EDG output breaker closes when the voltage and frequency from the EDG become satisfactory. At present the TS requirements for EDG voltage differs from the UFSAR analysis for degraded voltage. Even though the licensee is administratively controlling the minimum voltage during the monthly surveillance in QCOS 6600-01, Revision 15, a TS amendment would be necessary to establish acceptance criteria that would be in agreement with the design basis. This issue is an **Inspector Followup Item (50-254/265-97008-02)** pending submittal of a TS amendment to revise the EDG voltage acceptance criteria to agree with the design basis.

Technical Specification basis 3/4.9, page B3/4.9-3, states that the periodic surveillance requirements also verify that without the aid of the refill compressor, sufficient air start capacity for each EDG is available. The basis further states that with either pair of air receiver tanks at minimum specified pressure, there is sufficient air in the tanks to start the EDG. Procedure QCOS 6600-01, Revision 15, does not require that the air compressors be off and the air tanks at minimum specified pressure (230 psig). This is considered an **Unresolved Item (50-254/265-97008-03)** pending further discussion with the NRR technical staff.

QCOS 6600-02, "Diesel Generator Air Compressor Operability"

Each EDG has two banks of starting air with each bank consisting of a pair of air receiving tanks (A and B or C and D) and associated valves, and one starting air compressor. One of the purposes of QCOS 6600-02, Revision 9, is to verify that the check valves on the discharge header for each pair of air receiver tanks will close and seal as required by the licensee's IST program. The test methodology to verify the discharge check valve for air banks A and B will close and seal consisted of the following:

1) Isolate the C and D air receiver tanks.

2) Close the discharge valve for the air compressor associated with banks A and B and placing the air compressor control switch in pull-to-lock (PTL).

3) Bleed down banks A and B to 225 to 230 psig and record the final pressure.

4) Unisolate the C and D air receiver tanks.

5) After five minutes record the pressure for air receiver tanks A and B.

6) Calculate the change in air receiver pressure in tank A and tank B from the start of the test to the air pressure after five minutes. If the air pressure has increased 15 psig or more, than the check valve on the discharge header for tanks A and B had not sealed properly.

The inspectors had a concern with the above testing methodology. The air receiver pressure would be maintained from 230 to 250 psig with the TS minimum air pressure requirements being 230 psig. Therefore, if:

- the air pressure in air receiver tanks C and D during the start of the surveillance test for the check valve for air receiver tanks A and B was the minimum 230 psig, and

- the pressure in air receiver tanks A and B at the start of the test (Step 2) was 225 psig,

the acceptance criteria of less than 15 psig would be met even though the discharge check valve for tanks A and B could be improperly sealed. The inspectors consider QCOS 6600-02, Revision 9, not appropriate to ensure that the check valves on the EDG air receiver tanks seal in the closed direction. This failure to have an appropriate procedure is considered a **Violation (50-254/265-97008-04)** of 10 CFR Part 50, Appendix B, Criterion V.

Interim Procedure 97-0080, "DG Trip & Alarm Switches Cal., Protective Trip Bypass & Functional Test"

The inspectors reviewed drawing 4E-1350A, sheets 1 and 2, and Interim Procedure 97-0080 to determine if the testing methodology for ensuring that the protective high crankcase pressure trip was bypassed on auto starts of the EDG, as required by TS (4.9.A.8.g). The inspectors determined that the testing methodology adequately verified that all the necessary contacts required to change state for bypassing the high crankcase pressure trip were tested.

c. Conclusions

The inspectors identified, through a sampling of EDG surveillance procedures, several examples where the EDG surveillance program did not meet either the TS and/or the design basis documents. There was also one example where the test methodology was not adequate to determine the sealing capability of a check valve in the starting air system for the EDG

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Licensee Event Report (LER) 50-254/97010: "B" Control Room Ventilation System (CRVS) Inoperable Due to Freon Leak. On April 7, 1997, the licensee identified a Freon leak from "B" CRVS and declared the system inoperable. The licensee determined the failure occurred due to vibration-induced fatigue and replaced the damaged pipe. The licensee planned to assess the compressor/ condenser skid for vibration. The inspectors reviewed the licensee's corrective actions and consider this LER to be closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Inadequate High Pressure Coolant Injection System Procedure

The inspectors identified a problem concerning procedure QCOA 2300-04, HPCI Auto Trip. The high pressure coolant injection (HPCI) system control circuitry was designed to automatically start and engage the HPCI turning gear on a coast down following a trip of the HPCI turbine. There was a design flaw in the turning gear engagement mechanism whereby an engagement failure could occur in the rare occurrence of engagement gear abutment. According to the system engineer, the vendor has acknowledged this problem and has developed a modification to fix the problem. The licensee has not installed this modification in the HPCI system for either unit. The licensee developed procedure QCOA 2300-08, Turning Gear Failure to Start on a Coast Down, Revision 4, dated November 4, 1996, to ensure engagement of the turning gear. The procedure for "normal" HPCI shutdown under routine test conditions, QCOP 2300-04, HPCI System Shutdown, directs operators to use procedure QCOA 2300-08, should the turning gear fail to engage. However, the inspectors found that procedure QCOA 2300-04, HPCI Auto Trip, Revision 6, dated April 10, 1997, did not direct the operators to enter procedure QCOA 2300-08. The failure of the turning gear to engage upon HPCI shutdown could result in damage to the HPCI turbine, rendering it unable to perform its design function on a subsequent initiation during accident conditions. This inadequate procedure was another example of a **violation** of 10 CFR Part 50, Appendix B, Criterion V. The licensee's response to this deficiency was to revise QCOA 2300-04, HPCI Auto Trip, and reference procedure QCOA 2300-08 in the event of a failure of the HPCI turning gear to engage following an automatic trip. The inspectors verified that procedure Revision 7, dated May 29, 1997, was issued. The licensee did not, however, require operator training on procedure QCOA 2300-04, Revision 7. Following the inspectors's questions about operator training, the licensee initiated training by placing the procedure change in the required reading binder.

The inspectors were concerned that previous problems with the HPCI turning gear engagement, particularly on Unit 2 (LERs 25497008, 26595007, and PIF 96-1642), posed a real failure mode of HPCI upon restart when needed during an accident situation and that the procedure used under accident circumstances did not provide adequate instructions to cope with potential problem. Additionally, the failure to provide training to operators on this potentially safety significant issue was a weakness in the procedure revision process which did not identify the training as required.

E2.2 Facility Adherence to the UFSAR

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors reviewed plant practices, procedures and/or parameters to that described in the UFSAR and documented the findings in this inspection report. The inspectors reviewed the following sections of the UFSAR:

IR Section	UFSAR Section	Applicability
M3.1	8.3.1.6, 8.3.1.8	EDG, 4 Kilovolt Station Voltages
E2.1	7.8	Anticipated Transient Without Scram

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Licensee Event Report (50-265/95005): Automatic Scram During Electro-hydraulic Control (EHC) System Testing. The recently installed steam line resonance compensator (SLRC) circuit board time constant was set assuming a standard steam line length provided by General Electric. The steam lines were shorter at Quad Cities. The licensee recalibrated the SLRC, and the test was satisfactorily performed. The same modification was performed on Unit 2 and testing conducted in August 1996 during startup. Lessons learned from the Unit 1 transient prevented a similar event from occurring on Unit 2. This item is closed.

E8.2 (Closed) Inspector Followup Item (50-254;265/96004-07): Offgas Test Timer Drawing Discrepancy. The inspectors noted that indicating lights for the timer were not specified on the electrical schematic. The licensee confirmed that the lights were originally installed in the plant but were not on the electrical drawings. A 50.59 screening concluded that no unreviewed safety question existed. The inspectors confirmed that the drawings were updated to show the indicating lights. This item is closed.

E8.3 (Closed) Violation 50-254;265/96017-02: Residual Heat Removal Service Water Pump Bolt Incorrect Strength. In October 1996 the licensee discovered the use of inferior bolt material in the 1C and 2C RHRSW pump casings while performing maintenance on a spare RHRSW pump casing in the shop. The licensee declared the affected pumps inoperable, changed the incorrect bolt material to meet design requirements, and conducted an investigation to determine the root cause and any other related conditions. The inspectors reviewed the licensee's immediate corrective action and followup investigation and found them to be thorough and adequate. This violation is closed.

E8.4 (Closed) Violation 50-254;265/96017-04: Failure to Make Required Report in Accordance with 10 CFR 50.73. Subsequent to the licensee's discovery that the 1C and 2C RHRSW pumps were inoperable due to the use of incorrect bolt material, between July 12, 1996, and October 25, 1996, Unit 2 was operated for a period in excess of 30 days with the 2C RHRSW pump inoperable. The licensee failed to report that Unit 2 had operated beyond the TS allowed 30-day time period within the required reportability time. The licensee determined that the violation resulted from failure to follow the normal process for dispositioning PIFs. Subsequently, the licensee discussed the omission with the event screening committee (ESC) emphasizing the importance of timely processing of PIFs and improved tracking of open items. The licensee submitted LER 97-004 to document the use of improper pump casing bolts and that the 2C RHRSW pump would have performed its intended function. The inspectors reviewed the licensee's closure activities and found them to be adequate. This violation is closed.

E8.5 (Closed) Licensee Event Report 50-254/97004: Residual Heat Removal Service Water Pumps in a Degraded Condition Due to Inadequate Evaluation of Replacement Pump Casing Bolts. The licensee concluded that the affected residual heat removal service water (RHRSW) pumps were not inoperable but degraded due to the use of incorrect bolts in the low pressure pump casing. A bolt material having a lower stress limit had been installed in two of the RHRSW pumps. The higher torque value applying to the high strength material was used to install these bolts. According to the licensee's data, the maximum torque limit for the installed (lower strength) material was exceeded. However, the licensee's analysis of the removed pump casing bolts provided conclusive evidence that bolt deformation had not occurred and that the pumps would have performed their intended function in accident conditions. The licensee promptly replaced the bolts in the affected pumps upon discovery of the condition. There was also a typographical error in section B of the LER, 2nd paragraph, in which the 1C and 2C pumps were incorrectly swapped in the text. This LER is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Revised Annual Dose Goal

a. Inspection Scope

The inspectors reviewed the licensee's data for accumulated radiation dose for the Unit 2 refueling outage and discussed the revised 1997 annual dose estimate with the station ALARA coordinator.

b. Observations and Findings

The licensee revised the 1997 annual dose goal from 1260 rem to 720 rem. The inspectors reviewed the licensee's data which separated the dose into five categories - non-outage, refuel outage, contingency, emergent, and forced outage. As of June 1 all five categories showed an underage when compared to the estimate. The largest dose savings was in the area of refuel outage. Dose savings in the refuel outage were attributed to several factors including increased work efficiency and good planning in the recirculation pump motor replacement and valve work, and overall improved worker ALARA awareness. In some cases, however, the dose savings was also attributed to the fact that estimates were based on power operation of Unit 1 but the work was performed while the unit was shut down, thereby reducing the dose rates in the work area.

The inspectors noted that the revision of the dose goal was based on detailed tracking and trending and concluded that ALARA initiatives at the station were effective in reducing overall dose during the refueling outage.

c. Conclusions

As low as reasonably achievable initiatives during the Unit 2 refuel outage helped to reduce overall station dose to date. Radiation protection tracking and trending of dose was improved over previous refuel outages and allowed the mid-year revision to the dose goal. The 1997 station dose goal was revised from 1260 rem to 720 rem.

F8 Miscellaneous Fire Protection Issues (92904)

F8.1 (Closed) Licensee Event Report (50-265/93020): Continuous Fire Watch Missed for the Hydrogen Seal Oil and Turbine Seal Oil Tank Deluge System. Fire protection valves were disabled for greater than one hour and no compensatory fire watch was established. Corrective actions included training and procedure changes. The inspectors verified the actions were completed. This item is closed.

F8.2 <u>(Closed) Unresolved Item (50-254;265/96011-03) and Licensee Event Report 50-254/96013:</u> Zebra Mussel Fouling of Intake Structure. During the previous year the licensee identified zebra mussel growth in the intake structure and documented the condition on PIF 95-0915. The corrective actions for this PIF addressed cleaning and repairing the intake screens. In August 1996 the licensee identified both fire diesel pump suction strainers were fouled. Similarly, the walls of the intake structure adjacent to the "B" diesel pump suction piping were about 100 percent covered with zebra mussel growth. The licensee inspected safety-related pump suction piping and identified less than 20 percent coverage of the interior piping. Zebra mussel growth was cleaned from component piping, strainers and intake structure walls.

However, the licensee considered both fire pumps to be inoperable from May 6, 1996, when river water temperature increased to above 55 degrees F (the temperature where zebra mussels are known to spawn). Both units were shut down after May 10, 1996. The inspectors considered the licensee's corrective actions to monitor zebra mussel growth and its affects on fire pump operability to be inadequate to detect the degraded condition of the fire protection system. The inspectors consider this to be a **Violation (50-254/265-97008-05)** of 10 CFR Part 50, Appendix B, Criteria XVI, Corrective Action. This item is closed.

P8 Miscellaneous Emergency Preparedness Issues

P8.1 <u>(Closed) Licensee Event Report 50-254/96007</u>: Shut Down Of Unit 2 Due to High Winds Damaging Secondary Containment. On May 10, 1996, with Unit 2 operating at full power, high wind damaged secondary containment, the station blackout diesel generator electrical cables, and other non-safety-related structures and equipment. The licensee declared an alert and shut down Unit 2. Unit 1 was already shut down for a refuel outage. The licensee repaired secondary containment and other equipment important to operation prior to startup of the unit. The inspectors reviewed the licensee's corrective actions and consider this item closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on June 13, 1997. 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.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

E. Kraft, Site Vice President
D. Cook, Operations Manager
F. Famulari, SQV Director
J. Hutchinson, Site Engineering Manager
L. Pearce, Plant Manager
C. Peterson, Regulatory Affairs Manager
R. Svaleson, Radiation/Chemistry Superintendent
M. Wayland, Maintenance Superintendent

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 71707:	Plant Operations
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/265-97008-01	NCV	both SBGT trains inoperable during testing
50-254/265-97008-02	IFI	EDG voltage acceptance criteria not in agreement with design basis
50-254/265-97008-03	URI	TS not in agreement with procedures
50-254/265-97008-04	VIO	failure to have appropriate procedures
50-254/265-97008-05	VIO	zebra mussel fouling of intake structure

Closed

50-254/93014	LER	intermediate range monitor 11 and average power range monitor 3 both bypassed without ½ scram being inserted
50-265/93020	LER	continuous fire watch missed for the hydrogen seal oil and turbine seal oil tank deluge system
50-265/95005	LER	automatic scram during EHC system testing
50-254/96013	LER	zebra mussel fouling of intake structure
50-254/96007	LER	shut down of Unit 2 due to high winds damaging secondary containment
50-254/265-97004	LER	RHRSW pumps in a degraded condition due to inadequate evaluation of replacement pump casing bolts
50-265/97009	LER	both trains of SBGT inoperable due to fuse replacement error
50-254/97010	LER	"B" CRVS inoperable due to Freon leak
50-254/265-96004-01a	VIO	out of service errors render the ½ EDG inoperable and result in an engineered safety features system actuation
50-254/265-96004-01b	VIO	out of service errors render the ½ EDG inoperable and result in an engineered safety features system actuation
50-254/265-96017-02	VIO	RHRSW pump bolt incorrect strength
50-254/265-96017-04	VIO	failure to make required report in accordance with 10 CFR 50.73
265-94016-03	URI	reactor vessel draining evolution
50-254/265-96011-03	URI	zebra mussel fouling of intake structure
50-254/265-96004-07	IFI	offgas test timer drawing discrepancy

Discussed

None

LIST OF ACRONYMS USED

ALARA	As Low As Reasonably Achievable
ARI	Alternate Rod Insertion
ATWS	Anticipated Transient Without Scram
CFR	Code of Federal Regulations
ComEd	Commonwealth Edison Company
CRD	Control Rod Drive
CRVS	Control Room Ventilation System
DCO	Discrete Component Operations
DG	Diesel Generator
DWFDS	Drywell Floor Drain Sump
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
ENS	Emergency Notification System
ESC	Event Screening Committee
HPCI	High Pressure Coolant Injection System
IDNS	Illinois Department of Nuclear Safety
IFI	Inspector Followup Item
ILT	Initial Licensed Training
IM	Instrument Maintenance
IST	Inservice Test
kV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOR	Licensed Operator Requalification
LPRM	Local Power Range Monitor
MMD	Mechanical Maintenance Department
MOV	Motor Operated Valve
NSO	Nuclear Station Operator
PCI	Primary Containment Isolation
PDR	Public Document Room
PIF	Problem Identification Form
PMTV	Post Maintenance Test Verification
PTL	Pull-to-Lock
QCCP	Quad Cities Chemistry Procedure
QCIPM	Quad Cities Instrument Prevent Maintenance
QCIS	Quad Cities Instrument Surveillance
QCOA	Quad Cities Abnormal Operating Procedure
QCOP	Quad Cities Operating Procedure
QCOS	Quad Cities Operating Surveillance Procedure
QCTS	Quad Cities Technical Surveillance
QTS	Quad Cities Technical Surveillance
RCIC	Reactor Core Isolation Cooling
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup

SBGT	Standby Gas Treatment
SLRC	Steam Line Resonance Compensator
SRM	Source Range Monitor
STA	Shift Technical Advisor
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UPS	Uninterruptible Power Supply
URI	Unresolved Item
VIO	Violation
WR	Work Request