U. S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-254/95009(DRP); 50-265/95009(DRP)

FACILITY
Quad Cities Nuclear Power Station, Units 1 and 2

License Nos. DRP-29; DPR-30

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

DATES
October 19 through December 8, 1995

INSPECTORS
C. Miller, Senior Resident Inspector
K. Walton, Resident Inspector
J. Belanger, RIII Senior Physical Security Inspector
R. Ganser, Illinois Department of Nuclear Safety

APPROVED BY

Pat Hiland
Pat Hiland, Chief
Reactor Projects Branch 1

1/18/96
Date

AREAS INSPECTED

The inspectors conducted a routine, unannounced inspection of operations, engineering, maintenance, and plant support while routinely evaluating safety assessment and quality verification activities. Follow-up inspection was performed for non-routine events and for certain previously identified items. The inspectors performed a routine security inspection during a previous inspection period and documented the findings in this report.

Executive Summary

Operations Summary

Operators removed the Unit 2 turbine from service on October 21 due to an electro-hydraulic control (EHC) system leak. Operators shut down both units on October 22 due to the licensee's discovery that both units did not meet single failure design criteria for the scram discharge instrument volume (SDIV) logic input to the reactor protection system. The licensee corrected the condition on both units during the forced outage. Operators returned Unit 1 to service on November 13 and returned Unit 2 to service on November 23, 1995. However, on November 29, operators identified a leak in the Unit 2 EHC system identical to the October 21 leak. Operators shut down Unit 2, repaired the leak, and synchronized to the grid the same day.

Operations

- Operations demonstrated weak implementation of controls to prevent electrical bus overloads (Section 1.2.).
- Operations management response to operator errors during startup was good in one case and poor in another. Overall startup activities were well controlled (Section 1.3.).
- Operations implementation of the "Winterizing Checklist" was poor (Section 1.4.).

Maintenance and Surveillance

- Poor work practices, poor supervisory oversight, and insufficient craft skill resulted in increased unavailability of safety equipment (Section 2.1.).
- The use of classroom training and a mock-up in preparation for replacement of a Unit 2 control rod drive (CRD) was good. However, the CRD cart continued to experience malfunctions resulting in a slight increase in dose to workers (Section 2.2.).
- The licensee identified problems with incomplete main steam isolation valve closures in Unit 1. The licensee exhibited good team work to repair the valves (Section 2.3.).

Engineering and Technical Support

- Engineering root cause analysis improved. However, long term corrective actions for high pressure coolant injection (HPCI) and standby diesel generator (SBDG) were incomplete. The inspectors planned to review the licensee's assessment of these items (Sections 3.1., 3.2., and 3.3.).

- The inspectors identified low pressure steam leaks and subsequent weaknesses in the flow accelerated corrosion program (Section 3.4.).

- The licensee successfully used diagnostic equipment to determine the existence of equipment problems. Motor operated valve rotor problems were corrected prior to component failure. Diagnostic equipment for air operated valves assisted in identifying root cause failures of two HPCI valves and a recirculation sample valve (Section 3.5.).

- Inadequate reactor engineering review of control rod sequence package, generated by a new computer program, resulted in operators attempting to pull an incorrect rod. The rod worth minimizer prevented improper action (Section 3.6.).

- The root cause determination and corrective actions for an EHC system leak on October 21 were not completed prior to the leak recurring on November 29 (Section 3.7.).

- The licensee made some materiel condition improvements. Numerous items identified during walkdowns were indicative of weak system engineer and operator walkdowns (Sections 3.8. and 3.9.).

- The licensee identified that both units SDIV logic failed to meet single failure criteria as stated in the Updated Final Safety Analysis Report and Institute of Electrical and Electronics Engineers Standards. The inspectors considered this a non-cited violation due to prompt corrective actions taken by the licensee (Section 3.10.).

Plant Support

- The licensee continued to effectively manage the security program. Licensee and contract security management showed ownership of the program and demonstrated good teamwork. The licensee maintained the protected area detection system in an effective condition (Section 4.1.).

- Implementation of the new biometrics hand geometry system was good (Section 4.1.2.).

- Management administration of the security program was a strength. The inspectors noted appropriate delegation of responsibilities and staff accountability. The inspectors observed professionalism on the part of security force members in both appearance and performance of assigned duties (Section 4.1.3).

Quality

- The inspectors identified that a Licensee Event Report package, considered closed by the licensee, had not included supplemental information on subsequent valve failures and corrective actions (Section 2.4.).

- The multiple failures of the Unit 2 SBDG to start were indicative of weak root cause evaluations and corrective actions (Section 3.2.).

- Incomplete corrective action for an EHC leak which caused a turbine trip on October 21 resulted in a repeat leak and turbine trip on November 29 (Section 3.7.).

- The licensee identified poor root cause analysis and ineffective corrective actions taken on control of locked high radiation area and high radiation area events (Section 4.2.).

Summary of Open Items
Violations: not identified in this report
Unresolved Items: identified in Section 3.2.
Inspector Follow-up Items: identified in Sections 3.1. and 3.3.
Non-cited Violations: identified in Section 3.10.

INSPECTION DETAILS

1.0. **OPERATIONS:**

The inspectors used NRC Inspection Procedure 71707 to evaluate plant operations. Operations demonstrated weak implementation of controls to prevent electrical bus overloads. Operations management response to operator errors during startup was good in one case and poor in another. Overall startup activities were well controlled. Operations implementation of the "Winterizing Checklist" was poor.

1.1. Follow-up of Events (93702)

During this inspection period, the licensee experienced several events, some of which required a prompt notification of the NRC pursuant to 10 CFR 50.72. The following events were reviewed for reporting timeliness and immediate licensee response.

October 18	Emergency notification system (ENS) call. Unit 2 high pressure coolant injection (HPCI) failed to run due to oscillations with pressure, turbine speed, and flow.
October 21	Operators tripped Unit 2 turbine due to electro-hydraulic control (EHC) leak. Operators later shut down Unit 2.
October 21	ENS call. Licensee determined both units did not meet single failure criteria in scram discharge instrument volume (SDIV) input to reactor protection system (RPS).
October 22	Operators shut down Unit 1 due to RPS logic problem with SDIV.
October 23	ENS call. Rock Island County sirens inoperable.
October 24	Unit 2 standby diesel generator (SBDG) failed to start during surveillance test.
October 25	Leak in Unit 2 drywell due to reactor building closed-cooling water line to "G" drywell cooler leaking.
November 4	Shared SBDG failed to run due to relay failure.
November 9	Operators take Unit 1 critical, but shut down the following day due to packing leak on a steam drain valve.
November 13	Operators started up and synchronized Unit 1 to the grid.
November 20	Unit 2 SBDG failed surveillance test and declared inoperable.
November 23	Operators started up and synchronized Unit 2 to the grid.
November 29	An EHC leak forced operators to shut down Unit 2. The licensee repaired the leak. Operators started up and synchronized Unit 2 to the grid.
November 30	ENS call, operators declared Unit 2 HPCI inoperable.
December 5	ENS call, loss of ENS phones.
December 6	ENS call, operators declared Unit 1 HPCI inoperable due to stop valve stroke time.

1.2. Administrative Controls Not Implemented

The inspectors identified that administrative controls required to prevent safety bus feeder cables from becoming overloaded were not in place prior to installing a modification on a 480 volt motor control center. The inspectors were concerned that operations management was not aware of the status of administrative controls on safety related equipment.

On October 31 the inspectors questioned the licensee on the status of implementing interim administrative controls to prevent safety bus feeder cables from becoming overloaded. According to licensee's engineering documents, these controls were to be implemented prior to increasing the trip settings of the bus feeder breakers. The licensee had changed one-half (7 of 14) of the bus feeder trip settings without administrative controls in place. Operations management believed controls were in place, but discovered the administrative controls had not been implemented. Based on the inspectors' questions, the licensee subsequently implemented the controls directed by the engineering documents late on October 31. The inspectors verified the controls were in place.

1.3. Unit 2 Startup Activities

On November 22 the inspectors observed reactor startup activities on Unit 2. The inspectors noted that the Operating Unit Supervisor maintained effective control of startup activities. The inspectors observed one manipulative error made by the nuclear station operator that resulted in a half-scram signal. The operator made a self check error. The operator acknowledged the error of ranging down an intermediate range monitor instead of up-ranging. The unit supervisor coached the operator. During the startup, operators caused a generator trip due to improper entry into an operating procedure. Operators incorrectly marked required steps in the operating procedure as not applicable. Operation's management followup of the first error was prompt, however, the followup from the second event was not prompt and the corrective actions were not clear.

1.4. Winterizing Checklist

The inspectors reviewed the licensee's equipment winterization program included in QCOP 010-1, "Winterizing Checklist," and found several weaknesses. The due date for winterizing activities to complete was November 3, 1995. Inspectors reviewed progress of the checklist on November 5, and found many items incomplete. The inspectors conducted a followup review of the checklist on November 28. The inspectors identified the licensee had made little progress in completing the checklist. In addition, the licensee had not addressed actions for equipment out of service identified by the checklist. The licensee had not verified electrical operation of most items. The inspectors considered followup of this scheduled item to be poor.

2.0. MAINTENANCE:

The inspectors used NRC Inspection Procedures 62703 and 61726 to evaluate maintenance and testing activities. On October 23 the licensee shut down all but essential maintenance activities. During the maintenance stand down, the licensee reevaluated the work control process. The licensee continued to have problems meeting the daily maintenance schedule and problems with worker skills. Late in the period, poor maintenance practices resulted in damaging "1C" Residual Heat Removal Service Water (RHRSW) pump components. This resulted in extending time spent in a limiting condition for operation.

2.1. Poor RHRSW Pump Maintenance

The inspectors observed maintenance activities on "1C" RHRSW pump and noted several significant weaknesses and one significant strength.

The licensee intended to inspect the casing and replace bearings and seals of the "1C" RHRSW pump. However, workers identified improper impeller clearance and decided to replace the shaft. The maintenance craft failed to return the work package to work analysts for revision when the work scope grew. Tolerances for the shaft and instructions for replacing the shaft were not included in the work package. When fitting the old impeller onto the new shaft, workers damaged the brass impeller with a soft coated hammer. Workers removed the damaged impeller and prepared a new impeller for installation. While attempting to increase the inner diameter of the new impeller to fit onto the shaft, workers improperly milled the impeller. Maintenance personnel were forced to use a third impeller and shaft staged for the "2D" RHRSW pump. At that point, licensee management stopped work activities to replan the job.

The inspectors were concerned that poor work practices resulted in increased unavailability of safety equipment and indicated poor supervisory oversight, craft skill, and work package coordination. The inspectors considered management intervention into the maintenance activity appropriate.

2.2. Control Rod Drive (CRD) Work

The inspectors noted the licensee made good preparations for replacement of a CRD mechanism. However, the CRD cart elevator malfunctioned resulting in workers receiving extra dose.

During the Unit 2 forced outage, the licensee planned to remove and replace defective CRD K-7. In preparation for this high radiation dose job, the licensee performed both classroom and mock up training on the use of the CRD cart and CRD installation and removal procedures. However, during the actual CRD reinstallation, the cart's elevator air motor malfunctioned. (See inspection reports (IR) 50-254/265-95005 and

95006 for information on previous CRD cart failures.) Workers took extra time in a high radiation area to assist the elevator in raising the CRD into the proper position. The licensee received a new CRD cart which will replace the existing defective cart.

2.3. Main Steam Isolation Valve (MSIV) Failure to Close

On November 3 the licensee tested Unit 1 MSIVs to ensure the valves would close on spring pressure alone. The licensee identified that "1C" and "1D" MSIVs failed to fully close during the "fail safe" test. The licensee believed the stem was binding due to packing deterioration. After stroking the valves without packing, the licensee replaced the packing for both the affected valves. The licensee retested the valves successfully. The licensee's corrective action included continued performance monitoring of the valves, and evaluation of whether to change the MSIV actuators and springs during the upcoming refuel outage. The inspectors identified good communications and team work between departments, good management involvement, and well planned execution of the repair effort.

2.4 Follow-up on Non-Routine Events and Previously Opened Items. The inspectors used NRC Inspection Procedures 92701 and 92702 to review previously identified items and to ensure that corrective actions were accomplished in accordance with the technical specifications. This included reviewing the responses to notices of violation, inspection follow up items (IFIs), and licensee event reports (LERs).

(Open) Inspector Followup Item 50-254/265-94010-03: Solenoid Air Operated Valve (AOV) Problems. The licensee identified that Unit 2 primary containment isolation AOVs 2-220-44 and 45 had not closed from the control room. The licensee considered the AOVs inoperable and attributed the AOVs failure to excessive stem/packing friction. As corrective actions, the licensee disassembled and reassembled the valves and then placed the AOVs on an increased testing frequency. Believing the AOVs were repaired, the licensee closed this item in mid-September 1995. However, the 2-220-44 valve failed to close again on October 16. The licensee declared the valves inoperable and utilized AOV diagnostic equipment to determine that the 2-220-44 valve seat loading and valve stroke needed adjustment. After the licensee made the adjustments, the valve failed the local leak rate test. The licensee attributed the failure to the valve disc not being properly centered on the seat. The licensee repaired the valve again and declared the valve operable after successfully testing.

The inspectors consider this item open since the documentation in the closure package was incomplete. The inspectors identified that the regulatory assurance documentation had not included additional work performed and a revised root cause analysis. Additionally, the inspectors needed to review the licensees planned use of AOV diagnostic equipment to allow better assessments of AOV performance. This item remains open.

(Open) LER 265/94008 and Rev 1: "Inboard and Outboard Reactor Recirculation Sample Isolation Valve 2-220-44 and 45 Failure to Close During Surveillance." This item was identical to IFI 50-254/265-94010-3 addressed above. This LER is considered open since the supplemental information submitted to the NRC had not included subsequent valve failures and corrective actions. This LER remains open.

(Closed) LER 265/94012: "Unit 1 Drywell Pressure Switches Found Outside Technical Specification Limits." With Unit 1 shut down, the licensee identified five of eight pressure switch setpoints drifted out of TS calibration limits. The licensee recalibrated the switches and increased the frequency of switch calibration. The licensee replaced the 1001-83, 88, 89, and 90 series of pressure switches in both units. The inspectors noted that the new drywell pressure switches calibration checks have been satisfactory. This LER is closed.

(Closed) LER 254/94016: "Support Rod for Suction Side Piping Common to RHRSW was not Tightened Correctly." During maintenance on the shared SBDG cooling water pump, the licensee identified a loose pipe support. The licensee changed maintenance procedure QCMM 1530-9, "Post Maintenance Verification Guide for Pumps," and trained mechanical maintenance workers to check for possible movement of hangers or supports during pump maintenance. The licensee corrected the loose hanger and changed the piping support to the shared SBDG cooling water pump. The inspectors reviewed the procedure change and closely followed the shared SBDG cooling water pump work. This LER is closed.

3.0. ENGINEERING AND TECHNICAL SUPPORT:

The inspectors used NRC Inspection Procedure 37551 to evaluate engineering. Engineering staff investigated numerous safety and non-safety related equipment failures during the period. The licensee's root cause investigation techniques were improving, but failed to prevent repeat EHC system leaks and SBDG failures. The inspectors noted increased use of diagnostic equipment to assist in determining equipment performance problems. The licensee expanded an existing diagnostic program to detect pipe thinning. However, the program was not implemented for certain piping to the condenser. This piping exhibited numerous leaks requiring workers enter into high radiation areas to effect repairs.

3.1. Failure of Shared SBDG to Run

On November 4 the shared SBDG failed to start due to an apparent failure of a TD-1 time delay relay. The inspectors continued to be concerned with the dependability of the SBDGs and weaknesses in the licensee's root cause investigations.

On November 4 operators started the shared SBDG for a monthly surveillance test. The SBDG and support equipment started properly. However, about 15 seconds after starting, the shared SBDG stopped. Operators received a "Main Bearing Oil Pressure Low" annunciator. On November 5 operators started the shared SBDG with monitoring equipment installed. The SBDG started properly then stopped after about 11 seconds. Data collected by the licensee indicated that the TD-1 relay had failed.

The TD-1 relay allowed the SBDG to start with the low oil pressure trip bypassed for the first 90 seconds; allowing the oil pressure to buildup without tripping the SBDG on low lube oil pressure. Monitoring equipment indicated that the TD-1 relay timed out after only 10.5 seconds. Maintenance technicians replaced the relay and the surveillance test was completed satisfactorily. Operations declared the SBDG operable on November 6.

Maintenance recently replaced both TD-1 relays on the Unit 1 and Unit 2 SBDGs. The licensee calibrated the TD relays each refueling outage. The licensee sent the failed TD-1 relay out for analysis. Results were expected in mid-December 1995. Preliminary results gave little information about the reason the TD-1 time delay had changed. The inspectors consider this an **Inspector Follow-up Item (50-254/265-95009-01)** pending review of the licensee's root cause analysis.

3.2. Failure of Unit 2 Standby Diesel Generator to Operate

The licensee continued to exhibit weak root cause investigation for the Unit 2 SBDG failures. This resulted in the Unit 2 SBDG failure to start during three consecutive monthly surveillance tests.

On August 28, two operators suspected slower than normal starting time of the Unit 2 SBDG during performance of operations surveillance procedure QCOS 6600-01, "Monthly SBDG Load Test." The licensee documented this condition on Problem Identification Form (PIF) 95-2302. The licensee started the SBDG on August 30. The SBDG start and load times corresponded to approximately the same times as those documented during a test performed on July 5. These times were satisfactory and met technical specification (TS) requirements. The licensee's investigation had not identified a root cause for the slower than normal start time. The system engineer initially documented on the PIF that either the governor booster pump or the air start motors may not be operating correctly. After the August 30 test, engineers indicated there was significant evidence to determine that a problem did not exist. The licensee closed the PIF stating the root cause as "none."

On September 26, the Unit 2 SBDG failed to start during performance of the monthly surveillance. The licensee conducted an investigation (PIF 95-2472) and attributed the cause of the failure as intermittent operation of the fuel oil priming pump. The root cause investigation was weak in that a broad spectrum of causes for the poor performance in August and September were not considered. The licensee replaced the fuel oil priming system pump and motor then conducted repeated tests of the fuel oil system. The licensee performed several successful starts of the Unit 2 SBDG then declared the machine operable on September 29. Later, the licensee received test results indicating that neither the fuel priming pump nor the motor, which had been removed earlier, were degraded. Engineers failed to act on this information to reopen the root cause investigation.

On October 24 during a Unit 2 SBDG surveillance test, the diesel again failed to start (PIF 95-2701). The licensee conducted another test approximately 1 hour later and the diesel started successfully. The licensee assembled a team with assistance from corporate engineering and vendor representatives, and subsequently initiated a more extensive effort to determine the root cause of the failure. From this team effort, the licensee concluded the cause of failure was a faulty air start motor. The licensee attributed the cause of both start failures, on September 26 and October 24, and also the slow start on August 28 to the faulty air start motor. The root cause investigation was more thorough, but did not provide conclusive evidence of air start motor degradation.

On November 2 the inspectors attended the licensee's Plant Operations Review Committee (PORC) meeting to observe the discussion of the trouble shooting team's efforts and conclusions for the October 24 failure to start. The PORC members concluded that the Unit 2 SBDG was operable upon successful completion of operability testing. The inspectors observed that the PORC members had not thoroughly reviewed the depth of the root cause determination when assessing SBDG dependability.

On November 19 and 20 the licensee perceived the Unit 2 SBDG to start slowly. The licensee documented this condition (PIF 95-2881). The licensee placed monitoring equipment on the diesel control circuit and identified sluggishness in the governor controls. The licensee changed out a time delay relay and a governor shutdown solenoid and successfully completed an operability test on November 21. The licensee believed these conditions may have contributed to the failure to start events on September 26 and October 24.

The inspectors noted several other problems indicative of weak maintenance, engineering, and corrective action practices:

- The licensee identified that the upper air start motor was not properly lubricated prior to installation. Maintenance procedure QCMMS 6600-03, "Emergency Diesel Generator Periodic Preventive Maintenance Inspection," had not contained instructions for pre-lubricating newly installed air start motors as recommended by the vendor manual.

- An earlier 10 CFR Part 21 notification to the licensee identified the air start motor rotor vanes as being susceptible to moisture degradation. The licensee identified that onsite storage of the air start motors was not in a manner which would prevent moisture intrusion of the air start motors. The inspectors identified nearly a month later that the storage problem had not been addressed, the root cause not determined, and the scope of the problem (including rebuilt motors) had not been properly considered.

- The system engineer recommended increased frequency of testing to weekly to enhance confidence in dependability. However, the licensee had not scheduled Unit 2 SBDG for increased testing frequency by December 15, nearly a month after the previous failure. Work scheduling problems and hesitancy of operators to test the SBDG were cited as reasons why the engineers were not successful in increased frequency testing.

- The Level 2 investigation of the SBDG failures had not received significant corporate management oversight or support.

The inspectors considered the management oversight and corrective action followup of the series of SBDG problems as weak. The licensee failed to take prompt and effective corrective actions to ensure SBDG dependability. The inspectors consider this an **Unresolved Item (50-254/265-95009-02)** pending review of the licensees corrective actions.

3.3. Unit 2 HPCI Failed to Run

The licensee's initial approach to determine the root cause of the Unit 2 HPCI failure was an improvement over previous investigations. However, at the end of the period, the licensee had not determined the root cause of Unit 2 HPCI turbine oscillations. Additionally, the licensee used diagnostic equipment to evaluate performance of air operated valves (AOVs). This effort identified deficient operating conditions for several AOVs.

On October 18, operators identified pump discharge pressure and flow and turbine speed oscillations on Unit 2 HPCI. During trouble shooting, operators tripped Unit 2 HPCI due to an annunciator indicating that the inlet main steam pot had not drained. Operators attempted to open the main steam supply trap to drain pot isolation valve, AOV 2-2301-28, but the valve failed to open. Engineering, maintenance, and operations established a team to determine likely causes of the Unit 2 HPCI failure.

The licensee believed the steam pot had not drained due to minor corrosion on the steam pot drain level switch which caused the switch to stick. The licensee removed the corrosion. The licensee attributed the corrosion to a steam leak which was corrected earlier. The inspectors observed testing of the drain pot level switch and noted the level switch performed its intended function.

The team utilized AOV diagnostic equipment to measure performance of AOV 2-2301-28. The licensee determined the supply air pressure to the AOV was too high. This resulted in excessive valve seating force and necessitated replacing damaged internals. The licensee identified and corrected similar concerns identified with the Unit 1 AOV 1-2301-28.

The licensee operated HPCI during the Unit 2 startup on November 23. The licensee observed minor HPCI oscillations at rated pressure and made slight adjustments to the flow controller. The licensee declared the system operable without identifying the root cause of the failure but increased the frequency of testing. During operation of Unit 2 HPCI on November 30, operators observed oscillations and declared HPCI inoperable. The licensee believed the turbine oscillations were generated by a synchronized mechanical linkage response to flow control signals. The licensee tested HPCI after performing adjustments to flow controller parameters. Operators declared Unit 2 HPCI operable on December 6. The inspectors consider this an **Inspector Follow-up Item (50-254/265-95009-03)** pending review of the licensees' root cause analysis.

3.4. Steam Leaks

The inspectors and licensee identified several steam leaks on the Unit 1 "below seat drain" piping from the turbine control valves and on the "1C1" and "1C2" feedwater heater vent piping. The licensee temporarily repaired the leaks with clamps and/or furmanite. The repairs required entry into high radiation areas.

In both cases, the piping was 2 inches or less in diameter and had been identified by the licensee's Flow Accelerated Corrosion (FAC) program as susceptible to corrosion. Piping of that size that was susceptible to corrosion was called susceptible not modelled (SNM). However, the SNM piping was not in the original FAC program scope of larger diameter piping. The inspector identified that no SNM piping had been included in the scope for inspection during the upcoming Q1R14 outage. The licensee planned to review the outage scope based on the corrosion identified.

3.5. Use of Diagnostic Equipment to Detect Equipment Problems

The inspectors noted good licensee followup to degraded valve performance related to magnesium rotors on motor operated valves (MOV) in the recirculation and residual heat removal (RHR) systems. The inspectors noted the licensee implemented a program to detect performance problems with magnesium rotors using Motor Power Monitoring (MPM). The MPM was a valuable tool in early detection of MOV rotor cracking on the Unit 1 recirculation loop B pump discharge valve, and several other valves in high temperature primary containment environment. The licensee was tracking corrective actions for this problem under PIF 95-2716.

Similarly, the licensee utilized diagnostic equipment to determine problems with air operated valves (AOVs). The licensee borrowed the equipment from the LaSalle Nuclear Station and diagnosed problems with both units' HPCI valve, AOV 2301-28. (See Section 3.3 above for additional information.) The equipment identified air pressure to the valve was set too high and identified other problems. The licensee disassembled the valves and found damaged internals. The licensee replaced both valves internals and adjusted the supply air pressure. Similarly, the equipment detected longstanding problems with a Unit 2 recirculation system sample valve. The licensee repaired the valve.

The licensee planned to acquire a similar AOV diagnostic tool and train engineers to operate the equipment. The inspectors noted increased use of diagnostic tools in the facility in an attempt to identify equipment problems prior to equipment failure.

3.6. Computer Program Error Identified During Rod Withdrawals

A first time use of a computer program, coupled with an inadequate review of the rod sequence package produced by the program, resulted in the rod worth minimizer (RWM) prevented the movement of an incorrect control rod.

On November 14, the RWM prevented operators from moving the next control rod in the sequence provided by reactor engineering. The operations manager suspended all rod moves until reactor engineering reviewed the event. Reactor engineering determined that the wrong rod array had been referenced when the control rod sequence package was generated. Reactor engineering inadequately reviewed the rod sequence package produced by the computer program. The new program was designed to replace the previous manual method of selecting, editing, and printing rod sequence sheets. Since reactor engineering loaded the correct rod arrays into the RWM, the RWM prevented an out of sequence rod withdraw.

The licensee verified the rod pattern to be correct and corrected the computer program error. Reactor engineering received training on this event including the responsibilities of reviewers.

3.7. Turbine Trip Due to Failed Turbine Control Valve (TCV) Piping

The root cause determination and corrective actions for an electro-hydraulic control (EHC) system leak on October 21 were not completed prior to the leak recurring on November 29.

On November 29, operators tripped the Unit 2 main turbine after receiving a low EHC pressure alarm. The licensee identified failed tubing between a pressure transmitter and the EHC control manifold for the #1 TCV. This was an exact repeat of a failure of the same tubing on October 21 which resulted in a turbine trip. As a corrective action from the October 21 event, the licensee closed an isolation valve on the manifold to isolate the tubing. The licensee documented the October 21 event on PIF 95-2690 which was due for closure on November 23. The PIF was not closed, nor overall root cause addressed prior to the November 29 event. After the November 29 event, the licensee found the valve opened slightly and the tubing cracked. Corrective actions after the second event included removal of the unnecessary transmitter. The licensee replaced the affected tubing with a plug.

3.8. <u>Materiel Condition Walkdown Discrepancies</u>

The inspectors identified several discrepancies during plant and system walkdowns which indicated poor materiel conditions were allowed to linger.

- After a heavy rain, inspectors identified water leaking onto a 13.8 kv transformer and on top of the Unit 1 SBDG output junction box in the turbine building. The leaks were similar to other leaks found in the turbine building previously. The licensee corrected the immediate issue when informed, but not the overall problem.

- The inspectors identified fluid leakage onto junction boxes containing reactor protective system terminal boards. Further investigation by the licensee indicated the fluid had entered the boxes. The licensee had not identified the source of the leakage which had caused significant contamination on the Unit 1 reactor building walls.

- The inspectors identified a steam leak in the Unit 1 heater bay on a turbine control valve below seat drain. Maintenance workers later repaired the leaks with mechanical clamps and furmanite. (See Section 3.4 above for additional information.)

- Inspectors identified numerous examples of scram valve limit switches not properly aligned. Many of these had been identified previously and not corrected; some were recently identified. The limit switches provided scram valve position indication to control room operators and had no affect of the operability of the scram valves.

- Inspectors identified boron deposits indicative of small leaks on Unit 2 standby liquid control (SBLC) relief valves and heat trace elements for Unit 2 SBLC not set at the appropriate temperatures.

- During a drywell inspection, inspectors identified water leaking by a closed valve in the reactor building closed cooling water (RBCCW) system to the "2G" drywell cooler. The leaking valve allowed water containing nitrites to leak into the drywell basement and into the torus. The licensee had closed and tagged the valve to support repair efforts on the "2G" drywell cooler. The licensee eventually changed the tag boundary to stop the leak; but not before the RBCCW leak caused nitrite levels in the torus water to exceed allowable limits. This required a significant cleanup effort by operators and chemists and included the purification of hundreds of thousands of gallons of torus water.

Based on the numbers and types of discrepancies described above, the inspectors determined that some system engineer and operator walkdowns and followup of materiel condition issues were not thorough.

3.9. Materiel Condition

The following were examples of equipment problems identified by the licensee

- EHC leaks at the same fitting resulted in operators tripping the Unit 2 turbine twice.
- "2G" drywell cooler fan threw a blade, which resulted in a leak of RBCCW system.
- "1E" drywell cooler power supply cable experienced a high current condition. The licensee replaced the overloaded cable.
- Operators removed "2A" control rod drive pump from operation after identifying degraded performance.
- Continued spiking of the Unit 1 service water radiation monitor.
- "2B" reactor building exhaust vent fan tripped without reason.
- Unit 2 SBDG vent fan tripped due to undersized thermal overloads. The licensee replaced the overloads with overloads of a higher rating.
- The licensee placed the 1/2 instrument air compressor on limited service status due to increased vibration and temperature indications.
- Clogged drain on Unit 1 offgas moisture separator resulted in moisture carryover into the absorber beds.

The licensee corrected the following material condition issues:

- Operators placed Unit 2 feedwater flow control into three element control. This resulted in less wear on the feedwater regulating valve and improved system response.
- Engineering corrected Unit 2 turbine control valve oscillations.
- Operators returned Unit 2 air operated valve 220-44, a primary containment isolation valve, to service after root cause of failure was identified.

3.10 Follow-up on Non-Routine Events and Previously Opened Items. The inspectors used NRC Inspection Procedures 92701 and 92702 to review previously identified items and to ensure that corrective actions were accomplished in accordance with the technical specifications. This included reviewing the responses to notices of violation, IFIs, and LERs.

(Closed) Inspector Followup Item 50-254/265-94004-38(DRS): Pressure locking and thermal binding (PL/TB) screening criteria had not been implemented. This item can be closed based on issuance of Generic Letter (GL) 95-07, "PL/TB of Safety-Related Power-Operated Gate Valves." Quad Cities' screening criteria and acceptability of all valves deemed susceptible to PL/TB will be evaluated under the inspection guidance of the GL. This item is closed.

(Closed) LER 254/265-95007: "Control Rod Drive Scram Discharge Volume Control Logic Fails to Meet Single Failure Criteria due to Design Deficiency." The licensee identified the deficient condition and shut down both units in compliance with TS. The licensee performed modifications to both units scram discharge instrument volumes (SDIVs) to ensure compliance with single failure criteria. The licensee considered the modification performed on Unit 1 as temporary and planned to perform a permanent modification during the upcoming refueling outage. The inspectors reviewed both units modification packages and observed modification installations. The licensee's corrective actions were adequate to prevent recurrence.

The failure to install SDIV logic circuitry without meeting single failure criteria in accordance with Updated Final Safety Analysis Report (UFSAR) and Institute of Electrical and Electronics Engineers (IEEE) Standard 279 (1968), was considered a violation of 10 CFR Part 50, Appendix B, Criteria III, "Design Control." This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This LER is closed.

4.0. PLANT SUPPORT:

The areas of the security program that were reviewed were effectively managed, were well maintained, and had a good self assessment program. The licensee exceeded the 1995 stretch goal for station dose in November and set a new goal for 1995 of 735 person rem. At the end of the report period, station dose was about 720 person rem. The licensee identified a hot particle on a person leaving the facility. The licensees' investigation was thorough but had not identified the origin of the particle. A radiation worker error caused a minor face contamination due to improper implementation of the radiation work procedure. The inspectors identified a hot spot in accessible areas of the Unit 2 reactor building which was not properly marked in accordance with procedures. The licensee corrected the problem and was reviewing why the area had not been properly marked. A radiological task force identified weaknesses and recommended improvements in control of high radiation areas. The recommendations were accepted by management.

4.1. Security Program Review

The inspector used NRC Inspection Procedure 81700 to evaluate physical security during the week of October 16-20, 1995. Self assessment in the area of security was accomplished through the efforts of the Site Quality Verification Program, the off-site security contractor audits, and the efforts of the quality assurance auditor of the onsite contract security organization. The inspectors concluded the licensee's self assessment program was good.

A review of security incident reports and security loggable events showed few personnel errors attributed to security personnel. The majority of the security loggable events were attributed to environmental factors affecting the perimeter alarm system. The inspector determined that maintenance support was adequate in addressing identified problems and that the total number of sector failures did not appear to be excessive.

Security force performance was good despite increased job stress caused by reductions of some armed security personnel to watchmen status, more stringent performance standards for armed response team members, and the general prospect of future personnel reductions. This had negatively affected employee attitudes but had not translated into performance concerns.

4.1.1. Effectiveness of Perimeter Detection System

The inspector observed a quarterly performance test of the perimeter alarm system. Testing was aggressive and comprehensive and all zones tested performed well.

The licensee's tracking of security loggable events for the month of September 1995 showed that the 35 security equipment events represented 92.1 percent of the 38 security events for the month and that 29 of the 35 events related to perimeter zone problems.

4.1.2. Implementation of Hand Geometry Protected Area Access Control System

On August 16, 1995, the licensee implemented a biometrics hand geometry access control system at the entrance to the protected area. By letter dated July 26, 1995, the NRC granted the licensee an exemption to the 10 CFR 73.55 badging requirements relating to the issuance, storage and retrieval of picture badges for individuals who have been granted unescorted access to the protected area. Specifically, the exemption allowed individuals to keep their picture badge in their possession when departing the site. The inspectors observed that the new system functioned well and employees were experienced in using it.

4.1.3 Management Administration of the Security Program: Program Strength

Licensee and contract security management provided excellent administration of the security program. A high level of experience and professional dedication characterized the management staff. Responsibilities and accountability were clearly defined and understood by both management and subordinates. Management was aware of current issues and problems and were kept well informed by their subordinates.

4.2. Licensee Evaluation of Control of High Radiation Barriers

The inspectors reviewed the task force report for review of locked high radiation (LHRA) and high radiation area (HRA) control problems. The report identified weaknesses in root cause analysis of HRA events and weaknesses in personnel accountability. The inspectors considered the task force findings and the licensee's commitment to implement changes recommended by the report, as good.

Since January 1994 the licensee identified about 20 documented problems with control of LHRA and HRA. The licensee assembled a task force to investigate common causes, recommend possible solutions, and develop an implementation plan for corrective actions. Although the report stated that the PIF program identified problems well, almost 75 percent of previous PIF evaluations had not adequately identified root causes of LHRA and/or HRA deficiencies. The task force determined that almost 80 percent of deficiencies were due to personnel performance. The task force recommended that management set definitive expectations and hold personnel accountable for radiological controls violations. Additionally, the task force recommended radiological first line supervision demand quality reviews for all radiological incidents.

The task force made these and other recommendations to management and proposed implementation dates for corrective actions. These plans were incorporated into the licensees nuclear tracking system with individuals and dates assigned to each item.

4.3. Follow-up on Non-Routine Events and Previously Opened Items. The inspectors used NRC Inspection Procedures 92701 and 92702 to review previously identified items and to ensure that corrective actions were accomplished in accordance with the technical specifications. This included reviewing the responses to notices of violation, IFIs, and LERs.

(Closed) Violation 50-254/265-94026-05: Fifty one security implementing procedures that addressed protected information were not marked "Safeguards Information" in a conspicuous manner. These procedures were "draft" procedures and were essentially the same as final procedures which were marked as safeguards information. The licensee was not required to reply to this violation since steps had been taken to correct the violation and to prevent recurrence. The licensees corrective actions included the stamping of each page and the establishment of a self assessment program by December 1994.

The inspector verified through interviews with the Station Security Administrator (SSA) that the self assessment program in the area of safeguards information was established. An audit performed by the SSA in the summer of 1995 identified minor inconsistencies in the marking of safeguards documents which were resolved. This item is closed.

(Closed) Program Observation: Lack of security officer participation in tactical "force-on-force" drills in the last 14 to 24 months, (documented in IR 50-254/265-95004). Five armed officers, hired in the last year, had never participated in the program. The lack of drill participation could have reduced the effectiveness of individual response to emergency security situations.

Interviews with the contract training staff showed all but 11 of the armed officers had participated in at least one "force-on-force" drill in 1995. The training supervisor stated all but 1 of the 11 will complete the drill by October 25, 1995. The remaining individual will complete the drill by November 21, 1995. The training supervisor noted that individuals on assigned drill dates could be involved in three to five drills per shift. This item program observation is closed.

(Closed) Violation 50-254/265-95004-05: Failure to perform initial physical examinations for nine members of the security force. As part of the licensee's immediate corrective action, all nine watch persons were relieved of their duties until they received a physical exam. All nine successfully passed the physical exam by May 25, 1995, and returned to work.

The licensee determined that the violation was the result of an error in judgment. This group of watch persons was the first hired since the implementation of the watch person program. An annual physical exam of the watch persons was not required, unlike the armed security officers. This lack of an annual physical exam requirement was interpreted by the security contractor as not requiring physical exams for watch persons.

The licensee's station security administrators and security contractor managers were made aware of the error. The violation was discussed at the Station Security Administrator's meeting held on May 25, 1995. The actions taken to avoid further violations were considered appropriate. This item is closed.

5.0. Exit Interview

The inspectors met with the licensee representatives denoted below during the inspection period and at the conclusion of the inspection on December 8, 1995. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

The following management representatives attended the exit meeting conducted on December 8, 1995, along with others.

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Bill Pearce, Station Manager
Dave Cook, Operations Manager
John Hutchinson, Site Engineering Manager
Curt Smith, Maintenance

6.0. DEFINITIONS

6.1. Non-cited Violations

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, for a violation of minor safety significance or a licensee identified Severity Level IV violation that meets the criteria described in the NRC Enforcement Manual, the NRC will not generally issue a Notice of Violation. Violations of regulatory requirements identified during this inspection for which a Non-cited Violation was issued is discussed in Section 3.10.

6.2. Unresolved Items

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items violations or deviations. An Unresolved Item disclosed during this inspection is discussed in Section 3.2.

6.3. Inspection Followup Items

Inspection Followup Items are matters which have been discussed with the licensee which will be reviewed further by the inspectors and which involve some action on the part of the NRC or licensee or both. Inspection Followup Items disclosed during this inspection are discussed in Sections 3.1. and 3.3.