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:	January 28 - March 17, 1997
Inspectors:	C. Miller, Senior Resident Inspector K. Walton, Resident Inspector L. Collins, 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 50-254/97002(DRP), 50-265/97002(DRP)

This inspection included aspects of licensee operations, surveillance, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection.

Operations

The decision to declare the automatic depressurization system (ADS) valves inoperable due to seat leakage was appropriate. Unit 2 shutdown activities were in accordance with licensee procedures and were well executed (Section O1.2).

Control measures taken by operations to improve the working environment in the control room were effective. The licensee's effort to provide more stringent control of room access, incoming phone calls, and general noise level was evident (Section O1.3).

Initial operator response to the failure of the reactor protection system (RPS) relay was appropriate. Subsequent reset of the B trip system was contrary to procedures and was not in compliance with the Technical Specification (TS). The decision to shut down Unit 1 to perform a root cause analysis of the failure was appropriate and reflected conservative decision making. (Section O1.4).

The inspectors reviewed open operability assessments and found all items to be adequately tracked by the licensee. However, the inspectors identified one degraded equipment operability issue that was not on the licensee's list of open operability issues (Section O1.5).

The operator failure to properly maintain turbine building negative pressure in accordance with the annunciator response procedures could have resulted in the spread of contamination within and outside the turbine building. This failure was a procedural violation. Other operational problems noted during the inspection included a weak response to a degraded drywell equipment drain sump isolation valve and additional ventilation problems related to control of a modification (Section O2.1).

Maintenance

The inspectors noted problems identified by workers in the field resulted in additional time spent in TS limiting condition for operations (LCO), some additional radiation exposure to workers, or affected equipment used to support reactor operations. Some of these events were the result of poor quality work packages (Section M1.1).

Both the inspectors and the licensee identified instrumentation used by operators to determine equipment operability and for equipment trending that were not included in a calibration program (Section M2.1).

The inspectors had concerns with the licensee's implementation of the maintenance rule, specifically the identification of maintenance preventable functional failure (MPFF) events and the failure to promptly evaluate the Unit 2 containment atmosphere monitoring (CAM) system status as (a)(1) under the maintenance rule. Longstanding issues regarding repetitive regulator failures and water intrusion in the CAM system had not been resolved (Section M2.2).

Surveillance

During a Unit 2 surveillance on the high pressure coolant injection (HPCI) system, operators quickly assessed that injection was not required and secured HPCI after an unexpected auto-initiation. However, operators had an opportunity to identify that scheduled activities were incompatible with existing plant conditions (Section O4.1).

Engineering

The inspectors identified a vulnerability in the licensee's method of identifying and reporting of 10 CFR Part 21 issues. However, the inspectors did not identify any instances where 10 CFR Part 21 notifications were not made when required (Section E7.1).

Plant Support

The inspectors identified that some radiation protection technicians (RPTs) lacked good command and control of radiological aspects of the assigned work. This resulted in some increase in dose to workers and the potential to spread contamination into clean areas (Section R1.1).

The inspectors concluded that the high radiation sampling system (HRSS) drill was successful and that personnel performance was good (Section R4.1).

Report Details

Summary of Plant Status

Unit 1 operated at or near full power throughout most of the inspection period. Between February 14 and February 19 Unit 1 power was reduced for troubleshooting the 1B feedwater regulating valve. Power was again reduced on February 25 to swap the reactor protection system power bus to the preferred source. On March 11 the unit was shut down to repair a failed reactor protection system relay. Restart of Unit 1 began on March 16, and the generator was on-line March 17.

Unit 2 operated at or near full power throughout the inspection period. Power was reduced on February 25 for testing of the feedwater flow system instrumentation. On February 28 the unit was shut down one-half day earlier than scheduled for refuel outage Q2R14 due to TS requirements related to surveillance testing of automatic depressurization system valves. Unit 2 remained shut down for a planned 60-day refuel outage, Q2R14. Major activities planned during Q2R14 included inspection of the reactor vessel beltline welds and bottom head drain clean out, main turbine disassembly and inspection, overhaul 2A core spray pump, 2B residual heat removal (RHR) heat exchanger inspection and repair, scram solenoid pilot valve diaphragm replacement, replacement of emergency core cooling system (ECCS) suction strainers; safety-related breaker and cable replacement, and Generic Letter 96-06 piping relief valve modifications. The Unit 2 startup was scheduled for the end of April.

I. Operations

O1 Conduct of Operations*

O1.1 General Comments (71707)

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

February 21 A notification was made that the Train B control room ventilation refrigerant compressor unit was inoperable due to high temperatures in the old computer room.

February 27 A notification was made that the Unit 2 HPCI automatically actuated during a surveillance test.

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*Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

February 28 A notification was made that four Unit 2 ADS relief valve closure times did not meet acceptance criteria. Operators declared ADS inoperable and commenced shutting down Unit 2. Licensee commenced refuel outage, Q2R14.

March 11 Operators shut down Unit 1 to repair a faulty reactor protective system relay.

March 16 Operators initiated Unit 1 reactor startup.

March 17 Unit 1 turbine generator returned to service.

O1.2 Unit 2 Shut Down Due to Inoperable Automatic Depressurization System (ADS) Valves

a. Inspection Scope (93702)

The inspectors reviewed licensee surveillance procedures, and observed Unit 2 shutdown activities.

b. Observations and Findings

On February 28 at 4:20 p.m. central standard time, operators shut down the Unit 2 reactor due to four of five ADS valves having closing times in excess of the acceptance criteria. With the valves inoperable, Technical Specifications (TSs) required the reactor to be in hot shutdown within 12 hours and in cold shutdown within the following 24 hours.

During the shutdown engineering determined that the closing times for the ADS valves had met the acceptance criteria. However, two of the four ADS valves exhibited minor seat leakage after testing. Operations continued the reactor shutdown. The licensee planned to remove and test the two ADS valves exhibiting seat leakage. The licensee also planned to evaluate whether timing the valves in the closed direction was required.

c. Conclusions

The decision to declare the ADS valves inoperable due excessive closing times, and continue the shutdown due to seat leakage, was conservative. Unit 2 shutdown activities were in accordance with licensee procedures and were well executed.

O1.3 Control Room Inspections and Plant Area Walkdowns

a. Inspection Scope (71707)

The inspectors performed routine inspections in the control room and throughout the plant.

b. Observations and Findings

During the inspection period the licensee completed control room layout modifications designed to optimize the operators' ability to monitor the control panels. Prior to the commencement of the Unit 2 refuel outage, the licensee moved work control activities previously conducted in the control room to the adjacent communications center. This action eliminated most of the excess personnel traffic to the control room.

While inspecting the Unit 1 feedwater regulating valve area, the inspectors identified that the 1B feedwater regulating valve inlet isolation motor-operated valve (MOV) had developed a packing leak. The inspectors reported the leak to the unit supervisor who verified that the leakage exceeded the licensee's limits and subsequently wrote an action request (AR) to correct the condition. The inspectors also identified foreign material on top of the Unit 2 safety-related 4 kilovolt (kV) switchgear and notified the lead unit planner who initiated the necessary corrective action.

c. Conclusions

Control measures taken by operations to improve the working environment in the control room have been effective. The licensee's effort to provide more stringent control of room access, incoming phone calls, and general noise level was evident. Routine operator plant tours did not identify a packing leak on the 1B feedwater MOV or foreign material on safety-related switchgear.

O1.4 Unit 1 Reactor Protection System Relay Problem

a. Inspection Scope (93702)

The inspectors performed a follow up inspection of the failure of the 1-590-108D reactor protection system (RPS) relay. The inspectors reviewed the TSs and the operator logs, attended several root cause team meetings, and observed maintenance troubleshooting efforts.

b. Observations and Findings

On March 7 at 10:47 a.m. the 1-590-108D RPS relay deenergized unexpectedly causing a partial trip of the B RPS trip system In accordance with Quad Cities Operating Abnormal Procedure (QCOA) 500-1, "Partial Scram Actuation" operators inserted a full trip of the B trip system. No indications of a valid reactor trip signal were present. At 12:35 p.m. operators reset the B trip system for troubleshooting in order to determine the cause of the failure. Fourteen minutes later, after the cause could not be determined, operators again tripped the B trip system.

The RPS consisted of two trip systems, designated A and B. Each trip system consisted of two redundant trip logic channels (A1, A2, B1, B2). An automatic reactor trip required that both trip systems actuate, in a one out of two twice logic.

Every monitored reactor trip parameter provided input to each of the four trip logic channels. Any reactor trip input to the B1 trip logic would normally cause two relays to deenergize, 1-590-108B and 1-590-108D. The failure of the 1-590-108D relay rendered the B1 trip logic and associated instrument channels inoperable.

Quad Cities Operating Abnormal Procedure (QCOA) 500-1, "Partial Scram Actuation" instructed operators to trip the system affected, notify the shift engineer, and initiate corrective actions to determine the cause of the failure. A caution was included in the procedure and stated, "Do NOT reset a "half scram" until the cause is known AND permission to reset the scram has bean given by the shift engineer." The discussion section of the procedure stated, "During a partial scram actuation, operator response should be focused on plant safety requirements and NOT on investigating the RPS system."

Technical Specification 3.1.A required that the RPS instrumentation channels shown in Table 3.1.A-1 be operable. The action statement required that with the number of channels less than the minimum required that the inoperable channel and/or that trip system be placed in the tripped condition within one hour. Note (a) to table 3.1.A-1 stated that a channel may be placed in an inoperable status for up to two hours for required surveillance without placing the trip system in the tripped condition provided at least one operable channel in the same trip system is monitoring that parameter. The inspectors concluded that the maintenance troubleshooting effort to determine the cause of the relay failure did not constitute a required surveillance and that note (a) was not applicable in this situation.

Since the number of RPS instrumentation channels was reduced below the minimum required for some trip functions as a result of the relay failure, the licensee was required to take the specified action within one hour. The inspectors found that initial operator actions were in accordance with the requirement but the subsequent reset of the B RPS trip system was not in compliance with Technical Specification 3.1.A. This was considered a **Violation (VIO) (50-254/265-97002-01)**.

c. Conclusion

The inspectors found that initial operator actions were in accordance with the TS requirements but that the subsequent reset of the B RPS system with the relay inoperable was not in compliance with the TS. The inspectors concluded that the maintenance troubleshooting effort to determine the cause of the relay failure did not constitute a required surveillance and that note (a) was not applicable in this situation.

O1.5 Review of Operability Assessments

a. Inspection Scope (71707)

The inspectors reviewed the operability assessments performed within the last two years to determine which issues remained open.

b. Observations and Findings

The inspectors found that all remaining open operability assessments were being tracked by the licensee and were planned for resolution prior to Unit 2 startup. However, the inspectors identified one degraded system that was not on the list of open operability assessments.

In November 1996 the 2D RHR system discharge check valve failed to close after the pump was stopped which caused the low pressure coolant injection (LPCI) system to be inoperable for a short period of time. The inspectors found that PIF 96-3196 for this issue received an "issue screening" which was the first part of the operability determination process. The degraded check valve was determined to be operable with no further concerns and was not required to receive the second part of the review which was the operability determination. The inspectors agreed that the check valve and the system remained operable but concluded that concerns did exist since compensatory measures in the form of response instructions to operators were implemented to ensure system operability. The inspectors found the degraded check valve was scheduled for replacement during the current outage, and that the item was sufficiently tracked via the licensee's administrative tracking system.

The inspectors reviewed a sample of other issue screenings performed in the last year that did not have associated operability determinations and found no other open issues.

c. Conclusion

The inspectors reviewed open operability assessments and found all items to be adequately tracked by the licensee. However, the inspectors identified one degraded equipment operability issue that was not on the licensee's list of open operability issues.

O2 Operational Status of Facilities and Equipment

O2.1 Review of Operator Response to Abnormal Conditions

a. Inspection Scope (71707)

The inspectors reviewed the operators' response to various plant equipment problems and abnormal conditions. The inspectors also reviewed operations and maintenance priorities for degraded control room equipment.

b. Observations and Findings

I. Low Priority Given to an Operator Workaround

The inspectors noted operators having continual problems with the Unit 2 drywell equipment drain sump (DWEDS) outboard isolation valve. This valve

was one of two containment isolation valves for the DWEDS line which must be able to close to prevent release of radioactive material outside primary containment. Operators had trouble opening the valve on numerous occasions during the pumping of the DWEDS every four hours. On several occasions operators were required to crawl on top of the torus and hit the valve with a wrench to ensure the valve would open.

The inspectors found that no operability determination had been performed, nor had a problem identification form (PIF) been generated. The licensee had documented the deficiency with an action request. The control room operators informed the inspectors that the action request was Priority B1 which indicated that work would be started within 24 hours and continue around the clock. The inspectors questioned why no work was in progress and was subsequently told that the priority was B2. The action request was written on January 16. The inspectors raised the issue on January 30 and no work had been performed. The inspectors found that the electronic work control system (EWCS) action request screen indicated B1 priority in one place and B2 in another. However, neither priority was being met.

Further investigation revealed that engineering did not have a proposed solution to determine the cause of the valve sticking, and maintenance did not have any active work in progress or plan to fix the condition. On January 31, following the inspectors questioning of operability, operations supervision documented the problem with PIF 97-281 and forwarded the operability evaluation to engineering for completion. The initial operability determination that the valve was operable for closure was acceptable.

Engineering later determined through testing and evaluation that thermal binding was occurring in the valve in the open direction, but the same mechanism would not apply in the closed direction. Engineering recommended a two hour cycling of the valve to prevent thermal binding, and included the valve in the Unit 2 outage scope. The inspectors concluded that the resolution of the problem was adequate, but noted that operations response to a degraded equipment condition was weak.

ii. A Modification Package Resulted in Ventilation Problems

The inspectors questioned the unit supervisor as to whether or not the proper negative pressure was assured in the laundry tool decontamination (LTD) buildings following restoration of the ventilation. The unit supervisor investigated and determined that a discharge damper was closed when the damper should have been open. This condition prevented the proper negative pressure in the building. The inspectors found that the problems resulted from an inadequate procedure that did not identify the existence of the discharge dampers. This was due to the fact that the design modification that installed the ventilation system had not been closed or authorized by operations before the building had been put into service. This was considered an **Unresolved Item (50-254/265-97002-02)** pending further

review of the modification work package and licensee procedures for authorizing modifications.

iii. Failure to Control Turbine Building Negative Pressure

The inspectors found several instances throughout the period where operators were not responsive to ventilation annunciators which had alarmed in the control room. In one case, operators took no corrective action for a service building ventilation annunciator because the annunciator appeared to be a phenomena associated with the infrequently run train B control room ventilation. In another case, inspectors identified that operators were not taking corrective action for a turbine building low differential pressure annunciator. The inspectors discussed these observations with station management who agreed that better sensitivity to annunciators was required. However, on March 7, inspectors found that the turbine building low pressure annunciator was again lit, turbine building pressure was positive, and operators were not trying to establish a negative pressure in the building. The unit supervisor indicated initially that this condition was acceptable because a turbine building door was open. The inspectors pointed out that having a turbine building door open and positive pressure in the turbine building could result in an unmonitored release of radioactive airborne material. The unit supervisor then took action to make turbine building pressure negative.

Annunciator procedure QCAN 912-5,C.2, "Turbine Building 1 Low DP," required operators to start another exhaust fan and check for open doors. Since all additional exhaust fans were out of service, operators could not take the specified action but allowed the turbine building door to be opened anyway. This was a **Violation (VIO) (50-254/265-97002-03)** of the implementing annunciator procedure.

c. Conclusion

Operators failure to properly maintain turbine building negative pressure in accordance with the annunciator response procedures which could have resulted in the spread of contamination within and outside the turbine building. This was a violation. Other operational problems included a weak response to degraded equipment and additional ventilation problems related to inadequate control of a modification.

O2.3 Fire Pump Inoperable In Excess of Administrative Limiting Condition for Operation

The inspectors noted that the licensee had entered a 7-day administrative limiting condition for operation (LCO) for the ½ diesel generator fire pump. The LCO was entered for repairs to components affecting the 1C circulating water bay, with the work initially planned for more than 20 days. The inspectors questioned operations and maintenance supervision to determine the scope of the work and the level of effort being expended to complete the work expeditiously. The inspectors found

that the work was initially planned to be performed on two shifts and not on weekends. After discussing the inspectors' concerns with prioritization of this work, the licensee increased the effort and focus on the work.

A recent licensee submittal regarding an individual plant examination for external events (IPEEE) revealed that the risk for core damage from external events could be as high as 5E-3, with fire being the highest contributor. Although the licensee was adding a modification to improve the risk posture, reactor operation continued with an inoperable fire pump for a period exceeding the LCO limit before the modification was installed. This action reduced the reliability of the fire system even though other actions had been taken to minimize this risk. The inspectors verified that the requirements of the LCO action statement were met, but concluded that the licensee's work prioritization did not adequately consider plant risk.

O2.4 Inspection Results of Emergency Diesel Generator System (71707)

The inspectors reviewed licensee procedures to ensure compliance with design basis, TSs, and Sections 8.3.1.6 and 9.5 of the updated final safety analysis report (UFSAR). The inspectors reviewed chemistry logs, inservice testing commitments, and surveillance requirements. The inspectors walked down mechanical portions of the emergency diesel generator (EDG) systems. The inspectors concluded, that for the areas reviewed, the licensee's EDG program met TS requirements. However, the inspectors identified weaknesses in the licensee's calibration program and program for trending power system indicator performance. (See Section M2.1).

O2.5 Failure to Control Required Compensatory Measures to Ensure System Operability

a. Inspection Scope

The inspectors reviewed the operability determination for the low pressure ECCS with the associated room coolers out of service.

b. Observations and Findings

The inspectors noted that all of the room coolers for the Unit 2 ECCS were taken out of service after Unit 2 reached cold shutdown conditions on March 1. Although the reactor was in cold shutdown, TS 3.5.B required two low pressure emergency core cooling subsystems to be operable unless the reactor vessel head was removed, the cavity flooded, the spent fuel pool gates removed, and water level maintained within the limits of TSs 3.10.G and 3.10.H. Since the vessel head was not yet removed or the cavity flooded, the inspectors questioned the operability of the required systems with the room coolers out of service.

The inspectors reviewed the licensee's written operability assessment from PIF 95-1976 and found that it was adequate, but noted that several compensatory measures included with the justification had not been incorporated into procedures. The inspectors concluded that the required ECCS systems remained operable with the room coolers out of service and that no TS violation had occurred. The

inspectors reviewed UFSAR Sections 6.3.2.1 and 6.3.2.2 which described room cooler operation as needed to maintain the room temperatures below the qualification temperature of the components that are required for safe shutdown of the plant. The UFSAR did not contain any information regarding ECCS or room cooler requirements during shutdown conditions.

The compensatory measures included monitoring residual heat removal room temperatures, maintaining additional pumps available if a room cooler was out of service, and only removing the room coolers from service with the reactor in cold shutdown. The inspectors found that none of these compensatory measures were proceduralized.

c. Conclusion

The licensee failed to ensure that the proper compensatory measures were in place to control ECCS system operability without room coolers during shutdown conditions. The inspectors did not identify any situations in which the room coolers were removed from service prior to achieving cold shutdown conditions. However, lack of procedural controls to ensure operability during all operational modes was considered a weakness in the operability determination process.

O4 Operator Knowledge and Performance

O4.1 High Pressure Coolant Injection Initiation During Testing

a. Inspection Scope (71707)

The inspectors reviewed operator response to an inadvertent start of Unit 2 high pressure coolant injection (HPCI) pump during surveillance testing. The inspectors reviewed the emergency notification system (ENS) report, the sequence of event recorder, the UFSAR Sections 15.1 and 15.5. The inspectors spoke to operators and members of the investigative team assembled to review this event.

b. Observations and Findings

With Unit 2 at about 91% power, instrument technicians performing a Quad Cities Instrument Preventive Maintenance test(QCIPM), QCIPM 100-10 "Refuel Outage ECCS Instrumentation Check Prior to ECCS Logic Test," initiated HPCI causing about 50 gallons of cold water to be injected into the feedwater system. Injection of a sufficient amount of cold water into an operating reactor would have resulted in addition of positive reactivity to the reactor core. Operators received annunciators indicating a start of the Unit 2 HPCI pump. Operators did not expect the pump to start as a result of testing, and secured the pump after determining that plant conditions did not warrant use of HPCI. The operators did not detect any changes in power or reactor vessel water level as a result of this event. The licensee documented this condition on PIF 97-0549 and formed a multi-disciplined team to investigate the causes of this event. The investigative team determined that the root cause of this event was an inadequate procedure. The procedure was written

to be performed during refueling or shutdown mode and not during power operations.

The team identified that the surveillance procedure was not appropriate for the plant conditions and multiple barriers designed to prevent this type of event had failed. An independent review of the procedure by various personnel (maintenance scheduler, foreman, and unit supervisor) failed to prevent the event from occurring. All personnel relied on comparing the QCIPM procedure to an existing procedure performed during power operations instead of reviewing the electrical drawings. A review of electrical drawings would have determined that the QCIPM procedure would initiate HPCI. Planned corrective actions for this event included revising QCIPM 100-10 prerequisites, reviewing a sampling of procedures to ensure that assumptions made in 50.59 evaluations were included in procedure prerequisites, and more clearly explaining management expectations for first line supervision responsibilities.

The inspectors concluded that the immediate operator actions to secure HPCI were appropriate. The inspectors also concluded that the HPCI system performed as expected under the circumstances. However, the inspectors considered performance of QCIPM 100-10, "Refuel Outage ECCS Instrumentation Check Prior to ECCS Logic Test," during power operations to be a **Violation (50-265-97002-04)** of 10 CFR 50 Appendix B, Criterion V. Instructions, Procedures and Drawings. A 10 CFR 50.59 safety evaluation written for the procedure required QCIPM 100-10 be performed with the unit shutdown, and the procedure was not appropriate for performance with the reactor at power.

c. Conclusions

The inspectors noted operators quickly assessed that HPCI was not required and appropriately secured HPCI. Additionally, operators had previously identified that scheduled activities were incompatible with existing plant conditions. As a result, several days prior to this event, the licensee documented an adverse trend in scheduling activities on trend PIF 97-0486. The weaknesses identified in scheduling activities is an **Inspector Followup Item (IFI) (50-254/265-97002-05)**.

O8 Miscellaneous Operations Issues (92700)

O8.1 Review of Institute of Nuclear Power Operations Assessment

The inspectors reviewed the 1996 Institute of Nuclear Power (INPO) evaluation of Quad cities to determine if there were any safety issues which were previously unknown to the NRC. The report documented findings of similar programmatic problems to those previously identified by the NRC and the licensee.

O8.2 (Closed) Violation (50-254/265-96002-02): Primary Containment Violation. The inspectors identified that the licensee opened a manually operated valve during a local leak rate test. This allowed the torus to communicate with the reactor building basement with Unit 1 operating at full power. The licensee attributed this event to

a lack of knowledge of Generic Letter (GL) 87-09 with respect to application of TS 3.0.A. A policy statement was developed by the operations manager. Current license holders received training on various additional GL requirements. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707, 71707)

The inspectors observed work in the field and walked down the hydraulic control units (HCU) to assess the quality of maintenance activities.

b. Observations and Findings

I. Walkdown of HCUs

The inspectors identified a nitrogen supply tank for Unit 2 HCU 14-39 that was not properly mounted. Specifically, the tank upper mechanical joint connection bolt was backed off one-half inch. Operations documented the condition on a PIF 97-0384 and declared the HCU inoperable until maintenance repaired the joint. The HCU was worked during the previous outage. However, the licensee was not certain if the nitrogen supply tank mechanical joint was loosened during that activity. All other nitrogen supply tank joints were inspected satisfactorily. The inspectors determined that the licensee's actions were appropriate.

ii. Field Observations

During maintenance inspection activities, the inspectors observed the following:

- Engineering specified a local leak rate test (LLRT) procedure for post-maintenance testing of the Unit 1 A loop of containment spray. However, the LLRT procedure was written for the unit in a shutdown mode instead of an operating mode. A change to the procedure was required before testing could continue. Testing was delayed while in a TS LCO until the procedure was changed.

- As part of a modification to the reactor building fire main, a blank flange was removed and a new valve was to be installed. However, the new valve would not fit onto the strainer housing since the strainer was one-half inch too long. The interference between the existing strainer and the new valve was not recognized by the work

package. The package was changed to trim the strainer. This also delayed work in a TS LCO.

- A work package for welding on a Unit 1 reactor water clean up (RWCU) valve 1-1201-133 specified an incorrect weld. The work package was changed to specify the proper welding procedure. This resulted in additional time spent with Unit 1 RWCU out of service.

c. Conclusions

The inspectors noted that work package deficiencies resulted in additional time spent in TS LCOs, or affected equipment used to support reactor operations.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Instrument Calibration Program Weaknesses

a. Inspection Scope (61726)

The inspectors reviewed portions of the licensee's instrument calibration program, operations surveillance procedures, and a site quality verification (SQV) corrective action record (CAR). The inspectors reviewed codes and standards committed to by the licensee.

b. Observations and Findings

The inspectors identified process radiation monitoring support equipment instrumentation that was not included in a calibration program (Inspection Report 50-254/265-96020, Section R2.1). The inspectors also identified indicators monitored by operators during monthly surveillance testing of the emergency diesel generators that were not included in a calibration program. The licensee planned to calibrate both local and remote power system meters when calibrating other power system components. However, the licensee stated that local indicators logged during EDG surveillance testing were not required to be calibrated by Quad Cities Instrument Procedure (QIP) 100-11, "Calibration of Instruments used by Operations in Performing Surveillance Requirements," since the indicators were used for trending purposes and were not used in determining equipment operability.

SQV documented a level 1 corrective action request (CAR) on CAR 04-97-004 that the control room narrow range reactor pressure indicator, control room emergency diesel generator frequency and voltage indicators, and secondary containment differential pressure indicators were used by operators to determine equipment operability, but were not included in a calibration program.

The licensee also found the Unit 1 EDG frequency meter was out of calibration and documented the discrepancy on an out of tolerance report as required by procedure. However, the inspectors noted out of tolerance reports were neither tracked nor trended. As a result, adverse trends for electrical power instrument calibrations

may not be adequately identified. The licensee planned to document future power system meter discrepancies on PIFs.

c. Conclusion

Both the inspectors and licensee-identified indicators used by operators to determine equipment operability and also used for equipment trending that was not included in a calibration program. The inspectors considered resolution of the instrument calibration program to be an **Inspector Followup Item (50-254/265-97002-06)** pending review of licensee's corrective action system results.

M2.2 Containment Atmosphere Monitoring System Maintenance

a. Inspection Scope (62707)

The inspectors observed corrective maintenance activities, reviewed maintenance history on the 1B containment atmosphere monitor (CAM), and reviewed the UFSAR Section 6.2.5.2.

b. Observations and Findings

The CAM system was designed to be used post-accident to monitor hydrogen and oxygen levels in containment. The 1B CAM system was declared inoperable on January 24, 1997, after the oxygen analyzer failed the weekly surveillance test. The licensee entered TS LCO 3.2.F which required the system to be restored or the reactor shut down in 30 days.

During the troubleshooting effort, maintenance workers encountered numerous problems with the system not related to the observed failure mode. Work continued without resolving the problems until day 18 of the LCO before a root cause investigation team was assembled. At this point, the maintenance supervisor had contacted the vendor who was on site assisting the maintenance workers. On day 19 of the LCO the problems were corrected and the system restored to an operable status. The inspectors concluded that assembly of the team was slow and had little impact on the final outcome of this maintenance activity.

The cause of the failure was determined to be a bad oxygen analyzer cell in combination with a failed regulator. The maintenance team also found at least four other degraded parts, including other regulators in the system. The licensee sent the failed regulators and oxygen analyzer cell off site for failure analysis. At the conclusion of the inspection period, the licensee did not have the results of those analyses.

After reviewing the maintenance history for the 1B CAM system, the inspectors found that multiple regulator problems had occurred in the past. After each failure event regulators were replaced, however no root cause for repeat failures was performed. Furthermore, in the maintenance history, the inspectors found several failures attributed to water intrusion in the system. A design change to eliminate

this longstanding problem was planned for 1998 and compensatory measures to periodically drain water from the system were recently established.

The inspectors reviewed the CAM system monitoring for the maintenance rule (10 CFR 50.65). During the most recent assessment in December 1996, the licensee exceeded the reliability criteria of no more than two failed surveillances per refuel cycle on the Unit 2 CAM system. Train A experienced two failed surveillances and Train B experienced one failed surveillance. At that time, the system was reclassified as potential (a) (1). However, the system engineer recommended that the classification remain (a) (2) and submitted a reliability criteria change to the site maintenance rule coordinator to allow no more than three failed surveillances per refuel cycle. The rationale for the criteria change was that the refuel cycle had changed from about 18 months to 22 months, no more than two failed surveillances per train occurred, and none of the three failed surveillances in question were categorized as maintenance preventable functional failures (MPFF). At the end of the inspection period, the criteria had not been revised and no action had been taken to reclassify the system as (a) (1).

The inspectors reviewed the licensee's list of maintenance rule functional failures (MRFF) for July 1993 through December 1996. Seventeen MRFFs were documented for both Unit 1 and Unit 2 CAM systems. Two of the seventeen failures were identified as MPFFs. The inspectors identified several other failures on the list which appeared to be maintenance preventable and disagreed with the licensee's application of the MPFF definition. The cause of 3 of the 17 failures was unknown and yet the events were not categorized as MPFF. Two additional failures were attributed to aging power supplies and were also not coded as MPFF. The inspectors found that the licensee's root cause investigations into past failures were not detailed enough to identify events as MPFFs.

The inspectors concluded that the root cause of repetitive CAM system problems and failures had not been identified, but that repetitive regulator problems and water intrusion were longstanding issues that had not been resolved. Additionally, the inspectors identified problems with the licensee's implementation of the maintenance rule for this system, specifically the identification of failures as maintenance preventable and the failure to promptly reclassify the Unit 2 CAM system to an (a) (1) status. The inspectors planned to follow up on the licensee's root cause assessment of the most recent failures and the classification of the Unit 2 CAM system under the maintenance rule and consider this to be an **Unresolved Item (50-254/265-97002-07).**

c. Conclusion

The inspectors had concerns with the licensee's implementation of the maintenance rule, specifically the identification of MPFF events and the failure to promptly evaluate the Unit 2 CAM system status as (a)(1).

The inspectors also concluded that long-standing issues regarding repetitive regulator failures and water intrusion in the CAM system had not been resolved and

although the immediate problems were corrected and the system declared operable, the root causes of the system failure had yet to be fully addressed. In addition, an excessive amount of LCO time was used before additional maintenance resources were applied to repairs.

M2.3 Miscellaneous Material Condition Issues (71707)

The inspectors noted that continued equipment problems affected reactor operations and resulted in an early shutdown for refueling for Unit 2 and a forced shutdown for Unit 1. Below are several items identified by the licensee and the inspectors that affected plant operations:

The inspectors noticed that a number of valves on the Unit 2 control rod drive HCUs had rusty flange bolts. The deteriorating condition of these valves was not included in a problem tracking system, such as an action request.

Two Unit 2 intermediate range monitor (IRM) systems were failed prior to the unit shutdown. A third IRM failed during the shutdown.

A Unit 1 turbine sealing steam valve developed a leak. Repairs were performed during the forced outage.

The Unit 2 DWEDS containment isolation valve was difficult to open. The cause was identified as thermal binding.

A Unit 1 RPS relay failed. The licensee made a conservative decision to shut the unit down to investigate and repair. The relay was replaced during the forced outage.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-254/265-95010-02: Solenoid-Operated Valve Improperly Mounted. The inspectors identified a safety-related solenoid-operated valve that was not mounted in accordance with vendor instructions. The licensee remounted the solenoid and verified valve operability. The licensee verified proper installation of similar solenoid-operated valves accessible during power operations. No other deficiencies were noted. Procurement, maintenance, and engineering personnel received training on the necessity of maintaining proper orientation of solenoid-operated valves. This item is closed.

III. Engineering

Engineering and Technical Support (71707, 37551)

E2 Engineering Support of Facilities and Equipment

E2.2 Facility Adherence to the Updated Final Safety Analysis Report

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
O2.4	8.3.1.6	EDG Systems
O2.4	9.5	EDG Auxiliary Systems
O2.5	6.3.2.1, 6.3.2.2	ECCS Room Coolers
O4.1	15.1, 15.5	Inadvertent HPCI Actuation
M2.2	6.2.5.2	CAM System

For the sections reviewed, no issues of plant configuration of UFSAR accuracy were identified.

E7 Quality Assurance in Engineering Activities

E7.1 Program Weaknesses in Evaluation of Part 21 Issues

a. Inspection Scope (37551)

The inspectors reviewed the PIF process to determine how the licensee implemented 10 CFR 21, "Reporting of Defects and Noncompliance."

b. Observations and Findings

The licensee documented a failure of the shared EDG to start on November 4, 1995, on PIF 95-2795. The PIF was reviewed by the event screening committee (ESC) the following day and determined not to be a potential Part 21 reportable event. Subsequent evaluation determined the shared EDG failed to start due to a defective part. The inspectors determined the licensee evaluated and correctly concluded that the defective part did not have Part 21 applicability. However, the inspectors were concerned the licensee's ESC prematurely evaluated Part 21 aspects prior to identifying defective parts as the cause for equipment failure. The inspectors spoke to the site quality verification manager who acknowledged the process vulnerability. However, no plans were committed to by the licensee to permanently address the issue.

c. Conclusions

The inspectors identified a vulnerability in the licensee's method of identifying and reporting of 10 CFR Part 21 issues. However, the inspectors did not identify any instances where 10 CFR Part 21 notifications were not made when required.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Licensee Event Report (LER) 50-254-93002, Rev. 1: Failure of Secondary Containment Test. The licensee added an additional corrective action for this LER. The inspectors reviewed the additional corrective action. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Protection Observations

a. Inspection Scope (71750)

The inspectors reviewed maintenance activities in the plant requiring support by radiological protection technicians (RPTs).

b. Observations and Findings

The inspectors observed the following radiological protection concerns:

The reactor building crane malfunctioned preventing workers from lifting the spare recirculation pump motor. The inspectors observed then notified the RPT of some workers loitering in radiation areas during the delay. The RPT then directed the workers into lower radiation areas until the crane was returned to service.

The inspectors also noted a RPT in charge of a job on the refuel floor who was outside of the work area, but within shouting distance of the workers. The inspectors questioned the ability of the RPT to control the job from a distance.

The inspectors observed a radiation worker inside a clean area leaning over a contamination boundary against a pillar in a contaminated area. The inspectors notified a RPT supervisor who corrected the individual. The inspectors were concerned that the individual did not respect the contamination boundary and the radiological deficiency was not detected by the two RPTs on the job. There was no spread of contamination into the clean area from this event.

A shoe contamination event occurred during a walkdown of the area above the Unit 2 drywell equipment hatch. A repeat event occurred the next day, after radiation protection personnel were informed and the area had been cleaned.

c. Conclusions

The inspectors identified some RPTs lacked good command and control of radiological aspects of the work assigned. This could have resulted in an increase in dose to workers and the potential to spread contamination into clean areas.

R4 Staff Knowledge and Performance in Radiological Protection and Chemistry Controls

R4.1 Observations of Simulated Exercise of High Radiation Sampling System

a. Inspection Scope (71750)

The inspectors observed an emergency exercise which involved a simulated use of the high radiation sampling system (HRSS).

b. Observations and Findings

The inspectors noted that the sampling teams' performance during the drill was good. While the drill did not involve actually taking samples, all individuals involved simulated in detail the actions that would be taken to obtain a reactor water sample under post-accident conditions. The chemistry technicians and the HRSS chemist were knowledgeable of the procedures and the equipment. The HRSS building was adequately equipped with the necessary supplies. The sample was obtained and processed in the required time.

c. Conclusions

The inspectors concluded that the HRSS drill was successful and that personnel performance was good.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on March 14, 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
A. Chernick, Regulatory Assurance Supervisor
D. Cook, Operations Manager
J. Hoeller, Independent Safety Engineering Supervisor
J. Hutchinson, Site Engineering Manager
W. Lipscomb, Work Control Superintendent
M. Wayland, Maintenance Superintendent

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 627070:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/265-97002-01	VIO	Unit 1 RPS relay problem
50-254/265-97002-02	URI	inadequate modification closure resulted in ventilation problems
50-254/265-97002-03	VIO	failure to control turbine building negative pressure
50-254/265-97002-04	VIO	high pressure coolant injection system initiation during testing
50-254/265-97002-05	IFI	weaknesses identified in scheduling activities
50-254/265-97002-06	IFI	instrument calibration program weaknesses
50/254/265-97002-07	IFI	containment atmosphere monitoring system maintenance

Closed

50-254/265-96002-02	VIO	primary containment violation
50-254/265-95010-02	VIO	solenoid-operated valve improperly mounted
50-254/265-93002, Rev. 1	LER	failure of secondary containment test

LIST OF ACRONYMS USED

ADS	Automatic Depressurization System
AR	Action Request
CAM	Containment Atmosphere Monitoring
CAR	Corrective Action Record
ComEd	Commonwealth Edison Company
DP	Differential Pressure
DWEDS	Drywell Equipment Drain Sump
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
ESC	Event Screening Committee
EWCS	Electronic Work Control System
GL	Generic Letter
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
HRSS	High Radiation Sampling System
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operations
IPEEE	Individual Plant Examination for External Events
IRM	Intermediate Range Monitors
kV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LPCI	Low Pressure Coolant Injection
LTD	Laundry Tool Decontamination
MOV	Motor-Operated Valve
MPFF	Maintenance Preventable Functional Failure
MRFF	Maintenance Rule Functional Failure
PDR	Public Document Room
PIF	Problem Identification Form
QCAN	Quad Cities Annunciator Procedure
QCIPM	Quad Cities Instrument Preventive Maintenance
QCOA	Quad Cities Operating Abnormal Procedure
QIP	Quad Cities Instrument Procedure
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPT	Radiation Protection Technician
RWCU	Reactor Water Clean Up
SAR	Safety Analysis Report
SQV	Site Quality Verification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation