U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No:	50-254/97014(DRP); 50-265/97014(DRP)
Licensee:	Commonwealth Edison Company (ComEd)
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	July 29 - September 22, 1997
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EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 and 2
NRC Inspection Report No. 50-254/97014(DRP); 50-265/97014(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers an 8-week period of resident inspection.

Operations

- The licensee identified that on several occasions, operators did not notify chemistry personnel of the need to perform more frequent sampling of the condenser offgas system. Similarly, operators failed to test five control rods on Unit 2 prior to raising power above 40 percent (Sections O1.1, O8.7 and M3.2).

- The inspectors identified some weaknesses in the licensee's method of counting 50.54(f) indicators (Sections O7.1 and E7.1).

Maintenance

- The inspectors found that poor maintenance work practices, including a violation of plant procedures, prevented correction of material condition problems with an LPCI check valve. Eventually a leak developed, and repairs resulted in approximately 1 person-rem additional dose, as well as operational challenges to the plant during a time of operation with a failed fuel bundle. Poor configuration control and weak understanding of the design requirements prevented proper alignment of drain valves and prevented operations personnel from resolving the problem in a timely manner before equipment had degraded (Section M1.1).

- The inspectors' review of the completed surveillance packages verified that the surveillance results were in compliance with the applicable TS requirements and UFSAR, but identified that inadequate operations personnel and supervisory review of engineering surveillance packages had the potential to affect component operability decisions (Section M1.2).

- Maintenance activities resulted in operational disturbances and potentially hazardous personnel conditions. Maintenance supervision were hesitant to enter a near miss situation into the corrective action process. Eventually corrective action processes worked to the point of identifying hazardous conditions, but failed to come to effective problem resolution (Section M1.3).

- Maintenance activities on the Unit 1 gland steam condenser (GSC) level control valves (LCVs) were conducted poorly. Problems with parts support, work package preparation, planning, troubleshooting guides, work history, and work documentation led to cycling Unit 1 power levels, increased operator burden, and over 3 person-rem additional radiation exposure (Section M1.4).

- The inspectors identified several concerns regarding test control during the performance of the Unit 2 250 Vdc battery modified performance test. The recorded test acceptance criteria was incorrect and the licensee could not determine where the information was obtained. Also, several potential preconditioning issues were identified which could have affected test results. The inspectors concluded that the battery test results were acceptable despite the identified test control weaknesses (Section M3.1).

- Even though most surveillances were completed within the critical date, the inspectors noted a continued adverse trend of missed surveillances. The inspectors concluded that there were multiple reasons for the missed surveillances. Some of these reasons included defective procedures and/or poor scheduling of surveillances or human error (Section M3.2).

- The inspectors concluded that some TS surveillance requirements and acceptance criteria were not adequately incorporated into station surveillance procedures. The problems identified were with a small fraction of the total surveillance population, but the reviews were conducted on a sampling basis. This could indicate that further surveillance adequacy issues remain (Section M3.3).

Engineering

- The inspectors identified a lack of attention to detail in the design verification process of calculations for the 250 volt battery (Section E1.1).

- Poor communications between engineering, operations, and maintenance personnel were evident in backlog reduction efforts (Section E1.2).

- The licensee and inspectors identified weaknesses in some safety evaluations (Section E1.3).

- The inspectors identified that the licensee had not considered the instrument accuracy and sensing location in safe shutdown makeup pump system design basis calculations prior to incorporating the safe shutdown makeup system into the plant TSs. The licensee did not provide calculations and validate through testing that the surveillance test acceptance criteria bounded design basis flow and pressure requirements. This resulted in a violation (Section E1.4).

- The inspectors identified various equipment important to safety in an operable but degraded condition. There were no plans for how and when the equipment would be removed from the operable but degraded status (Section E2.1).

- The inspectors found some discrepancies in the reporting of engineering indicators used to support a 10 CFR 50.54(f) request for information (Section E7.1).

- The inspectors identified that a licensee commitment made in licensee event report (LER) 50-254/94002 to install a "B" control room emergency ventilation (CREV) hot gas bypass system had not been met. In August 1997, the inspectors reviewed the LER, spoke with engineering staff, and determined that the system had not been installed and that design work on the modification had essentially been stopped (Section E8.3).

Plant Support

- An error made by a chemistry technician resulted in a missed TS required surveillance (Section R8.1).

- Poor initial troubleshooting efforts and other maintenance problems, such as improper governor installation, prevented the completion of fire pump work within the administrative LCO time limits. Later troubleshooting resulted in discovery of a long standing problem with the fire pump. Justification for jumpering out fire pump alarms was poor, and operator compensatory actions were not adequately spelled out (Section F1.1).

- The inspectors noted an overall lack of sensitivity to fire protection issues. A number of equipment problems resulted in administrative LCO time limits being exceeded. Some equipment was inoperable in excess of 3 years, with planned modifications to repair the problems recently canceled or changed. The inspectors noted a lack of rigor in assuring the required fire watches were established, and a violation was cited. Problem identification forms were not effective in focusing management attention on the fire protection problems. This all occurred in an environment where the licensee was aware of a relatively high fire risk at the station (Section F1.3).

Report Details

Summary of Plant Status

Unit 1 was at full power at the beginning of the inspection period. Fouling of the main condenser required the licensee to reduce power daily during off-peak hours to reverse flow through the main condenser. On September 11 operators reduced power to 450 MWe to troubleshoot and repair the "B" turbine gland seal condenser level control valve. On September 16, 1997, operators reduced Unit 1 power to about 14 percent to facilitate a drywell entry to restore the oil level on the 1A reactor recirculation pump. Power was held at 400 MWe while repairs were performed on the 1B gland steam condenser level control valve. Again, on September 21, operators reduced power to 450 MWe to troubleshoot and repair the "B" turbine gland seal condenser level control valve. The licensee returned the unit to full power operations at the end of the inspection period.

Unit 2 was operating at full power at the beginning of the period. A load reduction was conducted on August 6, 1997, for drywell entry to identify and isolate a packing leak to the drywell equipment drain sump from a core spray testable check valve. Another load drop was conducted on August 13, 1997, while the licensee performed a temporary repair on the 2A moisture separator drain tank vent flange. Power increases were rate-limited to prevent further degradation of a leaking fuel assembly. Hydrogen water chemistry was being tripped daily due to offgas oxygen control and offgas hydrogen sampling problems.

I. Operations

O1 Conduct of Operations

O1.1 Offgas Monitoring Sampling Less Frequent than Required by TSs

a. Inspection Scope (71707)

The inspectors reviewed operator logs, problem identification forms, and spoke to operators.

b. Observations and Findings

With the Unit 2 offgas explosive meter inoperable, operators requested that the chemistry department obtain grab samples of the offgas system once every 4 hours as required by TS Table 3.2.H-1. TS allowed relaxing the frequency to once per 8 hours if reactor power and offgas recombiner temperature were constant. However, at 10:15 p.m. on September 4, during flow reversal of the main circulating water system, the hydrogen addition system tripped which resulted in a small decrease in recombiner temperature. This condition required a return to once per 4-hour sampling requirements of the offgas system. Again on September 5 at 8:00 p.m. and at 11:40 p.m., the hydrogen addition rate changed, requiring more frequent sampling of the offgas system. Operators did not inform chemistry of the need to increase the offgas system sampling frequency from once per 8 hours to once per 4 hours. The licensee documented this condition on problem information form (PIF) Q1997-03415.

This was a Violation (50-254/97014-01a; 50-265/97014-01a) of TS Table 3.2.H-1. The licensee attributed this problem to procedural deficiencies since the system outage report does not address increased frequency of testing on decreased recombiner temperatures.

c. Conclusions

Operations, along with other departments, failed to meet TS surveillance requirements. Other missed or inadequate surveillances were discussed in Sections M3.2 and M3.3 of this report.

O2 Operational Status of Facilities and Equipment

O2.1 Safe Shutdown Makeup Pump System Walkdowns

a. Inspection Scope (IP 37551, 62707, 61726, 71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the safe shutdown makeup system (SSMP). The inspectors reviewed past and recently completed surveillance tests, QCOS 2900-01, "Quarterly Safe Shutdown Makeup Pump Flow Rate Test," maintenance work packages, and correspondence with the architect/engineering firm for the system.

b. Observations and Findings

Review of Surveillance Test Data

TS acceptance criteria were met according to the surveillance test. The acceptance criteria for this pump were in question due a design basis issue being evaluated by engineering (Section E1.4). Pump inservice test (IST) vibration readings had been running near the "alert" level for the past 3 years. The system engineer believed the cause of the vibration was pump misalignment. During recent maintenance activity, a condition concerning shaft tolerances was identified that could also have been a contributor to the higher vibrations. The licensee deferred corrective maintenance to address alignment and shaft dimensions to a future date.

Review of System Maintenance History

The general condition of the SSMP system was good, with the exception of pump performance. Earlier Sargeant and Lundy (S&L) engineering data showed that the SSMP was designed to supply 400 gpm at 1250 psig discharge pressure. Tests conducted shortly after the system was installed in the mid-1980s showed that the pump could perform at this level. Records showed that in 1987 the pump seized. Following seizure, some of the internal bushings were undercut. Subsequently, it appeared that the SSMP pump discharge pressures were typically lower than 1250 psig. Pressure readings ranged from 1220 - 1240 psig, with several results well below 1200 psig.

Correspondence from S & L to the licensee stated the licensee should check the accuracy of the installed instrumentation and inspect the pump internals for the cause of the loss in performance. The licensee's records indicated that the instrumentation was checked and found to be accurate. However, there were no records to indicate that pump internals were ever inspected. The licensee's corrective maintenance program was weak in that the limitations of the SSMP were not assessed. Subsequently, the licensee did not aggressively pursue the reduced pressure output of the pump which was very close to the limit of acceptance. This condition was documented on Section E1.4 of this report.

Review of Work Packages For Recent Maintenance Outage

The pre- and post-job briefing sheets in the reviewed work packages were of several different revisions. The earlier revisions did not contain control measures to assess rework afforded in the current work package revisions. Accurate identification of maintenance rework had been an ongoing problem at the station for some time. Consequently, the licensee had not effectively implemented the necessary controls, to identify and assess rework conditions into the pre-job briefing. The inspectors assessed this as an administrative weakness which was acknowledged by the licensee. There were no negative consequences to the plant in the cases noted.

c. Conclusions

The general material condition of the SSMP system was good with the exception of pump performance. Past conduct of maintenance monitoring was insufficient, as evidenced by the poor monitoring of maintenance history and limited action to correct degraded SSMP output pressure. There was no evidence that the vendor recommendations to inspect the pump internals were accomplished. In general, the licensee had given the SSMP system relatively low priority in addressing design and equipment issues.

O7 Quality Assurance in Operations

O7.1 Review of 50.54f Performance Indicators

a. Inspection Scope

The inspectors reviewed several of the licensee's performance indicators which were implemented in response to a 10 CFR 50.54f letter from the NRC to ComEd. The indicators included operator workarounds, human performance LERs, and failed TS pump and valve surveillances.

b. Observations and Findings

Operator Workarounds

The inspectors reviewed the performance indicator charts for the months of May and June and noted that the workdown curve had changed. On August 1, 1997, the inspectors obtained a list of scheduled work dates for all the open operator workarounds (OWA) and compared the OWA list with the workdown curve. The inspectors found that the workdown curve projected by the work control schedule did not match the workdown curve published on the indicator chart and also did not match the workdown curve projected by the Operations department.

The inspectors were concerned that the indicator goal of less than 10 percent deviation from the workdown curve did not appropriately measure progress in reducing the numbers of operator workarounds since the workdown curve was changed every month. For example, in May the projected number of OWAs for the end of June appeared to be 31. However, the actual number of OWAs at the end of June was 37, and the goal for June was changed to 34. Therefore, the licensee concluded that the goal was met since 37 was within 10 percent of 34. (Note that the temporary alteration workdown curve also changed from month to month). In the future, the licensee no longer planned to change the workdown curve monthly.

Human Performance Licensee Event Reports

The inspectors questioned the licensee about the goal for the number of human performance LERs. The goal established was less than or equal to two LERs per month. The inspectors noted that the numbers of human performance LERs from the licensee's graph for 1994, 1995, and 1996 were, respectively, 12, 8, and 17. Therefore, 2 human performance LERs per month could lead to a total of 24, which would indicate a serious decline from past performance. The licensee stated during the August 5, 1997, performance indicator meeting with NRC management that the rate of two LERs per month was used as a threshold for involving licensee corporate management and not intended to represent an acceptable level of errors.

Failed TS Pump and Valve Surveillances

While reviewing the data for this surveillance, the inspectors questioned the high number of monthly surveillances shown on the indicator chart. It appeared that over 3500 surveillances were performed in the month of June. The IST coordinator explained that control rod drive surveillances and scram time testing of control rods exercised up to 14 valves per control rod (177 total) which were individually counted in the total number of tests. Additionally, one physical performance of a procedure could account for numerous component tests (for example; leakage test, valve time test.)

The inspectors reviewed PIFs against the data collected for this indicator and found no discrepancies. All documented failed surveillances were counted appropriately. It should be noted that the total number of tests are tracked differently than the total number of failures. The failures were counted on a per component basis rather than the total number of test failures. Since the indicator was being tracked for 6 months prior to establishing a goal and no rate of failure was calculated, the inspectors concluded that there was no impact in counting the failures differently than the total number of tests. However, if in the future a failure rate was used as a goal, the counting methods would need to be reevaluated.

c. Conclusions

Even though the workdown curves did not accurately reflect the projected rate of reducing OWAs, the inspectors had noted that the overall number of OWAs had decreased over the past several months. The inspectors concluded human performance LERs and failed TS pumps and valve surveillance indicators were adequately counted.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-254/94010-00; 50-254/94010-01: Unplanned Scram of Control Rod During Surveillance. The surveillance generated a half-scram condition to the reactor protection system on Unit 2. Since a half-scram did not satisfy the logic required to produce control rod motion, control rods on the unit were not expected to move. However, Rod D-11 fully inserted. The licensee attributed this event to aged diaphragms in the 117 scram solenoid pilot valve (SSPV). The inspectors cited the licensee (Violation 50-254/94017-03; 50-265/94017-03) for ineffective corrective actions for repeat SSPV problems. The licensee subsequently replaced all SSPV diaphragms on both units. The inspectors have noted better control rod system performance. This item is closed.

O8.2 (Closed) LER 50-254/96001-00: "B" Control Room Emergency Ventilation System (CREVS) Inoperable Due to Inoperable Relay. An operator identified the "B" CREVS fan was spinning backwards indicating the fan dampers were open. How long this condition existed was unknown. Operators started the system to verify the system was capable of meeting its design function. The licensee attributed this condition to a failed relay. No root cause of the failed relay was identified. The licensee had no plans to periodically replace the contacts. The inspectors reviewed the licensee's corrective actions. This LER is closed.

O8.3 (Closed) Inspector Followup Item (IFI) 50-254/96002-03; 50-265/96002-03: Buildup of Debris on Trash Rack Resulted in Low Water Level Inside Intake Structure. The low intake water level condition resulted in the fire pumps becoming inoperable on January 23, 1996. Operators reduced power until the trash rack was cleaned and intake water level returned to normal levels inside the crib house. The inspectors were concerned that maintenance requests for the system were given a low priority, operators were not prepared to respond to the event in a timely manner, there was no method to determine water level inside the crib house and operators did not know what water level would render pumps incapable of providing flow due to cavitation.

The licensee responded by revising Quad Cities Operating Procedure (QCOP) 4400-04, "Traversing Trash Rake," to include a frequency of trash raking and included the minimum water levels in the bays to ensure various pumps would remain operable. Engineering confirmed that safety-related pumps would pass the required design flow should the river level drop to the Updated Final Safety Analysis Report (UFSAR) specified minimum level of 561 feet above sea level. However, for inservice testing purposes, the pumps would be declared inoperable should crib house water level drop below the level specified in QCOP 4400-04. In addition, the procedure required operators measure the water level inside the crib house if the trash rack was dirty and the trash rake was not operable. The method for measuring water level was to drop a weighted line until the water surface was contacted then measure the length of the line. The licensee changed Quad Cities General Procedure (QCGP) 3-2, "Control of Planned Reactivity Changes," to start TS required shutdowns in a more timely manner.

Operators continued to monitor trash rack conditions shiftly on rounds. The inspectors observed trash raking activities during the inspection period and noted the equipment worked satisfactorily. However, the inspectors noted the depth of water at the north end of the intake structure was less than 5 feet. The licensee plotted the depth of the water in front of the intake structure yearly and noted the silt buildup had increased. The licensee planned to have the area dredged in the future. The inspectors noted the silt buildup would not inhibit the proper operation of the safety-related pumps should river water level drop to the minimum UFSAR design water level of 561 feet above sea level.

The inspectors reviewed the licensee's root cause evaluation, corrective actions, and procedure changes. This item is closed.

O8.4 (Closed) LER 50-254/96006-00: TS 3.0.A Incorrectly Invoked. During shutdown of Unit 1, operators incorrectly entered into TS 3.0.A to perform a local leak rate test (LLRT). The LLRT vented the primary containment into secondary containment with the reactor at power. The inspectors cited a Violation (50-254/96002-02; 50-265/96002-02) for this issue.

The licensee attributed this event to an inadequate safety evaluation of the LLRT procedure and misinterpretation of the intent and application of TS 3.0.A. The inspectors reviewed the completed corrective actions listed in the LER. This item is closed.

O8.5 (Closed) LER 50-254/97001-00: Missed Operations Surveillances. On January 17, 1997, the licensee identified that two TS required surveillances were missed by control room operators. Control room operators changed from 8-hour shifts to 12-hour shifts, but control room logs were not modified to reflect the shift change. The licensee attributed this event to not adequately assessing the change to 12-hour shifts.

The two missed TS required surveillances exceeded the 12-hour limit plus the 25 percent allowed grace period. This was a Non-cited Violation (50-254/96020-01; 50-265/96020-01). The licensee implemented administrative controls to ensure the daily surveillances were not missed. This LER is closed.

O8.6 (Closed) LER 50-254/97008-00: Inadequate Operations Surveillance. The inspectors identified that the licensee failed to incorporate four residual heat removal service water (RHRSW) valves, which were not locked or otherwise secured in position, in a surveillance procedure. The licensee determined the surveillance deficiency was due to an inadequate procedure development and review due to human error. The inspectors determined this was a Violation (50-254/97011-03; 50-265/97011-03) of TS 4.8.A. The inspectors reviewed the licensee's corrective actions. This LER is closed.

O8.7 (Closed) LER 50-265/97008-00: Missed Control Rod Surveillance. On June 29, 1997, the licensee identified four control rod drives (CRDs) had not been adequately tested prior to their return to service. Similarly, on July 16, 1997, a fifth CRD was identified by the licensee as not having been adequately tested. The licensee declared the CRDs inoperable, inserted the rods, and satisfactorily tested the CRDs. The licensee attributed the missed post-maintenance tests to an ineffective tracking process and human error.

TS 4.3.D.1 required all CRD testing be completed prior to operating the reactor above 40 percent power. At the time of discovery, Unit 2 was operating above 40 percent power. The failure to test the five CRDs prior to increasing power on Unit 2 above 40 percent power was a **Violation (50-254/97014-01b, 50-265/97014-01b)** of TS 4.3.D.1. This LER is closed.

O8.8 (Closed) LER 50-265/97009-00: Control Room Operators Misread Abnormal Offgas Radiation Readings. This item was discussed in Inspection Report No.50-254/97011; 50-265/97011. The inspectors verified the control room operator logs had been changed as stated in the LER. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Activities

a. Inspection Scope (61726, 62707)

The inspectors reviewed and/or observed the following work requests (WR) activities and assessed the workers performance and compliance with plant requirements:

- WR 970081320 Unit 1 Emergency Diesel Generator Monthly Load Test
- WR 96003387401 Repair of 2A low pressure coolant injection (LPCI) air operated check valve.
- WR 970074951 Install/Remove Jumper in Unit 2 Rod Control System
- WR 970089249 Replace Unit 2 Main Steam Line Square Root Converters

b. Observations and Findings

On August 6, 1997, Unit 2 reactor power was reduced in order to troubleshoot and repair a valve packing leak in the drywell. The inspectors reviewed maintenance records and design information involving valve repacking activities to determine the appropriateness of the activity and the relationship to later packing failure. The inspectors' review determined that about 1 person-rem of exposure resulted from the downpower and repair activities for the 2A LPCI air operated check valve. The inspectors learned that the valve had previously been repacked in March 1997. Work Request 96003387401 was performed in March 1997 and included inspection and repair activities on LPCI Check Valve 2-1001-68a. After reviewing Work Request 96003387401, the inspectors discovered that the instructions in the maintenance request were not properly followed, and that the design of the packing leak-off line for the valve was not understood by plant personnel.

Work Request 96003387401 was written to allow for packing replacement. The supervisor involved changed the scope of the request to add packing rings vice replace packing, without properly changing the procedure. The work request referred workers to Attachment D of mechanical maintenance procedure Quad Cities Mechanical Maintenance (QCMM) 1515-07, Revision 7, "General Valve Packing Procedure." The job supervisor, when interviewed, indicated that although the package required changing out the inner and outer packing, he did not think that was necessary for the scope of the job. Instead of following or properly changing the procedure, the supervisor elected to only add rings to the outer packing, reasoning that there was no indication of packing leakage. However, the inspectors noted that the outer packing was being replaced because there was no adjustment left for tightening packing due to previous tightening efforts - an indication of packing leakage. By adding rings to the outer packing, the supervisor was also potentially adversely affecting the two stage packing with leak-off line arrangement. TS 6.8.A required applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, be implemented. This regulatory guide included administrative procedures dealing with procedure adherence and maintenance procedures dealing with safety-related equipment. Failure to follow procedure QCMM 1515-07 was a **Violation (50-265/97014-02)** of TS 6.8.A.

Following plant startup, the inner packing began leaking and eventually resulted in a unit downpower to isolate the packing leak. The packing leak was routed through a leak-off line which led to the drywell equipment drain sump. The excessive leakage required frequent pumping and recirculation of the sump. In addition, the high temperatures caused by the leak eventually led to a required change out of the sump pumps. These operator problems and the radiation dose received from the rework on this job could have been avoided had the original maintenance activity been conducted properly.

Once the leak was discovered, operators could not tell if the leak-off line was supposed to be open or closed. The leak-off line isolation valve 2-1001-64c for the 68a check valve was shown by piping and instrument diagrams (P&ID) to be open but required by Quad Cities Operating Mechanical (QOM) 2-0020-02, "U2 Drywell Valve Check List," procedure to be closed. The isolation valves had been listed as a discrepancy in the QOM check list, and left open. Failure to control plant configuration properly, and properly evaluate procedure changes led to the increased leakage into the drywell equipment drain sump. The licensee addressed the discrepancy by initiating Drawing Change Request 970179 to change the indicated position of the valve to "closed" on the P&ID. This licensee-identified and corrected violation is being treated as **a Non-Cited Violation (50-254/97014-03; 50-265/97014-03)** consistent with Section VII.B.1 of the NRC Enforcement Policy. The inspectors found through discussions with engineering and maintenance personnel that drywell equipment leak-off drain lines were initially installed to give early indication of packing leakage. Inability to maintain packing was cited as the reason for plant decisions to isolate the leak-off isolation valves, and even cap off the lines in some cases. Poor understanding of the design configuration led to a situation where degraded packing and an open drain line caused an excessive amount of drywell packing leakage.

c. Conclusions

The inspectors found that poor maintenance work practices including a violation of plant procedures prevented correction of material condition problems with a LPCI check valve and resulted in approximately 1 person-rem additional dose, as well as operational challenges to the plant during a time of operation with a failed fuel bundle. Poor configuration control and weak understanding of the design requirements prevented proper alignment of drain valves and prevented operations from resolving the problem in a timely manner before equipment had degraded. A non-cited violation was issued following licensee identification and resolution of the configuration control problem.

M1.2 Surveillance Observations

a. Inspection Scope

The inspectors reviewed and/or observed the surveillance activities listed below. The inspectors verified the surveillances were in conformance with the design basis of the facility and in compliance with TS.

QCOS 0300-01	Control Rod Drive Exercise
QCOS 1000-06	Quarterly Residual Heat Removal (RHR) Pump/Loop Operability Test
QCOS 6900-01	"Station Battery Weekly Surveillance" for March 11, 18, and 24, 1997, for the Unit 1 Safety-Related 250 Vdc Battery
QCOS 6900-02	"Station Battery Quarterly Surveillance" Performed on the Unit 1 250 Vdc Battery on March 14, 1997
QCOS 6900-02	"Station Battery Quarterly Surveillance" performed on the Unit 2 250 Vdc Battery on March 31, 1997
QCTS 0240-04	"Unit One (Two) Service Test 250 Vdc Safety Related Battery" Performed on the Unit 1 250 Vdc Battery in May 1996
QCTS 0240-06	"Unit One (Two) Modified Performance Test 250 Vdc Safety Related Battery" Performed on the Unit 2 250 Vdc Battery on April 7, 1997

b. Observations and Findings

During this review the inspectors identified concerns with the surveillance procedures pertaining to testing methodology and the acceptance criteria used in procedure Quad Cities TS (QCTS) 0240-06 "Unit One (Two) Modified Performance Test 250 Vdc Safety Related Battery," Revision 2. These concerns are discussed in detail in Section M3.1 of this report.

The inspectors also identified a concern with the review process of completed surveillances. Surveillance procedure QCTS 0240-06 did not require a review of the test results by on-shift operations personnel prior to declaring the 250 Vdc battery operable. The inspectors were concerned that only one level of review of completed surveillance packages could lead to unacceptable surveillance results not being identified in a timely manner prior to declaring a component operable. For example, TS surveillance QCTS 0240-06 performed on April 7, 1997, and discussed in Section M3.1 of this report, had an incorrect acceptance criteria for the battery capacity. The acceptance criteria was required to be noted in Step D.8 of the procedure each time the modified performance test was performed by engineering. The inspectors identified there was no operations review of the completed package; therefore, there was a missed opportunity to identify the incorrect acceptance criteria on April 7. The incorrect acceptance in this case did not result in an inoperable battery.

c. Conclusions

The inspectors' review of the completed surveillance packages verified that the surveillance results were in compliance with the applicable TS requirements and UFSAR, but that inadequate operations and supervisory review of engineering surveillance packages had the potential to affect component operability decisions.

M.1.3 Personnel Safety Problems

a. Inspection Scope

The inspectors reviewed plant response to two events involving maintenance activities which had a high potential for, but fortunately did not result in personnel injury.

b. Observations and Findings

In one case, on August 13, 1997, inspectors observed maintenance personnel conducting fire system surveillance Quad Cities Mechanical Maintenance Surveillance (QCMMS) 4100-32, "1/2A-4101 Diesel Driven Fire Pump Annual Capacity Test." Just prior to opening a fire test header isolation valve, two maintenance supervisors walked onto a catwalk over the circulating water discharge canal to test the structural integrity of devices installed to protect plant equipment from damage caused by high pressure water sprayed during the surveillance. When the valve was opened, high pressure water trapped in the line discharged into the discharge canal area and struck one supervisor, pushing him up against a safety railing and knocking his hard hat into the discharge canal. The procedure and maintenance supervision failed to adequately protect personnel from injury during the surveillance activity. Additionally, this near-miss incident was not documented on a PIF until prompted by the quality and safety assessment manager the following day.

Corrective action for the event was also inadequate in that PIF Q1997-3188, written to address the problem, did not adequately address the safety issue involved. The PIF was closed to a data point with the understanding that a change to the surveillance procedure, including an additional caution statement, would be made. However, on September 2 when the inspectors reviewed the QCMMS, a correction to the procedure had not been made. In addition, the PIF had identified that the likely cause of the pressure surge when opening the system was water trapped due to valve leakage into the header. But corrective action to fix the valve leakage had not been taken or initiated as of August 29 when the inspectors informed plant management. On September 2 the valve work was not performed and the procedure change had not been implemented, meaning that no effective corrective action had yet been taken. Following NRC discussions with management, operators hung caution tags on the valve in question to assure personnel safety until the issue was resolved.

On September 2, 1997, the inspectors observed control room operations and maintenance staffs respond to an event in which workers cut a live 13.8 kV electric line by accident using a backhoe. This event was very similar in nature and consequences to another 13.8 kV line cut caused by maintenance on September 9, 1996, and documented in Inspection Report No.254/96012; 50-265/96012. Operators properly addressed the numerous annunciators and equipment changes caused by the high voltage line cut, but were distracted from routine control room duties during the event. The inspectors found that tne workers had made attempts to locate energized lines in the dig area. The licensee was investigating the cause of the event, using PIF Q1997-03367 as the tracking mechanism.

c. Conclusions

The inspectors concluded that maintenance activities resulted in operational disturbances and potentially hazardous personnel conditions. Maintenance supervision were hesitant to enter a near miss situation into the corrective action process. Eventually corrective action processes worked to the point of identifying dangerous conditions, but failed to come to effective problem resolution.

M1.4 Poor Gland Seal Level Control Valve Maintenance

a. Inspection Scope

The inspectors reviewed work packages and work in progress to determine the effectiveness of maintenance in repairing the "1B" gland steam condenser (GSC) level control valve (LCV.)

b. Observations and Findings

The gland seal condenser level control valves have been chronic maintenance problems at Quad Cities in the recent past. The Unit 2 startup from the Q2R14 refueling outage was troubled by GSC LCV problems. The 1A GSC LCV had been tagged inoperable since April 1997. Maintenance history showed problems with the 1B valve in November 1996 and then in January 1997, June 1997, and then August through September 1997. Radiation dose to workers had been high when failures occurred because the area of the LCV was a high radiation area during power operations. The system was designed with redundancy, so when one LCV failed, the other may be put into service. However due to inability to maintain the valves, Quad Cities has been operating Unit 1 with only one operable LCV. Thus when the 1B valve began to fail in August 1997, operators were forced to go into the heater bay to manually control GSC level. Inability to control level could have resulted in gland steam leaks in the heater bay on high level, or degraded main condenser vacuum on low level.

Operations normally reduced reactor power in order to lower radiation exposure to operators and maintenance workers when a GSC LCV problem was experienced. Although as low as reasonably achievable (ALARA) practices were normally followed for the repairs, the number of repair attempts led to high overall exposures to personnel in August and September. Radiation exposures of up to 3.5 person rem were experienced for all the various heater bay entries involved.

The inspectors noted that the initial work package for repairing the 1B GSC LCV lacked a troubleshooting plan. Several attempts were made to repair the valve by tuning the controller, repairing air leaks, and repairing a valve diaphragm, before a comprehensive plan was a developed by a team. The inspectors spoke with the maintenance superintendent who indicated that this effort did not meet his expectation for a troubleshooting plan. That expectation had been expressed earlier following poor maintenance on diesel generator air start motors.

The inspectors noted that some of the entries in Work Package 960102229 lacked detail. Previous attempts to repair the LCV were recorded with insufficient history to determine the problem with the equipment. During the repair attempts on the 1B valve, maintenance and engineering personnel also attempted to repair the 1A valve. Partly due to insufficient documentation of the status of the 1A valve, there was significant confusion about the status of the valve, leading personnel to spend effort on the repair when a return to service was unlikely.

Parts support was also a problem. Technicians found that parts on order to repair the 1B valve were incorrect. Once the 1B valve internals were removed, incorrect parts were also found there. The inspectors were also informed that parts to repair both the 1A valve and the 1B valve were not available. The inspectors questioned why a critical balance of plant component with poor repair history did not have ample spare parts available to fix both the 1A and 1B LCV, especially considering the two active maintenance requests written against LCVs on Unit 1 and Unit 2.

c. Conclusions

Maintenance activities on the Unit 1 GSC LCVs were poor. Problems with parts support, work package preparation, planning, troubleshooting guides, work history, and work documentation, led to cycling Unit 1 power levels, increased operator burden, and additional radiation dose.

M3 Maintenance Procedures and Documentation

M3.1 Quad Cities Technical Staff Procedure 0240-06, "Unit One (Two) Modified Performance Test 250 Vdc Safety Related Battery"

a. Inspection Scope (61726)

The inspectors had previously witnessed portions of the Unit 2 modified performance test for the Unit 2 250 volt direct current (Vdc) safety-related battery conducted in accordance with QCTS 0240-06 on April 7, 1997 (see Inspection Report No. 50-254/97006(DRP); 50-265/97006, Section M2.3). During this inspection, the inspectors further compared the completed test package to the designed load duty cycle of the battery to verify that the test requirements conformed to TS 4.9.C, UFSAR 8.3.2.1, and S&L battery calculation, "PMED 891377-01", Revision 10. The inspectors had specific observations pertaining to PMED 891377-01 which are discussed in Section E1.1 of this report.

b. Observations and Findings

The review of the completed April 7, 1997, modified performance test package (QCTS 0240-06) identified several issues, some pertaining to methodology and others to acceptance criteria. The updated TS, issued in the fall of 1996, allowed the licensee to conduct a modified performance test on the 250 Vdc battery in lieu of a separate service test (based on the battery's design duty cycle) and a performance test (measures battery capacity). The requirements for a modified performance test is defined in standard Institute of Electronic of Electrical Engineers (IEEE) 450-1995, " IEEE Recommended practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for

Stationary Applications." The licensee issued procedure QCTS 0240-06, "Unit One (Two) Modified Performance Test 250 Vdc Safety Related Battery," to define the testing methodology for the new TS modified performance test.

The inspectors identified the following concerns with the April 7 modified performance test and procedure QCTS 0240-06:

- Step D.8 of procedure QCTS 0240-06 required the individual performing the test to determine the minimum acceptable battery capacity from the latest revision of the direct current (dc) Electrical Load Monitoring System (ELMS) and record the number in the step. The minimum acceptable battery capacity acceptance criteria recorded for the April 7 test was 70 percent. This acceptance criteria was not correct. The minimum acceptable capacity should have been 80 percent or the margin calculated from the design load profile for the battery, whichever is greater (Step F.4). In the case of the April 7 modified performance test, based on the current capacity margin as defined in the design load profile, the minimum capacity acceptance criteria should have been 80 percent. The completed modified performance test determined that the battery's capacity was 100 percent; therefore, the incorrect acceptance criteria of 70 percent did not adversely impact the operability of the battery. The licensee could not determine where the 70 percent acceptance criteria was obtained. The failure to have the correct acceptance criteria for the Unit 2 safety related 250 Vdc battery modified performance test is considered a **Violation (50-254/97014-04; 50-265/97014-04)** of 10 CFR 50, Appendix B, Criteria XI, "Test Control."

- Section B of procedure QCTS 0240-06, titled "Discussion," stated the initial conditions for the modified performance test should be identical to those specified for a service test. Also, IEEE 450-1995, Section 5.4, had a similar statement. Procedure QCTS 0240-06 referenced standard IEEE 450-1987 which was incorrect since it did not address modified performance testing. For the purpose of this inspection, the inspectors utilized IEEE 450-1995 as the recognized standard for the modified performance test.

  The purpose of a service test was to determine if a battery could provide the required current within specified voltage parameters during the design load profile. Standard IEEE 450-1995, Section 6.6, stated that the battery condition for the service test be in an "as found" condition. For example, battery connections and resistance readings can be checked prior to the test, but no corrective action would be taken unless there was a possibility of battery damage. The inspectors identified the following concerns in this area:

  (1) On March 31, 1997, the licensee performed TS 4.9.C.2. Quad Cities Operations Surveillance (QCOS) 6900-02, "Station Battery Quarterly Surveillance." During the surveillance, corrosion was identified at cell connections 70, 73, and 90. Procedure QCOS 6900-02 required the corrosion to be cleaned by performing procedure Quad Cities Electrical Preventive Maintenance (QCEPM) 0100-01, "Station Battery Systems Preventive Maintenance." The inspectors determined that the corrosion was cleaned from the affected cells. The inspectors reviewed the records associated with the recording of the cell resistance (Attachment F of

procedure QCEMP 0100-01) and noted that only "as found" resistance readings were recorded and not also the "as left." The inspectors were concerned that the battery was not tested on April 7 in the "as found" condition as recommended by IEEE 450-1995.

(2) The modified performance test procedure QCTS 0240-06, Revision 2, did not require that all battery connections have the correct resistance. The inspectors determined that the last time the resistance of the battery connections were checked was in May 9, 1996, approximately 11 months prior to the April 7, 1997, modified performance test. The resistance was checked as required by TS 4.9.C.3 using procedure QCEMP 0100-01, "Station Battery Systems Preventive Maintenance." The TS surveillance was to be performed every 18 months. The inspectors were concerned that the "as found" condition of the battery was not being ascertained prior to performing the modified performance test as recommended by IEEE 450-1995.

- A prerequisite, defined in Step D.6, stated that if necessary, locate temporary heaters in the battery room to maintain adequate electrolyte temperature. The procedure did not identify the adequate electrolyte temperature (note: TS 4.9.C.2c. requires the average electrolyte temperature to be above 60°F). Even though heaters were not used prior to the April 7 modified performance test, the inspectors were concerned that using heaters in the future would be preconditioning the battery for the portion of the modified performance test pertaining to the 1 minute peak testing discharge rate (920 amps). Increasing the electrolyte temperature improves the battery's performance and could mask a degraded battery and compromise the requirement of testing the battery in an "as found" condition. This concern was discussed with the licensee, and procedure QCTS 0240-06 will be revised to delete placing heaters in the battery room to elevate the battery's electrolyte temperature prior to the test.

c. Conclusions

The inspectors identified several concerns regarding test control during the performance of the Unit 2 250 Vdc battery modified performance test. The recorded test acceptance criteria was incorrect and the licensee could not determine where the information was obtained. Also, several potential preconditioning issues were identified which potentially could have affected test results. The inspectors concluded that the battery test results were acceptable despite the identified test control weaknesses.

M3.2 Missed Surveillances

a. Inspection Scope (92701, 61726)

The inspectors reviewed recent PIFs and LERs associated with missed surveillances.

b. Observations and Findings

The inspectors noted multiple instances of missed surveillances identified by both the licensee and the inspectors over the past year. In the winter of 1997, the inspectors identified two violations where control room ventilation surveillances were missed. These were due to inadequate review of existing surveillance procedures to ensure the new TS upgrade program (TSUP) requirements were included. More recently, the inspectors identified two non-cited violations (NCVs) for missed surveillances. One of these missed surveillances was due to operators changing from 8-hour to 12-hour shifts (see Section O8.5). A second NCV cited a deficient local leak rate test identified by an NRC information notice (see Section E8.9). Both NCVs were attributed to different causes.

In this report, five missed inservice testing surveillances resulted in a violation (see Sections M8.3, M8.4 and E8.13). The licensee attributed two of these to defective procedures. A third missed surveillance was mostly due to a scheduling process deficiency. A failure to test five control rods before Unit 2 power was increased above 40 percent was attributed to post-maintenance testing process deficiencies and human error (see Section O8.7). A missed chemistry surveillance was attributed to human error (see Section R8.1).

The licensee recently documented two PIFs where non TS required surveillances were not completed on the scheduled dates due to scheduling deficiencies. A room cooler inspection was deferred numerous times due to scheduling conflicts (PIF Q1997-3452). A computer room halon surveillance exceeded its critical date due to scheduling deficiencies (PIF Q1997-3447).

c. Conclusions

Even though most surveillances were completed within the critical date, the inspectors noted a continued adverse trend of missed surveillances. The inspectors concluded that there were multiple reasons for the missed surveillances. Some of these reasons included defective procedures and/or poor scheduling of surveillances or human error.

M3.3 Inadequate Surveillances

a. Inspection Scope (92701, 61726)

The inspectors reviewed LERs, PIFs and surveillance procedures to ensure TS-required surveillance tests were properly implemented.

b. Observations and Findings

The inspectors noted four instances of inadequate surveillances. A battery surveillance lacked the correct acceptance criteria (see Section M3.1). Additionally, a RHRSW surveillance was inadequate to assure equipment operability (see Section E8.5). A safe shutdown makeup pump surveillance was lacking design basis documentation (see Section E1.4). An operations monthly surveillance failed to include four RHRSW valves (see Section O8.6).

c. Conclusions

The inspectors concluded that some TS surveillance requirements and acceptance criteria were not adequately implemented into station surveillance procedures. The problems identified were with a small fraction of the total surveillance population, but the reviews were conducted on a sampling basis. This could indicate that further surveillance adequacy issues remain.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 50-254/96018-00, 50-265/96018-01: Misinterpreted TS Surveillance Requirement. As discussed in Inspection Report 50-254/96012; 50-265/96012, the licensee originally believed that a TS required surveillance was missed; however, upon further review, the licensee determined that no surveillances were missed. An Unusual Event was declared and terminated on September 4, 1997, and was subsequently retracted on September 17, 1997. The licensee submitted the LER voluntarily to report the event. The inspectors agreed with the licensee's determination that no TS surveillances were missed and had no further concerns. This item is closed.

M8.2 (Closed) IFI 50-254/97006-05; 50-265/97006-05: Unit 2 250 Vdc Battery Modified Performance Test Load Profile. The inspectors further reviewed the load profile and determined that the high pressure coolant injection (HPCI) suction path transfer from the contaminated condensate storage tank (CCST) to the suppression pool was adequately modeled. Also, all safe shutdown loads were included in the load profile. Additional inspections were performed on the 250 Vdc battery system and the results are documented in section M3.1 of this report. This item is closed.

M8.3 (Closed) LER 50-254/97014-00: Target Rock Safety Relief Valves (TRSRV) Did Not Receive As-found Set Point Testing Within 12 Months. The licensee identified that neither Unit 1 nor Unit 2 TRSRVs that were removed during the most recent unit refuel outages, had been set pressure tested within 12 months of their removal from the system. The licensee had since set pressure tested both TRSRVs. Both valves were outside their 1 percent acceptance band and were adjusted. The licensee evaluated the as-found condition as a condition not violating any reactor safety limits or fuel limits. The licensee attributed this event to defective procedures which failed to ensure prompt testing of the TRSRVs. Similar procedure deficiencies were identified with the main steam safety valve (MSSV) testing. The inspectors noted the licensee planned to modify TRSRV and MSSV testing procedures.

The relief valves were required by TS 4.0.E and American Society of Mechanical Engineers (ASME) Code requirements to be set pressure tested within 12 months of removal from the system. Failure to set point test the valves within the required time was a **Violation (50-254/97014-01c; 50-265/97014-01c)** of TS 4.0.E. This LER is closed.

M8.4 (Closed) LER 50-254/97016-00: Diesel Generator Cooling Water Inservice Testing Requirements not Completed. Licensee operating surveillance procedure, QCOS 6600-08, "Quarterly ½ Diesel Generator Cooling Water (DGCW) to Unit 1 and Unit 2 ECCS (Emergency Core Cooling System) Room Coolers Flow Test," was intended to be performed for both units. However, the licensee's scheduling process tested Unit 2 components, but did not schedule the test for Unit 1 components. Afterwards, the licensee completed the surveillance for Unit 1. The licensee issued two predefine work requests for the surveillance test.

This surveillance test was required by TS 4.0.E., inservice testing and inspection of ASME Code Class 1, 2, and 3 valves. The failure to complete QCOS 6600-08 for Unit 1 for the second quarter 1997 was a **Violation (50-254/97014-01d; 50-265/97014-01d)** of TS 4.0.E. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Nuclear Design Information Transmittals S040-QH-0296 AND 0302

a. Inspection Scope (71707, 37551)

The inspectors reviewed Nuclear Design Information Transmittals (NDITs) S040-QH-0296, dated February 14, 1997, and S040-QH-0302, dated March 4, 1997, to verify compliance with TS and UFSAR requirements. Nuclear Design Information Transmittal S040-QH-0296 evaluated battery loads based on abnormal operation of the Units 1 and 2 HPCI emergency oil pumps and the Unit 1 HPCI turning gear. Nuclear Design Information Transmittals S040-QH-0302 evaluated the effects on the Unit 1 safety-related 250 Vdc battery with Unit 1 at power supplying 250 Vdc busses 1, 1A, 1B, 2A, and 2B along with the Unit 2 safety-related 250 Vdc battery undergoing a service test. Each of these NDITs had Sargeant and Lundy (S&L) calculations attached to support the conclusions documented in the NDITs.

b. Observations and Findings (61726)

Calculation PMED 891377-01, Revision 10, dated March 4, 1997, identified a change to the most limiting load profile on the Unit 1 & 2 "250 Vdc Safety Related Batteries" as a main steam line break outside containment. Previously, an intermediate loss of coolant accident was considered the most limiting case. The inspectors reviewed supporting documentation within calculation PMED 891377-01 and identified the following concerns:

- The battery sizing calculations, dated February 13, 1997, that were included in NDIT S040-QH-0296 utilized 65°F. as the lowest expected electrolyte temperature. The correction factor of 1.08 for this electrolyte temperature was used in determining the number of positive plates required for the battery to meet the design load profile. However, updated TS 4.9.C, issued in the fall of 1996, identified the lowest electrolyte temperature as 60°, which required a temperature correction factor of 1.11. Therefore, by using the 1.08 factor versus 1.11, the sizing calculations were non-conservative. The use of the incorrect temperature did not reduce the battery capacity margin a significant amount, and the safety-related 250 Vdc batteries remained operable. The use of the wrong lowest expected electrolyte temperature as a design input to a battery sizing calculation was a **Violation (50-254/97014-05a; 50-265/97014-05a)** of 10 CFR 50, Appendix B, Criterion III, "Design Control."

- The worst case 250 Vdc battery load profile was based on assumptions in calculation PMED 891377-01, Revision 10. One of the assumptions used in the calculation was the failure of the unit emergency diesel generator (EDG). However, in 1993 the dc turbine emergency oil pump (EOP) was removed as a load from the safety-related 250 Vdc battery and placed on a nonsafety-related battery. Calculation PMED 891377-01 was revised to remove the dc turbine EOP from the battery load profile. However, the review and design verification of the revised calculation, and other subsequent revisions, failed to identify that with the removal of the dc turbine EOP, the failure of the ½ (swing) EDG would result in the worst case profile. The assumed failure of the ½ EDG would result in the uninterruptible power supply (UPS), a 75 amp load, being powered from the safety-related 250 Vdc battery. The failure to identify a change in a design basis assumption in 1993 due to a modification was another example of a **Violation (50-254/97014-05b; 50-265/97014-05b)** to 10 CFR 50, Appendix B, Criterion III, "Design Control."

The inspectors noted that station engineering personnel did not have a thorough understanding of the design basis of the safety-related 250 Vdc battery system. Questions regarding the load profile and the test acceptance criteria were initially posed to the engineering staff in April, shortly after the test was performed. However, complete answers were not provided to the inspectors until August. Battery sizing and load profile calculations were performed by S&L and it appeared to the inspectors that transmitted data and results required for the testing did not receive an in-depth site engineering review prior to use.

c. Conclusions

Errors in S&L calculation PMED 891377-01 were indicative of a lack of attention to detail in the design verification process of calculations. Other minor problems were identified with the calculation and the NDITs (that is; wrong calculation referenced, clarity, etc.) that also substantiate the need for management attention in engineering activities. The licensee has recently established a engineering assurance group (EAG) in April 1997. Part of the EAG's responsibilities would be to perform a sample review, as an overview function, of calculations. Due to the EAG's recent establishment, the effectiveness of the EAG could not be determined.

The inspectors considered the change to the limiting load profile of the 250 Vdc battery system to be important design basis information and expected that station engineering personnel would have detailed knowledge of the design basis.

But in addition to lack of attention to detail in the design verification process, the inspectors were concerned that station engineering personnel did not have a thorough understanding of the design basis for the safety related 250 Vdc battery system. This was evident by the initial inability to answer questions regarding the limiting load profile for the 250 Vdc battery system and the length of time to provide answers to those questions.

E1.2 Poor Communication In Backlog Reduction Efforts

a. Inspection Scope (71707)

The inspectors reviewed a list of engineering requests which had been canceled by engineering, to determine impact on other departments.

b. Observations and Findings

During the review, the inspectors learned from a supervisor in another department that an engineering request he was counting on for cathodic protection system improvements had been canceled without his knowledge. The inspectors spoke with plant management representatives who later indicated that the engineering requests had been canceled inappropriately and without proper review by Operations. Some of the engineering requests which had not been reviewed by Operations for cancellation included HPCI push button start modification work, 1A air ejector booster modification, heat tracing for diesel fire pump lines, and hot short protection valve logic modification.

The inspectors learned of another backlog reduction effort which involved engineering requests, action requests, nuclear work requests, PIFs and other items with high backlog numbers. A team was formed this period to reduce these backlog numbers with such intended methods as the screening team voting on canceling old nuclear work requests and engineering requests, and deleting nuclear work requests from the maintenance backlog when there was an engineering action associated with the request. After further management review, the licensee decided not to delete work requests from backlog numbers simply because a supporting engineering request was needed.

c. Conclusions

The inspectors found that station management was not fully aware of the nature of the backlog reduction screening efforts being attempted, and that Operations did not have sufficient understanding of the process to ensure that required items were being properly tracked and not inappropriately canceled. Poor communications between engineering, operations, and maintenance personnel was evident in both backlog reduction efforts.

E1.3 Quality of Engineering Safety Evaluations

a. Inspection Scope (37551)

The inspectors reviewed various safety evaluations and screenings associated with maintenance and surveillance activities. The inspectors also reviewed various PIFs and temporary alterations.

b. Observations and Findings

Control Rod Drive P-4

The inspectors observed Unit 2 operators perform weekly control rod surveillance tests. However, a poor electrical contact in the control rod logic circuit inhibited operators from moving control rod P-4. In order to complete the surveillance test, operators requested maintenance personnel to install a jumper around the poor electrical contact. Since late July, maintenance personnel controlled the installation and removal of the jumper with a work package and Quad Cities Instrument Procedure (QCIP) 100-13, "Maintenance Alteration Procedure." Maintenance questioned whether the practice of installing and removing the jumper weekly bypassed the more cumbersome temporary alteration process. The licensee documented the issue on a PIF Q1997-3290.

The inspectors noted this practice did not inhibit control rods from scramming but resulted in periodically blowing of a ½ amp power supply fuse. The inspectors also noted this condition was not listed on the operator work around list. However, the licensee planned to correct the deficient condition during the upcoming planned maintenance outage. In response to the PIF, operations changed QCOP 0300-01 to sequence and control installing and removing the jumper. Subsequently, operators inserted Rod P-4 and took the rod out of service to avoid the need of installing and removing the jumper from the rod control system.

The inspectors consider the addition of a jumper to the rod control system to be a change to the facility as described in the UFSAR and required 10 CFR 50.59 screening to determine if the addition of the jumper constituted an unreviewed safety question. The licensee did not perform a 50.59 screening of the addition of the jumper until the QCOP 0300-01 was changed. This licensee identified and corrected violation is being treated as a **Non-Cited Violation (50-254/97014-06; 50-265/97014-06)** consistent with Section VII.B.1 of the NRC Enforcement Policy.

Jumpering Out Alarms for Fire Diesel Pumps

The inspectors reviewed Temporary Alteration Package 97-1-27 written on August 16, 1997, to jumper out the remote alarm capability on the ½ A and ½ B diesel driven fire pumps. The inspectors identified the 10 CFR 50.59 screening criteria used to ensure an unreviewed safety question was not involved mentioned the design requirements of the remote alarms but did not adequately justify their removal. The UFSAR Section 9.5.1.2.6 indicated that standards of the National Fire Protection Association (NFPA) code were followed for fire pump installation. The NFPA code required both local and remote annunciation of low oil pressure, high jacket water temperature, failure to start and overspeed conditions. Temporary Alteration 97-1-27 failed to discuss these requirements and why the removal of the alarm functions did not constitute an unreviewed safety question. After the inspectors spoke to licensee management, engineers performed a more thorough review which indicated that an unreviewed safety question was not involved. Engineering management reviewed this event with engineering personnel.

Licensee Findings and Response

The licensee acknowledged weaknesses in adhering to the safety evaluation processes. The licensee identified a weak safety evaluation on a problem associated with the Unit 2 "C" reactor feed pump. This, and other inspector and licensee identified problems associated with the safety evaluation process, resulted in the Engineering Assurance Group documenting the process weaknesses on PIF Q1997-3530. The EAG noted some safety evaluations lacked sufficient information to become quality products. As an interim measure, engineering required a third party review of all 50.59 reviews in an attempt to improve quality. The licensee was assembling a root cause evaluation team to determine appropriate corrective actions.

c. Conclusions

The inspectors concluded engineering processes used to ensure equipment was in compliance with design requirements were not followed on some occasions. Specifically, there was no design review for adding a jumper to allow movement of Rod P-4. In addition, the partial design review for the fire diesel pump temporary alteration was inadequate. The inspectors concluded engineering and management displayed a poor understanding of design change requirements. Engineering planned third party reviews as an interim corrective action.

E1.4 Failure to Assure Design Basis Requirements of Safe Shutdown Makeup Pump System

a. Inspection Scope

The inspectors reviewed surveillance test, QCOS 2900-01, Revision 12, "Quarterly Safe Shutdown Makeup Flow Rate Test," to assure the test acceptance criteria met TS requirements and were within the design basis of the plant.

The SSMP system was designed as a backup for the reactor core isolation cooling (RCIC) system as part of 10 CFR 50, Appendix R, Section III.G, "Fire Protection and Safe Shutdown Capability."

b. Observations and Findings

Quad Cities Operational Surveillance 2900-01 acceptance criteria required the SSMP supply a minimum of 400 gpm, at a minimum pump discharge pressure of 1219.5 psig. This surveillance test was based on original S & L calculations which indicated that with 1219.5 psig at the discharge of the pump and a design flow rate of 400 gpm, the system would supply water to the reactor core at the required pressure of 1120 psig. When asked by the inspectors, the licensee could find no documentation that the tolerances of the installed instrumentation were included into the acceptance criteria for the pump discharge flow and pressure.

In late July 1996 the system engineer had generated an engineering request, Engineering Request (ER) 9604270, to address the concern that the discharge pressure of the safe shutdown makeup pump had degraded and might not be adequate, and requested a design basis calculation to reconcile instrument accuracy, sensing location, and plant conditions assumed in the design basis. In September 1996 the SSMP system was included into the TSs without resolution to ER 9604270. An adequate design basis calculation was not performed to substantiate the system test acceptance criteria by taking into consideration instrument accuracy and sensing location. Consequently, the licensee did not assure the SSMP system met the TS requirements for system operability. This was a **Violation (50-254/97014-07; 50-265/97014-07)** of 10 CFR 50, Appendix B, Criteria XI, "Test Control" and TS 4.8.J.2.

Following the inspector's identification of this issue, the licensee ran an additional surveillance test using high accuracy instrumentation. This test verified that the installed instrumentation was within the tolerance ranges of the high accuracy instruments. The licensee determined that the acceptance criteria for Unit 1 could not be assured using only the installed instrumentation. The licensee then declared the SSMP system inoperable to Unit 1, placing the unit in a 67-day limiting condition for operation (LCO), while design basis calculations were verified. The SSMP system to Unit 2 was not declared inoperable because, due to fewer line losses, the licensee had a high degree of confidence that the design basis was met.

c. Conclusions

The licensee failed to act on a system engineer's identification of the unresolved design basis issues concerning the SSMP system. Consequently, the licensee did not provide calculations and validate through testing that the TS test acceptance criteria were met for SSMP flow and pressure.

E2 Engineering Support of Facilities and Equipment

E2.1 Operable but Degraded Equipment Lists

a. Inspection Scope (37551)

The inspectors reviewed the licensee's "Open Operability Determinations Log," a Quality and Safety Assessment (QSA) audit and PIFs.

b. Observations and Findings

Due to fouling, room coolers for the Unit 2 "A" Core Spray Room and "B" Residual Heat Removal Room were classified by engineering as "operable but degraded." However, the inspectors identified that this equipment, and other degraded safety-related equipment were not included in the "Open Operability Determinations Log" maintained by operations. This included installation of jumpers to remove the alarm functions for both fire diesel pumps, leakage past the seat for the Unit 2 3B power operated relief valve, a potential condition for the Unit 2 emergency core cooling system suction strainers to be made of improper material, and others. The inspectors spoke to licensee management of these concerns. The licensee identified that two separate lists of operable, but degraded equipment existed, but were not consistent.

The QSA group audited both lists maintained by engineering and operations and identified the following:

- three issues on the engineering list were not evaluated for operability concerns
- seven items on the engineering list which had been reviewed via the PIF process had not been evaluated via the operability determination procedure
- four items on the operations list were not on the engineering list
- eight issues on the operations list needed to be resolved prior to startup from the upcoming planned maintenance outage (Q2P01). Only two of the eight items were included in the scope of Q2P01.

In Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions," the NRC issued guidance on how degraded or nonconforming conditions should be resolved commensurate with the safety significance of the issue. The inspectors noted in some instances above, the licensee had not fully evaluated the nature of the degraded condition, and what action would be needed to resolve the condition in a time commensurate with the safety significance.

c. Conclusions

Lists of important equipment considered operable but degraded were not scrutinized well by either engineering or operations. In some cases, there were no plans on when or how to remove equipment from a degraded status. The inspectors concluded the licensee displayed a lack of rigor in ensuring important equipment would be brought back into compliance with design requirements within a timely manner.

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
M1.2	8.3.2.1	250 Volt Station Battery
O8.3	2.4.4, 9.2.5	Ultimate Heat Sink

For the sections reviewed, the inspectors did not identify any discrepancies between plant configuration and design basis as described in the UFSAR.

E7 Quality Assurance in Engineering Activities

E7.1 Review of 50.54(f) Performance Indicator Accounting

a. Inspection Scope (40500)

By letter dated January 27, 1997, the NRC required the licensee to provide additional information pursuant to 50.54(f) for plans to measure performance improvement at each ComEd nuclear site. In a response dated March 28, 1997, ComEd committed to track each nuclear station's performance using standard industry indicators on a monthly basis. The inspectors reviewed three performance indicators reported by the licensee to corporate. The inspectors reviewed how the licensee complied with the counting guideline provided by corporate in the desktop instruction manual for three performance indicators. These performance indicators included temporary alterations, engineering requests (ERs), and ERs overdue.

b. Observations and Findings

The inspectors determined the temporary alterations counted at the station and reported to corporate were different. However, the instruction manual allowed for not counting the following as temporary alterations: ventilation dampers wired open, installation of furmanite clamps, or installation of recorders. After reconciling the reported list with the instructions, the inspectors believed the number of temporary alterations reported offsite were accurate.

The inspectors determined the method for counting ERs and ERs overdue was not in compliance with the desktop instruction manual. Specifically, ERs counted at the site and reported to corporate did not include parts evaluations and requests for design changes. Similarly, the station only counted 2 of the 19 types of ERs for the ER overdue count. The instruction manual required all Priority A and B ERs, regardless of ER type, be counted.

The licensee acknowledged the weakness and admitted the counting process was still not consistent between sites. The various sites met to develop a more standardized method of reporting the ER numbers.

Section E1.2 of this report documents problems identified by the inspectors where ER backlog reduction efforts were not well reviewed, understood or communicated throughout the station.

c. Conclusions

The inspectors concluded some temporary alterations at the site were not included in the count of performance indicators. However, the temporary alteration indicator was in compliance with the instructions. The inspectors determined ERs and ERs overdue were not counted in compliance with the instructions. The inspectors noted the licensee was attempting to reconcile differences in their counting methodologies to ensure that all sites were counting the performance indicators consistently. This would allow a better comparison of performance between ComEd sites. The inspectors noted that some efforts to reduce the ER backlog were not reviewed or understood throughout the station.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Unresolved Item (URI) 50-254/92201-02; 50-265/92201-02: This URI had four concerns. Concern 2 was no assessment of the effect of higher flows on Unit 1 and Unit ½ DGCW pumps and was closed in Inspection Report No. 50-254/92025(DRP); 50-265/92025. Concern 3 was the ½ DGCW pump had not demonstrated meeting the demands of the ½ DG Heat Exchanger (HX) and the Unit 1 Emergency Core Cooling System (ECCS) pump room coolers; and was closed in Inspection Report No.50-245/95004(DRP); 50-265/95004(DRP).

Concern 4 was an operability question with the Unit 2 DGCW due to unsuccessful flow balancing in that most distributions to the individual Unit 2 ECCS room coolers were unknown. The licensee installed flow instrumentation for each of the Unit 2 ECCS room coolers by Design Change Package (DCP) 95-60. The DCP was declared operable on May 29, 1997. The flows were continuously observable and appropriately trended against conservative criteria. Concern 4 is closed.

Concern 1 was the Unit 1 DGCW flow was unbalanced and distributions to individual Unit 1 ECCS room coolers were unknown. The differential pressure (D/P) across each Unit 1 ECCS room cooler was well trended by QCOS 5750-9 except during a 7 month period due to an improper engineering turnover (This was considered a Deviation in Inspection Report No.50-254/96010(DRP); 50-265/96010(DRP)). If adverse D/P was detected, the licensee was required to document the condition on a PIF. The licensee would then measure flow with a Controlotron Ultrasonic Flowmeter. Any adverse flow detected required an evaluation and the room cooler cleaned if necessary. The licensee was planning on revising QCOS 5750-9 to measure Controlotron flow monthly for all Unit 1 ECCS room coolers. Some scaffolding had been installed to facilitate Controlotron measurements. Significant portions of DCP 95-57 had been written to install permanent flow instrumentation for the Unit 1 ECCS room coolers and was scheduled for implementation during the Unit 1 Refueling Outage Q1R15 in September of 1998. Concern 1 is closed. This URI is closed.

E8.2 (Closed) IFI 50-254/93003-01; 50-265/93003-01: The ½ Diesel Generator Cooling Water Pump Transfer Starter Panel 2251-10-0 Components Were Not In Preventative Maintenance Program. The inspectors verified the licensee wrote and tracked a preventive maintenance item (PM ID 104293) for components on DGCW pump starter panel 2251-10-0. The electrical maintenance predefine coordinator ensured the item was performed on a 3-year frequency as prescribed by Quad Cities Electrical Maintenance Surveillance (QCEMS) 0250-06, "Exhaust Fan and Room Cooler Motor Environmental Qualification Surveillance," Revision 7. The panel was specifically delineated in Attachment F of the procedure. This item is closed.

E8.3 (Closed) LER 50-254/94002-00: "B" Control Room Emergency Ventilation (CREV) failure. This LER documented the inoperablity of the "B" CREV system due to the failure of a compressor motor contactor on January 4, 1994. The failure of the contactor was attributed to cumulative cycling. One cause of the cycling of the contactor was a result of the compressor being sized such that it will handle the heat load under extreme conditions. Under normal operating conditions, the compressor frequently cycles as opposed to running continuously with its load being modulated. A previous cause of cycling the contactor was the control of cooling water to the condenser which frequently caused trips/restarts of the compressor resulting in additional cycles of the contactor.

Corrective actions in response to the event included contactor replacement and changes to operating procedures to better control cooling water flow to the condenser. Planned corrective actions documented in the LER included the installation of a hot gas bypass system for the compressor to reduce cycling by inducing a larger heat load on the compressor to better match its capacity. In the cover letter transmitting the LER to the NRC, dated January 29, 1994, the licensee committed to the NRC to install the "B" CREV hot gas bypass system. In August 1997 the inspectors reviewed the LER, spoke with engineering staff and determined that the system had not been installed and that design work on the modification had essentially been stopped. The failure to accomplish this action was a **Deviation (50-254/97014-08)**. This LER is closed.

E8.4 (Closed) URI 50-254/94004-17; 50-265/94004-17: Inoperable Heat Trace Line from Unit 1 Standby Liquid Control (SBLC) Tank to One of the Pumps. The NRC's Diagnostic Evaluation Team (DET) identified this condition in September 1993. By November 1993 the licensee had replaced the entire heat tracing system for the SBLC systems for both units. The replacement systems were improved and have had greater reliability. The minimum low temperature alarm setpoints for both the piping and tanks were increased from 78 to 83° F. The inspectors verified during a walkdown that the new system was in good material condition with the new controllers indicating 95 °F. which was their nominal setpoint. This item is closed.

E8.5 (Closed) URI 50-254/94028-02; 50-265/94028-02: Inadequate Residual Heat Removal Service Water (RHRSW) Surveillance. The inspectors observed that surveillance testing for the RHRSW room cubicle cooler did not contain limits for acceptable differential pressure across the cooler. The licensee revised the procedure and established criteria but concluded that differential pressure measurements alone could not establish operability of the cooler. The licensee relied on periodic cleaning of the coolers and differential pressure measurements to assess operability. If differential pressure criteria were not met, engineers measured flow with a portable ultrasonic flowmeter since no flow gauges were installed. Similarly, other required ECCS room coolers did not have installed flow gauges. The NRC issued a violation in Inspection Report No.50-54/97006(DRP); 50-265/97006(DRP) since appropriate corrective action was not taken in a timely manner to measure flow through the core spray room coolers after differential pressure measurements exceeded the surveillance procedure acceptance criteria. This item is closed.

E8.6 (Closed) IFI 50-254/95005-03; 50-265/95005-03: Long Term Use of Temporary Sealant Repair. The inspectors verified that a permanent repair to the leaking 2A recirculation pump flange was completed during refueling outage Q2R14. This item is closed.

E8.7 (Closed) IFI 50-254/96002-12; 50-265/96002-12: The UFSAR Needed to be Updated to Reflect the Frequency of a Full Core Off-load and Previous Licensing Commitments. The licensee revised procedures and updated the UFSAR. All issues were addressed in the most recent UFSAR revision annotated Revision 3, December 1995 except for the clarification concerning storage of other than GE 8x8R fuel. On February 19, 1997, a new nuclear tracking system (NTS) item was opened by the licensee to track this issue. On September 9, 1997, the licensee closed this NTS item. All General Electric fuel critically analyzes use of one of two methods described in UFSAR section 9.1.2.3. For the ATRIUM-9B Siemens fuel the licensee will use an analysis as submitted to the Quad Cities Regulatory Assurance staff on April 23, 1997, for incorporation into the UFSAR. This item is closed.

E8.8 (Closed) IFI 50-254/96002-13; 50-265/96002-13: Problems With Safety-related Control Room Emergency Ventilation (CREV) System. Early in 1996 the inspectors noted numerous equipment problems with the CREV system leading to high unavailability of the system. The licensee determined the high system unavailability was due to poor work planning and scheduling, several design deficiencies, and a lack of a preventative maintenance program. Subsequent to Inspection Report No. 50-254/96002(DRP); 50-265/96002(DRP), in Inspection Report No. 50-254/96017(DRP); 50-265/96017(DRP), the inspectors documented more design and testing deficiencies with the system. The NRC issued two Severity Level IV violations after conducting an enforcement conference with the licensee. The licensee completed work to restore the system to its original design basis. The inspectors noted a decreased number of equipment problems since these efforts were completed. This followup item is closed.

E8.9 (Closed) LER 50-254/96008-00: TS Pressure not Achieved During a Local Leak Rate Test (LLRT). In response to NRC Information Notice 96-13, "Potential Containment Leak Paths Through Hydrogen Analyzers," the licensee identified the containment atmospheric monitoring inlet piping was not pressurized to 48 pounds per square inch as required by TS 4.7.A. The licensee determined the cause of the event to be a deficient procedure. The licensee corrected the procedure.

The inspectors determined this was a non-cited violation (50-254/96008-15; 50-265/96008-15). The inspectors reviewed the licensees corrective actions. This LER is closed.

E8.10 (Closed) Violation 50-265/96010-01: Incorrect Replacement Torus Suction Valve Weight Used in Safety Evaluation Review. In July 1996 NRC inspectors were concerned that the licensee's design review process had failed to identify the consultant's use of the incorrect valve weight even though no major hazard had been caused. The licensee conducted an investigation to determine the root cause and any other related conditions. In response to the violation the licensee stated that: (1) even though the documentation from the consultant indicated to the licensee that the new weight had not been properly taken into consideration, it had been by the actual analysis methodology; (2) some of the licensee staff had been made aware by phone that the correct weight was taken into consideration but no documentation of the phone call's discussion could be found; (3) the design review requirements of Nuclear Engineering Procedure (NEP) 12-03, "Nuclear Design Information Transmittals (NDITs)," Revision 0, will be more assiduously enforced in the future; and (4) an engineering department training session to reemphasize the NDIT design review requirements of NEP 12-03 was held during the departmental meeting on October 1, 1996. The inspectors reviewed the licensee's followup investigation, and immediate and long-term corrective actions and found them to be thorough and adequate. This violation is closed.

E8.11 (Open) IFI 50-254/96011-06; 50-265/96011-06: Evaluation of Pipe Whip Impingement Plate Alteration. While resolving improperly installed concrete expansion anchors (CEAs), the licensee identified a questionable mounting support for high energy line break impingement plate 2-JIHP-3. The inspectors reviewed Calculation No. 5061-00-EP-B2, Revision 4, which evaluated this support configuration. After noting that a safety factor of 2.0 was used to qualify the existing CEAs, the inspectors asked the licensee why the standard safety factor of 4.0 was not used. This was subsequently provided in Calculation No. QDC-0000-S-0210, Revision 0. After reviewing this information and discussing it in detail with the licensee, the NRC disagreed with the licensee's technical arguments justifying their use of the safety factor of 2.0.

The NRC determined that additional analyses and/or anchor bolt capacity upgrades would be required for high energy pipe whip restraints, in order to meet the CEA manufacturers' recommended capacities. The NRC staff considered the criteria for CEAs given in NRC Bulletin 79-02 and in Revision 2 of the Generic Implementation Procedure developed by the Seismic Qualification Utility Group for Unresolved Safety Issue A-46 to be acceptable. Pending a review of the licensee's schedule to complete the additional analyses or upgrade the anchorage capacity, this item will remain open.

E8.12 (Closed) LER 50-254/96022-00: "B" CREV System Unable to Maintain 1/8" D/P. The inspectors verified work was completed to restore the system to its design basis as described in the UFSAR. Testing conducted on April 22, 1997, verified the system could maintain 1/8" D/P in the control room emergency zone. The inspectors verified that the licensee submitted to the NRC a revised control room habitability study as committed to in the corrective actions described in the LER. This LER is closed.

E8.13 (Closed) LER 50-254/97003-00: Missed Visual Examination of High Pressure Coolant Injection Check Valve. On April 29, 1997, the licensee identified a failure to visually examine the Unit 1 2301-45 check valve. As required by the ASME Code for Class 1, 2, and 3 components, the licensee was required to perform a visual examination following replacement of the valve. The licensee declared the system inoperable until a qualified inspector examined the valve in accordance with code requirements. The licensee attributed the missed visual examination to inadequate procedures.

TS 4.0.E required inservice inspection and testing of ASME Code Class 1, 2, and 3 components after replacement. Failure to perform the required ASME Code visual inspection constitutes a **Violation (50-254/97014-01e; 50-265-97014-01e)** of TS 4.0.E. This LER is closed.

IV. Plant Support

R8 Miscellaneous Radiation Protection and Chemistry Issues

R8.1 (Closed) LER 50-265/97010-00: Missed Chemistry Surveillance. With the Unit 2 "B" offgas hydrogen analyzer inoperable, TS Table 3.2.H-1 required a grab sample of an 8-hour frequency. On August 19, 1997, chemistry technicians missed taking an 8-hour grab sample from the Unit 2 offgas system. This event was due to a human error. The licensee counseled the individual. The failure to take the TS required grab sample from the offgas system was considered a **Violation (50-254/97014-01f; 50-265/97014-01f)** of TS 3.2.H. This LER is closed.

F1 Control of Fire Protection Activities

The inspectors reviewed several activities related to fire protection and safe shutdown components, and the related operational maintenance, and engineering activities involved with supporting these components. Problems with inoperable fire pumps, inoperable safe shutdown paths, inoperable sprinkler systems, poor tracking of actions needed to track degraded components, and poor engineering reviews all led to an overall weak performance in fire protection activities. Some response to safe shutdown problems discovered by the licensee were considered good.

F1.1 Problems Associated with the "A" Fire Diesel Pump

a. Inspection Scope

The inspectors observed maintenance, testing and troubleshooting activities associated with the ½ A diesel fire pump.

b. Observations and Findings

After performing annual maintenance to the ½ A fire diesel pump, the licensee tested the pump in accordance with QCMMS 4100-32, "½ A Diesel Driven Fire Pump Annual Capacity Test." Having been informed by an insurance representative that alarm testing for the diesel driven fire pumps was inadequate at Quad Cities because initiation of the alarm at the sensor was not performed, the licensee corrected the procedure to include initiation at the sensor (for low oil pressure and high jacket water temperature). When testing the alarms with initiation at the sensor, it was discovered that the alarm circuitry caused the ½ A diesel to trip on overspeed. A review of the troubleshooting and repair efforts is discussed below. A near miss personnel safety issue occurred during the testing and is documented in section M1.3.

Troubleshooting Efforts

Troubleshooting activities were initially poor. Some of the problems included:

- A troubleshooting plan which was expected by the maintenance superintendent, was not used. A root cause evaluation process was not used for several days of the activity.

- The inspectors noted that maintenance history indicated a number of similar failures on both the ½ A and ½ B fire pumps since 1993. The root cause for these failures had not been determined in many cases, and trending of the problem was not readily available. Maintenance rule evaluations were not adequate to justify that the failures were not to be considered maintenance rule functional failures. Resolution of this aspect is being reviewed in the maintenance rule inspection (see Inspection Report No. 50-254/97017(DRP); 50-265/97017(DRP)).

- When initial troubleshooting led technicians to replace the electronic governor (speed switch), the switch was not adjusted properly during installation. This caused the diesel engine to overcrank during subsequent testing.

- Continuity of the repair technicians assigned to the fire pump repair effort was not maintained throughout the troubleshooting process.

- The vendor representative brought in to assist in troubleshooting was not certified by the vendor to be qualified for the fire pump diesel engine.

Troubleshooting activities continued for several days and resulted in the fire pump exceeding the 7-day administrative LCO time limit. The licensee documented this condition on a PIF (97-3214).

After 3 days, the license put together a team and a comprehensive troubleshooting plan to evaluate the root cause of the engine tripping. Possible failure modes were systematically eliminated. The licensee determined that the cause of the problem was poor installation of a design modification in 1993 which replaced the mechanical governor with an electronic governor. During installation, wires carrying relatively large alarm bell currents were routed near wiring transmitting the sensitive electronic governor speed signal. The inductive current related to the clearing of the alarm circuit had apparently caused the nearby unshielded speed sensor circuit to sense overspeed conditions, causing an overspeed trip. The licensee corrected the tripping problem by jumpering out the associated alarms.

The inspectors found that the licensee performed a poor review of the design basis justification for jumpering the alarms (Section E1.3), and Operations did not properly address operator action required for conditions when the diesel fire pump alarms were inoperable. Operations had included actions for operators to attend the fire pumps during weekly surveillance operation, but had failed to adequately address actions needed during emergency fire pump operation and during some auto start conditions. Following discussions with Operations management, the inspectors verified that the licensee addressed these concerns with updated surveillance (QCOS 4100 series) and operating (QCOP 4100 series) procedures .

c. Conclusion

The inspectors found that poor initial troubleshooting efforts and other maintenance problems such as improper governor installation delayed the completion of fire pump work within the administrative LCO time limits. Later troubleshooting resulted in discovery of a long standing problem with the fire pump. Justification for jumpering out fire pump alarms was poor, and operator compensatory actions were not adequately spelled out.

F1.2 Safe Shutdown Paths Inoperable

a. Inspection Scope

The inspectors reviewed licensee actions upon discovery that 9 of 16 safe shutdown paths were inoperable.

b. Observations and Findings

On August 26, 1997, the licensee discovered that procedures written to support taking the units to cold shutdown conditions in the event of a fire did not support the requirements of the fire protection report. This condition rendered 9 of 16 safe shutdown paths inoperable because tripping of non-safe shutdown path loads would not have been accomplished. The licensee estimated that the instantaneous fire risk associated with having nine safe shutdown paths and ½ A pump inoperable during dual unit operation would have been approximately 2.7E-03 per reactor year. The licensee took quick action to correct the procedure discrepancies, began an investigation of the cause of the discrepancies, and reported the condition on LER 50-254/97021. Previous procedure problems had been identified in earlier LER reviews, and will be looked at as part of the review of this LER. Review of this item will be accomplished following the licensee's review, and tracked as part of followup to the LER.

c. Conclusions

The inspectors noted that the already relatively high risk associated with fires at Quad Cities was made even higher by procedure discrepancies in 9 of 16 safe shutdown paths. Licensee action upon discovery was good, but previous corrective actions for other LERs and subsequent corrective actions must still be evaluated.

F1.3 Poor Corrective Action for Fire Protection Problems

a. Inspection Scope

The inspectors observed licensee corrective action for several fire protection issues, including management meetings, action plans for equipment repair, and observation of compensatory actions in place.

b. Observations and Findings

The inspectors found operators and management to be insensitive to inoperable fire-related protection equipment problems. Some of this insensitivity appeared to be in part to a history of equipment exceeding administrative LCO times at Quad Cities.

Fire Pump Degradation Corrective Action

Since June 27, 1994, fire impairment FM-94-152 had been inoperable due to hydraulic concerns with the wet pipe suppression system in the Unit 1 heater bay. This system has a 14-day limiting condition for operation action statement which was controlled administratively (fire protection requirements were removed from Quad Cities TS). On January 13, 1995, fire impairment FM94-152 was transferred to FM-95-23. Two other impairments were added on January 13, 1995, due to hydraulic concerns with wet pipe systems in the Unit 2 heater bay and Unit 1 Southeast Residual Heat Removal corner room. Although the LCO time was 14 days, these impairments were in effect for over 3 years in some cases without resolution, using fire watches as compensatory actions. Quad Cities Administrative Procedure (QCAP) 1500-1 "Administrative Requirements for Fire Protection," only required a non-reportable PIF to be generated when the 14 day LCO time limit was exceeded.

The hydraulic concerns were due to degraded performance of the stations' two diesel driven fire pumps. The licensee had informed the inspectors on several previous occasions that a modification was planned and approved to correct these problems with degraded fire pump performance and to correct problems with zebra mussel blockage of the fire pump suctions. (Modification number DCP 9600045 was approved for work on September 24, 1996.) The inspectors were informed during this inspection period that the approved modification had been put on hold due to funding concerns. Although knowing about the funding concerns since June 1997, the licensee had no plans in place for improving fire pump performance and/or correcting the hydraulic impairments. The inspectors also found that during the recent ½ A and B fire pump testing, additional degradation of fire pump flow was noted. In total, a degradation of about 6 percent was noted since the fire pumps were rebuilt in the 1993 time frame. While this only exacerbated the original hydraulic impairment problems and did not cause any additional systems to be inoperable, it did point to the continuing need for effective corrective action for fire pump problems.

Poor Heater Bay Sprinkler Corrective Actions

On September 8 the inspectors questioned the unit supervisor for Unit 1 about a log entry regarding an inoperable sprinkler in the Unit 1 heater bay. The unit supervisor informed the inspectors that on September 6 a sprinkler head in the heater bay wet pipe system began flooding the heater bay, requiring operators to isolate the entire wet pipe system for half of the heater bay. When asked about compensatory actions for the isolation of the wet pipe system, the unit supervisor indicated that the system was the same system already in a long term impairment (since June 1994) and no additional corrective action other than the fire watches for the original impairment were required.

The inspectors were concerned because the original impairment required fire watches due to a degraded flow condition (about 5 gpm degradation from required flow.) The problem resolution on September 6 caused the suppression system to have zero flow. No effective plan for short term maintenance corrective action had been identified until after September 10 following inspectors discussions of the problem with senior station management. The original plan developed then focused on waiting until hydrogen injection was scheduled to be turned off on September 17 (for dose minimization concerns), or 12 days into the period of the isolated wet pipe system. The inspectors asked station management why the priority was so low that either hydrogen injection could not be turned down earlier or reactor power could not be reduced to minimize dose and complete the work earlier. In the discussion, inspectors pointed out that hydrogen injection was being turned off daily on Unit 2 due to equipment problems. Eventually the licensee corrected the problem on about September 15, after reducing reactor power to repair another component.

During the time the wet pipe was isolated, the inspectors observed the fire watches in place as compensatory measure. The inspectors noticed on September 9 that cameras in place for fire watches to monitor were not functioning, and had been noted as needing repairs for several days. The inspectors notified the operations manager, who later called for an investigation. The licensee found that several cameras were not providing the picture adequately for the required fire watches, and documented this on PIFs Q1997-03450, 03437, and 03445. The conditions were corrected and fire watches were briefed on the proper cameras to watch and what to do in the event of inoperable cameras. Quad Cities Administrative Procedure 1500-01, Revision 6 dated February 17, 1997, Step D.2.c.2.(b) required a roving (15 minute) fire watch be established if a water suppression system which protects a safe shutdown system is inoperable and the affected unit is not in a safe shutdown condition. Since the cameras which were supporting the hourly fire watch rounds were not fully operable, the NRC and licensee considered this a case of missed fire watch rounds, a violation of station procedures and is a **Violation (50-254/97014-09; 50-265/97014-09)** of TS 6.8A. Generation of a PIF was the only requirement in the QCAP 1500-1 procedure for a missed fire watch and for most missed fire protection LCOs. The PIF process appeared to be a weak vehicle to focus station attention on risk important equipment and processes. The PIFs reviewed by the inspectors were given the lowest level in significance and did not generate a higher level review, even when LCOs were missed by long periods or when multiple systems were inoperable.

The inspectors found that, in general, fire protection issues received relatively low priority at Quad Cities, even when exceeding LCO times were involved. Even significant fire protection LCOs (such as loss of water to the heater bay suppression system) did not receive any significant plan of the day attention or management discussion during meetings observed by the inspectors, compared to balance of plant equipment which affected generation capability (such as gland seal level control valves.)

c. Conclusion

The inspectors noted an overall lack of sensitivity to fire protection issues. A number of equipment problems resulted in administrative LCO time limits being exceeded. Some equipment was inoperable in excess of 3 years, with planned modifications to repair the problems recently canceled or changed. This led station personnel to be less than aggressive in addressing new fire protection problems. Fire watches were the required compensatory actions for some of these impairments. The inspectors noted a lack of rigor in assuring the required fire watches were met, and a violation was cited. Problem identification forms were not effective in focusing management attention on the fire protection problems. This all occurred in an environment where the licensee was aware of a relatively high fire risk at the station.

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 September 19, 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

W. Pearce, Site Vice President
R. Fairbank, Engineering Manager
F. Famulari, Quality and Safety Assessment
C. Norton, Operations Supervisor
C. Peterson, Regulatory Affairs Manager
G. Powell, Radiation Protection Supervisor
M. Wayland, Maintenance Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92701:	Followup - Planned Non-Routine Activities
IP 92902:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/97014-01a; 50-265/97014-01a 50-254/97014-01b; 50-265/97014-01b 50-254/97014-01c; 50-265/97014-01c 50-254/97014-01d; 50-265/97014-01d 50-254/97014-01e; 50-265/97014-01e 50-254/97014-01f; 50-265/97014-01f	VIO	surveillance requirements not met during reactor modes
50-265/97014-02	VIO	failure to follow procedure QCMM 1515-07
50-254/97014-03; 50-265/97014-03	NCV	discrepancy in QOM check list
50-254/97014-04; 50-265/97014-04	VIO	errors in QCTS 0240-06 resulted in performance test not being performed per TS 4.9.5
50-254/97014-05a; 50-265/97014-05a 50-254/97014-05b; 50-265/97014-05b	VIO	design basis information not correctly translated
50-254/97014-06; 50-265/97014-06	NCV	50.59 screening of the addition of the jumper not performed until QCOP 0300-01 was changed
50-254/97014-07; 50-265/97014-07	VIO	no demonstration that SSMP would perform in accordance with requirements of TS 4.8.J.2
50-254/97014-08	DEV	hot gas bypass system not installed
50-254/97014-09; 50-265/97014-09	VIO	poor heater bay sprinkler corrective actions

Closed

50-254/94010-00	LER	unplanned scram of control rod during surveillance
50-254/94010-01	LER	unplanned scram of control rod during surveillance
50-254/96001-00	LER	the "B" CRVS inoperable due to inoperable relay
50-254/96002-03; 50-265/96002-03	IFI	buildup of debris on trash rack resulted in low water level inside intake structure
50-254/96006-00	LER	the TS 3.0.A incorrectly invoked

50-254/97001-00	LER	missed operations surveillances
50-254/97008-00	LER	inadequate operations surveillance
50-265/97008-00	LER	missed control rod surveillance
50-265/97009-00	LER	control room operators misread abnormal offgas radiation readings
50-254/96018-00	LER	misinterpreted TS surveillance requirement
50-254/96018-01	LER	misinterpreted TS surveillance requirement
50-254/97006-05; 50-265/97006-05	IFI	The HPCI suction path transfer from the CCST to the suppression pool and any cycling of HPCI on and off considered in the load profile and modified performance test of the Unit 2 250 Vdc battery
50-254/97014-00	LER	the TRSRV did not receive as-found set point testing within 12 months
50-254/97016-00	LER	diesel generator cooling water inservice testing requirements not completed
50-254/92201-02; 50-265/92201-02	URI	no assessment of effect of higher flows on Unit 1 and Unit ½ DGCW pumps
50-254/93003-01; 50-265/93003-01	IFI	the ½ DGCWP transfer starter panel 2251-10-0 components were not in preventative maintenance program
50-254/94002-00	LER	this LER documented the inoperability of the "B" CREV system due to the failure of a compressor motor contractor on January 4, 1994
50-254/94004-17; 50-265/94004-17	URI	inoperable heat trace line from Unit 1 SBLC tank to one of the pumps
50-254/94028-02; 50-265/94028-02	URI	inadequate RHRSW surveillance
50-254/95005-03; 50-265-95005-03	IFI	long term use of temporary sealant repair
50-254/96002-12; 50-265/96002-12	IFI	the UFSAR needed to be updated to reflect the frequency of a full core off-load and previous licensing commitments
50-254/96002-13; 50-265/96002-13	IFI	problems with safety-related CREV system
50-254/96008-00	LER	Technical Specification pressure not achieved during a LLRT
50-265/96010-01	VIO	incorrect replacement torus suction valve weight used in safety evaluation review
50-254/96022-00	LER	the "B" CREV system unable to maintain 1/8" D/P
50-254/97003-00	LER	missed visual examination of HPCI check valve
50-265/97010-00	LER	missed chemistry surveillance
50-254/97014-03; 50-265/97014-03	NCV	discrepancy in the QOM check list
50-254/97014-06; 50-265/97014-06	NCV	50.59 screening of the addition of the jumper not performed until QCOP 0300-01 was changed

<u>Discussed</u>

50-254/96011-06; 50-265/96011-06	IFI	evaluation of pipe whip impingement plate alteration

LIST OF ACRONYMS AND INITIALISMS USED

ALARA	As Low As Reasonably Achievable
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
CCST	Contaminated Condensate Storage Tank
CEA	Concrete Expansion Anchors
CFR	Code of Federal Regulations
ComEd	Commonwealth Edison Company
CRD	Control Rod Drive
CREV	Control Room Emergency Ventilation
dc	direct current
DCP	Design Change Package
DET	Diagnostic Evaluation Team
DEV	Deviation
DGCW	Diesel Generator Cooling Water
D/P	Differential Pressure
EAG	Engineering Assurance Group
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ELMS	Electrical Load Monitoring System
ENS	Emergency Notification System
EOP	Emergency Oil Pump
ER	Engineering Request
GL	Generic Letter
GSC	Gland Steam Condenser
HPCI	High Pressure Coolant Injection System
HX	Heat Exchanger
IDNS	Illinois Department of Nuclear Safety
IEEE	Institute of Electronics of Electrical Engineers
IFI	Inspector Followup Item
IST	Inservice Test
kV	Kilovolt
LCO	Limiting Condition for Operation
LCV	Level Control Valve
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LPCI	Low Pressure Coolant Injection
MSSV	Main Steam Safety Valve
NCV	Non-cited Violation
NDIT	Nuclear Design Information Transmittal
NEP	Nuclear Engineering Procedure
NFPA	National Fire Protection Association
NTS	Nuclear Tracking System
OWA	Operator Workarounds
P&ID	Piping and Instrument Diagrams
PDR	Public Document Room
PIF	Problem Identification Form
QCAP	Quad Cities Administrative Procedure
QCEMS	Quad Cities Electrical Maintenance Surveillance

QCEPM	Quad Cities Electrical Preventive Maintenance
QCGP	Quad Cities General Procedure
QCIP	Quad Cities Instrument Procedure
QCMM	Quad Cities Mechanical Maintenance
QCMMS	Quad Cities Mechanical Maintenance Surveillance
QCOA	Quad Cities Operating Abnormal Procedure
QCOP	Quad Cities Operating Procedure
QCOS	Quad Cities Operating Surveillance Procedure
QCTS	Quad Cities Technical Staff Procedure
QGA	Quad Cities General Abnormal Procedure
QOM	Quad Cities Operations Manual
QSA	Quality and Safety Assessment
RCIC	Reactor Core Isolation Cooling System
RG	Regulatory Guide
RHR	Residual Heat Removal
RHRSW	Residual heat Removal Service Water
S&L	Sargent and Lundy
SBLC	Standby Liquid Control
SSMP	Safe Shutdown Makeup Pump
SSPV	Scram Solenoid Pilot Valve
TRSRV	Target Rock Safety Relief Valve
TS	Technical Specification
TSUP	Technical Specification Upgrade Program
UFSAR	Updated Final Safety Analysis Report
UPS	Uninterruptible Power Supply
URI	Unresolved Item
Vdc	Volt direct current
WR	Work Requests