U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No:	50-254/96020(DRP), 50-265/96020(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:	December 7, 1996 - January 27, 1997
Inspectors:	C. Miller, Senior Resident Inspector K. Walton, Resident Inspector L. Collins, Resident Inspector R. Ganser, Illinois Department of Nuclear Safety
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EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/96020(DRP), 50-265/96020(DRP)

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

Operations

- Control room modifications were well planned and controlled (Section O2.1).

- Some decline in control room operator performance was noted. During the inspection period, operators mispositioned a control rod during control rod exercising and misaligned one train of the standby gas treatment system rendering it inoperable. These human performance errors were violations of station procedures and Technical Specifications (TS) (Section O4.1).

- Management oversight was not adequate to ensure consistent quality operability evaluations for important systems (Section O7.1).

Surveillance

- The inspectors identified that the control room emergency ventilation system was not adequately tested in accordance with the TS surveillance requirement. This was a missed surveillance test and a TS violation (Section M1.1).

- Poor planning resulted in an inadequate review of TS requirements prior to changing surveillance procedures to accommodate a new shift rotation. Failure to adequately perform the review resulted in a surveillance interval being exceeded (Section O3.1).

- The inspectors observed some operator knowledge and procedural weaknesses during performance of a control room emergency ventilation system surveillance (Section M1.2).

Maintenance

- Efforts to improve maintenance and testing of standby liquid relief valves produced some positive results. The licensee improved craftsman knowledge and skill level and made efforts to provide input to the overall training process for mechanical maintenance. However, the inspectors observed limited supervisory oversight during this work activity which was a repeat observation (Section M1.3).

- Material condition deficiencies continued to burden the station. Emergent work affected the planned work schedule and increased radiation dose for plant workers (Section M2.1).

Engineering

- The inspectors identified weaknesses in the licensee's operability evaluation of the shared emergency diesel generator (EDG) start failure and problems with the methodology for determining diesel generator reliability data (Section E1.1).

- The inspectors concluded that an initial operability assessment for the safe shutdown makeup system was weak, because the assessment failed to verify the ability to take manual actions (Section E1.2).

- Identification of a design discrepancies in the emergency core cooling system (ECCS) suction strainers was good. Also, training provided to the operators on potential ECCS pump cavitation was timely and effective. The inspectors identified potential problems with credit taken by the licensee for containment over pressure in the associated safety evaluation, since values used were not included in the licensing basis (Section E2.2).

Plant Support

- The inspectors identified the flow switch and pressure indicator for the service water effluent radiation monitor did not have a scheduled calibration frequency (Section R2.1).

Report Details

Summary of Plant Status

Unit 1 operated at or near full power during most of the inspection period. Minor power reductions were conducted to perform routine activities such as turbine weekly tests, control rod maneuvers, backwash of condensate demineralizers, and scram time testing. A larger power reduction occurred in late December due to pump suction relief valve leakage on the 1C reactor feedwater pump. The valve was repaired and the unit was returned to full power the following day.

Unit 2 operated at or near full power during most of the inspection period. The unit operated at about 660 MWe for several days late in the inspection period to repair a leaking feedwater heater vent line.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

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

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

December 13	A notification was made due to a control room ventilation surveillance test not being performed properly.
December 23	A notification was made regarding emergency core cooling system (ECCS) suction strainers differential pressure found to not be in accordance with design requirements.

[1]Topical headings such as O1, M8, etc., are used in acco dance with the NRC standardized reactor inspection report outline. Individual reports are not expected to addi ess all outline topics.

January 27	A notification was made that the emergency notification system (ENS) and commercial communications were lost due to a tripped circuit breaker.
January 27	A notification was made regarding the identification of drywell piping design inadequacies related to Generic Letter (GL) 96-06.

O2 Operational Status of Facilities and Equipment

O2.1 Control Room Modifications

a. Inspection Scope (71707)

The inspectors reviewed the licensee's installation of a control room modification designed to improve information display and readability for operators and supervisors, and to provide other control room improvements.

b. Observations and Findings

The inspectors reviewed plans for the installation, and noted that the licensee had planned the change well. The modification was first installed in the simulator, which allowed the operators to train on accident scenarios under the new configuration. Improvements were made in the control room in three phases in order to minimize disturbances. In one instance inspectors noted increased noise levels resulting from the work during a surveillance activity. Shift management stopped the work until the surveillance activities were complete. The inspectors noted that under the new configuration, Quad Cities general abnormal procedures (QGA) flowcharts for accident scenarios would be placed over the sequence of event monitors. The inspectors discussed the apparent discrepancy with operations supervisors and the licensee agreed to further evaluate the effect this would have on operators in accident scenarios. In general, the inspectors noted that the improvements were beneficial to the operators in terms of improved horizontal workspace, procedure and drawing storage, information presentation, supervisor oversight capability, and personnel traffic control.

c. Conclusions

The inspectors noted the control room modifications were an overall benefit to the operators, and the installation of the modification was well planned and controlled.

O3 Operations Procedures and Documentation

O3.1 Technical Specification Surveillances Not Performed Within Required Time Period

a. Inspection Scope (71707)

The inspectors reviewed a licensee identified problem regarding Technical Specification (TS) surveillance intervals being exceeded.

b. Observations and Findings

The nuclear station operators (NSOs) and equipment operators (EOs) switched from an 8-hour to a 12-hour shift rotation on January 6. Both the NSOs and EOs performed surveillances that were required shiftly, which was defined by TS as once every 12 hours. Several days into the new rotation, the licensee noted a potential problem with meeting the surveillance interval if operators did not perform the surveillances immediately after shift change.

Since the surveillance procedures did not require the operators to document the time the surveillance readings were taken, the licensee had difficulty establishing whether or not the surveillance interval had been exceeded. A poll of operators on shift during the four days in question found at least one situation where approximately 18 hours between surveillances occurred. Based on this one instance and the uncertainty surrounding the other days, the licensee planned to submit a licensee event report (LER) documenting the failure to perform the surveillances within the required time period.

After discovery, the licensee changed the governing procedures to require the surveillances to be performed within the first three hours of the shift and to document completion times.

The licensee determined that shiftly channel check surveillance requirements required by TS 4.2 pertaining to reactor pressure and water level exceeded the surveillance interval by more than the 25 percent extension allowed by TS 4.0.B.

The inspectors concluded that a violation of TSs occurred. However,, this licensee identified and corrected violation is being treated as a **Non-Cited Violation (50-254/265-96020-01)**, consistent with Section VII.B.1 of the Enforcement Policy.

c. Conclusions

The licensee failed to adequately perform a review of all TS requirements prior to changing to the new shift rotation and surveillance procedures.

O4 Operator Knowledge and Performance

O4.1 Declining Operator Performance

a. Inspection Scope (71707)

The inspectors reviewed recent control room operator errors which resulted in one train of a safety system being made inoperable for approximately , hours and a control rod mispositioning event. The inspectors reviewed procedures and spoke with control room operators.

b. Observations and Findings

Upon initial entry into the control room approximately 2 hours after turnover, a Unit 2 NSO questioned why the annunciator "Standby Gas Treatment Trouble" was lit. Subsequently, the control switch for the "B" train of standby gas treatment was found in the "off" position. Since the train would not automatically start with the control switch in off, the train was inoperable. In addition, both units were in a 7-day limiting condition for operation (LCO) as required by TS 3.7.P.1. The control switch was returned to its "primary" position, restoring operability, and an investigation was initiated.

One month later, during control rod exercising in accordance with Quad Cities Operating Surveillance (QCOS) 0300-01, "CRD [control rod drive] Exercise," a NSO inadvertently used the "rod out notch override" switch instead of the "single notch withdraw" button. As a result, the control rod being tested was withdrawn one notch further than anticipated. Subsequently, the rod was inserted to the correct position and a problem identification form (PIF) was initiated to document the error and the licensee's investigation.

The inspectors reviewed the licensee's investigation into the two events and identified three examples of failure to properly implement station procedures:

(1) On December 16, 1997, the standby gas treatment (SBGT) system Train B control switch was put in the off position at 2139 during the performance of QCOP 7500-2, "Standby Gas Treatment System Shutdown." An NSO failed to perform steps G.3.A.6 and G.3.A.7 of QCOP 7500-2, which would have placed the Train B control switch to "primary" and failed to verify that all the SBGT system annunciators were cleared. This is an example of a **Violation (50-254/265-96020-02a)**.

(2) On December 16, 1996, the Unit 2 reactor building ventilation isolation function was being tested, and the Unit 2 operators were performing QCOP 7500-2. However, Unit 1 operators were generally assigned responsibility for the common panels which included the reactor building ventilation system and SBGT system controls. Operating Department Memo 96-2 directed the Unit 1 NSO to walk down the common panels once per hour. Since the condition of the SBGT

system was not discovered for approximately 4 hours, these required checks were not adequately performed.

Additionally, this condition existed through shift turnover. The oncoming shift of NSOs were required to walk down the control room panels in accordance with Quad Cities Administrative Procedure (QCAP) 0210-4, "Shift Turnover Panel Check for Common Panels," Section D.3.d. The procedural requirement was checked complete by the Unit 1 oncoming NSO indicating that SBGT Train B was in "primary" and Train A was in "standby"; however, Train B was actually in the "off" position. The oncoming Unit 1 operators logged the annunciator as being lit in the Unit 1 log book, but did not understand the cause of the alarm or recognize that the train was inoperable. This is another example of a **Violation (50-254/265-96020-02b)**.

(3) On January 18, 1997, the NSO performing CRD exercising failed to properly implement step 4 of QCOS 0300-1, when the "rod out notch override" switch was used instead of the "single notch withdraw" button while exercising a control rod. Step 4 of QCOS 0300-1 required when exercising control rods that were not fully withdrawn, i.e., position 48, that the operator use the "single notch withdraw" button instead of the "rod out notch override" switch. The control rod was to be inserted to position 24 and withdrawn back to position 26, but instead was withdrawn to position 28. This is another example of a **Violation (50-254/265-96020-02c)**.

The licensee considered the causes of these events to be poor procedure adherence, lack of a questioning attitude, and insufficient degree of attention applied. Corrective actions included counseling the individuals involved and a review with all operating crews of operating standards and expectations.

The lack of attention to detail appeared to be more than an isolated case since three separate operators responsible for checking the status of the SBGT system failed to note the inoperable Train B. Additionally, corrective actions for the event were not sufficient to prevent a similar operator error (involving one of the same individuals) approximately 1 month later when the control rod was mispositioned.

The operations department performance trending program identified an increased human error rate for control room operators during the month of December. A PIF was initiated to further investigate the declining performance trend.

c. Conclusions

This series of operator errors indicated a lack of attention to plant configuration. The inspectors noted that control room operator performance was relatively good over the past year, but these events marked a declining trend in the area of control room operator performance.

O7 Quality Assurance in Operations

O7.1 Problematic Operability Evaluations

a. Inspection Scope (71707)

The inspectors reviewed several issues which involved operability evaluations for degraded equipment or which involved return to service of equipment which had been in a TS limiting condition for operation (LCO) for degraded conditions.

b. Observations and Findings

The inspectors' review indicated that, in some cases, operations and station management were not ensuring quality root cause evaluations and compensatory actions were being performed prior to declaring equipment operable. Three examples are discussed below:

(1) In one instance documented in Section E1 of this report, the shared emergency diesel generator (EDG) was declared operable before a complete root cause analysis (all possible failures) had been reviewed, before root cause and corrective action for the suspected component failures had been identified and implemented, before a schedule had been established for analysis of the suspected component failure to ensure the accuracy of the initial root cause effort, or before the need for increased testing frequency or component change-out requirements had been established.

The inspectors noted the need for a hurried effort and limited review could have been a factor since the EDG was in a 7-day LCO which would have required both units to shut down. However, since the shared EDG was the component with the single largest effect on core damage frequency, and diesel generator failures had been problematic in the past, the inspectors considered the lack of station management and operations management oversight of the shared EDG operability call a weakness.

(2) In another instance documented in Section E1.2 of this report, operations management considered degraded safe shutdown makeup system valves operable because the valves could be manually operated. However, when the inspectors questioned the ability of the operators to operate the valves under design accident conditions, the licensee identified that additional equipment would be required to provide a mechanical advantage.

(3) In a third instance, operator action to secure service building ventilation was credited in order to consider control room ventilation operable under certain accident conditions. As documented in Section M1.2 of this report, the inspectors identified that operators were not trained on how to secure service building ventilation and were unable to perform the task without further guidance during a surveillance test.

c. Conclusions

The inspectors concluded that management oversight was not always adequate to ensure consistent quality operability evaluations were being performed and validated for key systems.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Violation (50-254/265-95004-01): Control Rod Hydraulic Control Unit (HCU) Returned to Service After Maintenance Without Being Tested. Operations allowed maintenance workers to adjust valve packing on an HCU without scram time testing the HCU after work was completed. The licensee subsequently scram time tested the control rod successfully. The licensee discussed this event with operations and maintenance personnel and revised two work control administrative procedures to ensure post-maintenance test requirements were reviewed by operations personnel. The inspectors reviewed the licensee's corrective actions. This item is closed.

O8.2 (Closed) LER (50-254/95004): Unit 1 High Pressure Coolant Injection (HPCI) Failed to Operate. Subsequent troubleshooting revealed the motor speed changer (MSC) gear train failed. The licensee determined an improper setting of a contact block resulted in excessive plunger travel required to actuate the switch contacts. The licensee replaced the limit switch and MSC gear train and later tested the system satisfactorily. The licensee changed the vendor manual to reflect recommendations for installation and adjustment of the limit switches. The licensee continued to test the HPCI systems at an increased frequency in an attempt to identify problems sooner and improve HPCI performance. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Improper Testing of Control Room Emergency Ventilation System (CREVS)

a. Inspection Scope (62703)

The inspectors reviewed station surveillance procedures to ensure Section 4.8.D of the TS requirements was incorporated. The inspector spoke to engineering personnel about deficiencies identified and reviewed electrical prints associated with CREVS. The inspectors also reviewed Section 6.4 of the updated final safety analysis report (UFSAR).

b. Observations and Findings

As a result of the inspectors' questions, a system engineer identified that the surveillance test did not properly test the automatic isolation function of CREVS as required by TS 4.8.D.5.b.2. Specifically, QCOS 1600-13, "Refueling Outage PCI

Groups 2 and 3 Isolation Test," verified the operation of control room annunciator B-8, "Control Room Vent Isolated." However, the annunciator was energized from a relay different from the relays which closed the control room ventilation dampers. The licensee declared the system inoperable, notified the NRC, and documented this concern on PIF 96-3499.

Engineering successfully tested the proper relays in accordance with an interim procedure and the system was later declared operable. The licensee planned to incorporate the interim procedure into QCOS 1600-13. Also, the licensee planned to review portions of the recently upgraded TSs to ensure testing adequately addressed TS requirements.

Failure to properly test the automatic isolation function of CREVS is a **Violation (50-254/265-96020-03)** of TS 4.8.D.5.b.2.

c. Conclusions

This problem, and another example documented in Inspection Report 50-254/265-96017 were identified by NRC inspectors. As a result of problems recently identified with the design and testing of CREVS, several opportunities were available to the licensee to self-identify these discrepancies.

M1.2 Surveillance Observations

a. Inspection Scope (62703)

The inspectors observed portions of the following surveillance tests:

QCOS 5750-2	Control Room Emergency Filtration System Test
QCOS 1300-1	Reactor Core Isolation Cooling (RCIC) Pump Operability Test
QCOS 2300-5	Quarterly High Pressure Coolant Injection (HPCI) Pump Operability Test

The inspectors attended pre-job briefings, accompanied operators during the surveillances, and reviewed the TSs and UFSAR system descriptions.

b. Observations and Findings

i. CREVS Operability Test (QCOS 5750-2)

The inspectors attended the briefing for the monthly CREVS surveillance and noted that neither the NSO or the EO involved with the test were familiar with newly added procedure steps to secure service building ventilation. The inspectors were concerned that the new requirement to secure service building ventilation, which was not only required during the surveillance, but also during a loss of cooling accident (LOCA), had not been communicated to the operators. Securing service building ventilation was an important step to ensure that control room positive pressure was maintained and to minimize in-leakage to the control room emergency zone during an accident. Failure to perform these actions in a timely manner during an accident could increase the dose to operators.

The NSO involved in the test activity questioned the unit supervisor and shift engineer about the new procedural requirement. (The unit supervisor and shift supervisor were aware of the new steps and of some existing guidance on how to complete the step.) The procedure was in the revision process to add specific instructions to secure service building ventilation. Prior to actual test performance, the operators made a procedure field change (PFC) to the affected procedure to add the detailed steps for securing service building ventilation.

As noted above, the surveillance procedure was in the revision process at the time the surveillance was scheduled to be performed. At the end of the inspection period, the procedure had been revised, but all the operators had not yet been trained on the new requirements.

The CREV system included a refrigeration condensing unit (RCU) which provided cooling to the entire control room emergency zone and operated based on control room return air temperature. The RCU itself could be cooled by either plant service water (non-safety related) or "safety related" residual heat removal service water (RHRSW). The UFSAR stated that plant service water was the normal supply and that on loss of plant service water the condenser could be cooled by RHRSW. The inspectors noted that for the design basis LOCA analysis, offsite power was assumed to be unavailable; therefore, plant service water would be unavailable. The surveillance procedure called for flushing the RCU with RHRSW but provided the option to either run the test with RHRSW or plant service water.

During the observed surveillance, operators chose to run the test with plant service water and indicated to the inspectors that the test was normally run that way. The inspectors asked the cognizant system engineer if the surveillance test was ever run with the equipment cooled by RHRSW. The test had been operated with RHRSW three times in the last 2 years, with the longest interval between runs of 14 months. Technical Specification 4.8.D.1 required operators to verify once every 18 months that the RCU was capable of removing the required heat load. Test procedure QCOS 5750-2 was inadequate in that it allowed the test performers to select at random which service water system to use. Failure to incorporate adequate guidance into the test procedure is another example of Violation 50-254/265-96017-06, of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." That violation was recently issued in Inspection Report 50-254;265-96017, dated February 4, 1997. At the close of this inspection period, the licensee had not yet responded to the initial violation and was revising applicable test procedures to ensure that the RCU was tested every 18 months with both RHRSW and plant service water. The inspectors will review the licensee's response to the initial violation and no additional information regarding this example is required.

ii. Unit 2 RCIC Pump Operability Test (QCOS 1300-1)

During the performance of QCOS 1300-1, the inspectors observed that the equipment operator (EO) was knowledgeable and provided good on-the-job training to two trainees. In addition, the inspectors noted that the radiation protection briefing and coverage during the potentially high dose job to be thorough and effective with respect to the ALARA [as low as reasonably achievable] program.

The inspectors noted that both Unit 1 and Unit 2 RCIC rooms had scaffolding that had been in place for several months. The system engineer indicated the scaffolding had been erected to support valve operation test and evaluation system (VOTES) testing of valves. However, the testing had not occurred and was not scheduled. The system engineer told the inspectors that the scaffolding was built to seismic standards and was periodically checked. The inspectors did not find any deficiencies with the scaffolds, but noted that it was a housekeeping issue that could hinder operator performance.

iii. Unit 1 HPCI Operability Test (QCOS 2300-5)

The inspectors attended the shift briefing and observed the performance of the test from the control room. The test had been scheduled for the afternoon shift and coincided with ongoing control room modification work. The inspectors noted that the control room was crowded and noisy due to the modification work. The shift engineer cleared the control room of all construction personnel throughout the duration of the HPCI surveillance. The inspectors considered this action appropriate since the HPCI surveillance required full operator attention and communication and the construction work could have been distracting.

Operator performance during the surveillance was good. Communications were clear and the operators demonstrated good knowledge of the HPCI system and the surveillance procedure. All TS requirements were met.

c. Conclusions

The inspectors noted some knowledge and procedural weaknesses during the performance of the CREV system surveillance. Operator knowledge of the new requirement to shut down service building ventilation during CREV system operation was weak due to the failure of the operations department to promptly update the procedure and train the operators on the current system status. Operators performance with respect to procedure adherence and communications during the surveillances observed was good.

The inspectors concluded that the CREV system surveillance procedure did not adequately control the testing configuration of the RCU to ensure that the system would always be tested in accordance with TS 4.8.D.1. Failure to provide adequate test instructions, was another example of an earlier violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control."

M1.3 Observation of Standby Liquid Control System Relief Valve Rebuild

a. Inspection Scope (62703)

The inspectors observed mechanical maintenance department (MMD) personnel overhaul and bench test the standby liquid control (SBLC) system relief valves. The inspectors also interviewed the SBLC system engineer to assess overall system performance.

b. Observations and Findings

The licensee planned to remove and bench test the SBLC relief valves at each refuel outage. The relief valves had historically experienced inconsistent lift-set pressure test results. The inconsistencies were thought to have been caused by the lack of precise test controls and weak work practices during valve overhaul. The licensee's response was to change the method of overhaul and testing for these valves. The licensee brought a vendor representative onsite who gave instructions to coach and assist MMD craftsmen on the correct overhaul and bench testing techniques. The vendor provided input to upgrade the station procedures and current technical information for MMD training.

The licensee had previously identified that the station procedure for this task was obsolete and no longer met the station standards. The vendor provided a current work instruction and expertise to guide the work activity.

The inspectors noted that MMD supervisors monitored the work activity infrequently. Numerous work activities in progress limited the supervisor's ability to devote time and attention to any single job. This weakness did not manifest itself in any identifiable problems with this particular work activity. However, as documented in Inspection Report 50-254;265-96014, dated December 20, 1996, Section M1.1.b.ii, the lack of supervisory oversight was previously observed for maintenance on important equipment.

The inspectors observed lift-set pressure testing on one of the valves, and verified the calibration of the test gauge was current. The test procedure required two consecutive tests within specifications. The consistency of the successive tests was good. Of the six SBLC system relief valves designated for overhaul and lift-set testing, two of the valves were rejected. On one valve, the bonnet could not be machined sufficiently to house the larger spring assembly which was to be installed in all of the rebuilt valves. This valve, and one other exhibited problems with insufficient clearance between the disc assembly and the internal orifice. The licensee generated a PIF to address the cause of the wrong clearances. Spare parts for the remaining valves were correct. Four valves were successfully overhauled, lift-set pressure tested and placed into storage for future installation. The MMD developed a tracking method to keep accurate updated maintenance records of each valve.

c. Conclusions

The licensee's effort to improve maintenance and testing of SBLC relief valves produced positive results as evidenced by consistent test results. The licensee improved craftsman knowledge and skill level for this job and made efforts to provide input to the overall training process for mechanical maintenance. However, limited supervisor oversight was an observed weakness, which was a repeat observation.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Continued High Number of Material Condition Deficiencies

a. Inspection Scope (40500)

The inspectors reviewed some of the material condition issues which affected station performance.

b. Observations and Findings

- The shared (1/2) EDG experienced a failure to stop and a failure to start. The stop failure was attributed to a failed governor solenoid and the failure to start was an air start motor problem. Both failed components were repeat problems with the EDG system (Section E1.1).

- The safe shutdown makeup (SSM) motor-operated valves were found to have undersized motors (Section E1.2).

- The 1A reactor feed pump (RFP) was out of service for the entire inspection period awaiting rotating element and seal replacement.

- The 2C RFP was returned to service following seal replacement.

- The 2A control rod drive (CRD) pump developed a seal leak. The pump remained in service for limited use only.

- The 2A and 1B containment atmospheric monitoring (CAM) systems were inoperable at different times which required entry into 30-day shutdown LCOs. The 1B CAM system remained out-of-service (OOS) at the end of the inspection period.

- The 2B stator water cooling pump failed to produce the required flow during testing and was determined to have high motor vibes. The low flow condition was later attributed to a discharge check valve problem, and additional operator action was required to use the 2B pump.

- Unit 1 reactor water cleanup (RWCU) system problems, including demineralizer bypass valve leakage and 1A RWCU pump problems resulted in RWCU system being shut down for several days. Reactor water chlorides increased to an administrative limit for action but did not reach any TS limits.

- The 1B RHRSW pump developed an outboard seal leak. The pump was scheduled for repair in February 1997.

- Hydrogen pumps supplying both units tripped off several times. On several occasions hydrogen addition to the reactor was reduced to conserve the hydrogen supply.

- The 1A .urbine building closed cooling water heat exchanger was inspected and found to be severely degraded. At the end of the inspection period, tube replacement was in progress.

- Unit 2 dropped load due to 2C1 feedwater heater operating vent line leak. A section of piping was replaced.

c. <u>Conclusions</u>

The inspectors noted that a high number of material condition deficiencies continued to burden the station. Emergent work adversely affected the maintenance schedule and contributed to increased dose for plant workers.

M8 Miscellaneous Maintenance Issues

M8.1 <u>(Closed) LER (50-265-95001 and Rev. 1):</u> Valve Seat Leakage Exceeded Local Leak Rate Test (LLRT) Limits. During the Unit 2 refueling outage, the licensee identified nine valves which had exceeded their LLRT leak rate limits. The licensee machined the interior of two leaky outboard main steam isolation valves and replaced the seat liner. The remaining valves were repaired or replaced and retested satisfactorily. The inspectors reviewed the post-maintenance LLRT results. This item is closed.

M8.2 <u>(Closed) Violation (50-254/265-95005-01):</u> Maintenance Personnel Failed to Adhere to Procedural Requirements. Workers, attempting to remove a CRD, failed to lock the carriage and winch cart together. This resulted in the control rod drive and the cart being damaged. Workers failed to complete a work activity screening sheet prior to working on the Unit 2 HPCI system as required by the procedure. Maintenance personnel were instructed on the use of work activity screening sheets when working on nuclear safety related equipment. Maintenance personnel were also briefed on department training requirements to ensure personnel possessed the knowledge and skill required to perform as signed tasks. The licensee changed CRD handling procedures and trained maintenance personnel on CRD handling equipment. The inspectors attended a hands-on training session and viewed a subsequent CRD installation. This item is closed.

M8.3 <u>(Closed) Inspector Follow-up Item (50-254/265-95009-01):</u> Shared EDG Failed to Start Due to Failed Relay. The shared EDG started and ran for about 15 seconds during a surveillance test before stopping. Monitoring equipment identified a failed Time Delay (TD)-1 relay. Subsequent analysis of the failed relay determined the relay had a manufacturing defect which was not detected during bench testing prior to installation. The licensee revised Quad Cities Electrical Preventive Maintenance (QCEPM) procedure 0700-18, "Calibration of Diesel Generator Time Delay Relays," to check TD relays for full needle travel prior to installation into the circuits. The licensee sent a notification to owners of this style of EDG to make those owners aware of the relay failure. The inspectors reviewed the licensees corrective actions. This item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 <u>Problems With Shared EDG</u>

a. <u>Inspection Scope (71707)</u>

The inspectors spoke to licensee personnel and observed maintenance activities associated with the shared emergency diesel generator. The inspectors reviewed the licensee's root cause evaluations and subsequent corrective actions.

b. <u>Observations and Findings</u>

b.1 <u>Shared EDG Failed to Stop</u>

Operations declared the shared EDG inoperable after the EDG failed to stop at the conclusion of routine testing. An engineering investigative team developed a plan to determine the causes for the EDG not stopping on command. The team produced a root cause evaluation, that determined three likely causes for the failure to shut down. Engineering determined the most probable cause was a binding shutdown solenoid in the governor and replaced the solenoid. During the subsequent operability test, the shared EDG failed to start.

b.2 <u>Poor Root Cause Followup for the Shared Emergency Diesel Generator Failure to Start</u>

After repairing the shutdown solenoid, the shared EDG failed to start during a post-maintenance operability test. Engineering reassembled the investigative team and started a second root cause analysis. Engineering deduced that a component in the air start system caused the failure to start, based on system engineer observations of the diesel during the attempted start and further component inspection and testing. Maintenance tested and inspected components in the air start system. The licensee identified one of the two air start motors was difficult to turn by hand, replaced both air start motors, and intended to send the faulted air start motor out for further analysis. The licensee also inspected air start motors for both unit EDGs and found the motors turned satisfactorily.

In the interim, engineering determined that the problem was corrected, and operations declared the EDG operable on January 18. However, the inspectors identified that the air start motors still had not been sent for analysis by January 22 and questioned plant management about the confidence of the operability call since the primary component believed to be at fault had not yet been evaluated. In addition, other potential failure modes for the conditions noted had not been evaluated. The inspectors noted for both EDG failures, the licensee had identified a "likely" component failure and replaced it, but had not identified the root cause for the failures of the components. The inspector's review of records back to 1992 revealed that the shutdown solenoid or the air start motors had been the cause of EDG failures on at least five occasions. Yet, the licensee's followup actions for these events did not reference a plan to correct the root cause or address component replacement frequency or increased surveillance frequency.

The licensee referenced a proposed modification to replace the governor shutdown solenoids, but could not specify an implementation date when asked by the inspectors. The licensee agreed that a higher priority should have been placed on air start motor testing and sent the motors off site for evaluation on January 22. Engineers also documented further reasoning to support the validity of the initial operability call.

b.3 <u>Poor Component Trending</u>

The inspectors noted that the system engineers did not classify the failure of the shared EDG to start as a valid test failure. The reason given was that during the surveillance test, one half of the starting air tanks were valved out to satisfy in-service testing requirements. Since the EDG started on the second try fifteen minutes later (and so theoretically would have started with both air banks valved in on the second try), the engineers concluded that the start should not be counted as a "valid" test failure. The inspectors noted that this action could precondition the EDG for the purposes of reliability testing, since the air start, governor, and fuel systems had been exercised on the first start attempt. Licensee engineers informed the inspectors that the station followed, but was not committed to the requirements of Regulatory Guide (RG) 1.9, Revision 3, "SELECTION, DESIGN, QUALIFICATION AND TESTING OF EMERGENCY DIESEL GENERATOR UNITS USED AS CLASS 1E ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS," for determining reliability of the EDG.

The inspectors determined that the licensees's conclusion that the failed EDG start was not a "valid failure" was inconsistent with the guidance contained in RG 1.9 in three areas.

1) Section 2.1 under "start failure definitions" stated: "Any condition identified in the course of maintenance inspections (with the emergency diesel generator in the standby mode) that would have definitely resulted in a start failure if a demand had occurred should be counted as a valid start failure."

   The failure mode identified by the licensee during maintenance troubleshooting <u>did</u> result in a start failure.

2) Section 2.1 under "exceptions" stated: "Unsuccessful attempts to start or load-run should not be counted as valid demands of failures when they can be definitely attributed to the following: ... A failure to start because a portion of the starting system was disabled for test purposes if followed by a successful start with the starting system."

   System engineers referred to this as the reason the start failure was not valid. However, the inspectors noted that the licensee's investigation pointed out that the alignment of the air start system with only one set of air banks was not the reason for the failure to start since air pressure in the tanks did not go below normal required pressure.

3) Section 2.1 also stated: "the successful test that is performed to declare the emergency diesel generator operable should be counted as a demand."

   The inspectors noted that the test which identified the EDG would not start was performed for such purposes. The test was a valid demand, the failure mode was not due to the test configuration, and the failure mode resulted in a failure to start. Therefore, the inspectors concluded that the licensee was not following the intent of RG 1.9.

In general, the licensee was counting surveillance testing of the EDGs as valid start successes if the surveillance passed, but not as valid start failures if the surveillance did not pass on the first try. This did not appear to be a valid statistical approach to determine EDG reliability. The inspectors noted that information on EDG reliability was provided to the NRC in past meetings (e.g., management meeting in RIII 12/11/95) as a basis for safety system reliability. Resolution of the reliability testing and start failure root cause and corrective action is an **Inspector Followup Item (50-254/265-96020-04)**, pending the inspectors review of the licensee's assessment of this issue.

c. <u>Conclusions</u>

The inspectors determined the licensee's root cause evaluation approach for the problems with the shared EDG had improved somewhat from similar EDG root cause efforts in 1995, but still did not arrive at resolution of root cause and effective followup action in a time commensurate with the safety significance of the system. In addition, the inspectors identified that reliability testing statistics for the EDGs might be flawed and did not appear to be in accordance with RG 1.9.

E1.2 Weak Operability Evaluation for the Degraded Safe Shutdown Makeup (SSM) System Valves

a. Inspection Scope (71707)

The inspectors reviewed the operability assessment, corrective action documents, and caution cards for the SSM system. The inspectors also spoke with the system engineer, operators, valve engineers and the shift operations supervisor about the system operation.

b. Observations and Findings

While conducting a plant tour, the inspectors noted that caution cards attached to SSM valve control switches stated that the valve motor operators were undersized, and that the valves might not close under all conditions. The SSM system provided water from a storage tank to the reactor during certain Appendix R fire scenarios if the feedwater and RCIC systems were unavailable. The motor driven pump injected water to either the Unit 1 or Unit 2 reactor. Although the system was not credited in any accident analyses described in Chapter 15 of the UFSAR, it was included in the station's individual plant examination and was an important system in terms of overall risk.

The inspectors reviewed the licensee's corrective action document and spoke with the cognizant system engineer. The licensee identified that the original valve data used for motor sizing was incorrect and undersized motors were installed for three SSM valves. A recent calculation showed a required torque of 106 ft-lbs [foot-pounds] to close the valves under design condition, while the motor operators were sized to produce 42 ft-lbs. The affected valves were the two SSM discharge valves (one to each unit) and the SSM recirculation valve. System operating procedures required the recirculation valve to initially be opened and closed after the injection valve to the proper unit was opened.

The operability evaluation determined that the system was operable but degraded. The evaluation took credit for local, manual operation of the valves. As compensatory measures, the licensee placed caution cards on the controls, submitted a procedure change request to include the caution in the procedures, and verified the ability to cycle the valves under static conditions. Engineering performed a safety evaluation screening and planned to evaluate long term corrective actions.

The inspectors questioned the validity of the static test for manually operating the valves, since the torque required under static conditions was different from that required under the design basis fire scenario. Subsequently, the licensee simulated a test and identified that the valves would be difficult to close without an additional mechanical advantage. Valve wrenches were then staged in the SSM room.

The operability evaluation did not consider the time constraints on operators during fire to place the SSM system in service. The Quad Cities Appendix R analysis concluded that the SSM system must be injecting into the reactor within 35 minutes after reactor shutdown. The procedures specified local operation but were quite complex, and the inspectors questioned whether there was sufficient time to obtain a valve wrench to manually close the recirculation valve. The inspectors noted that in the current condition with the valve wrenches staged locally, the time to initiate the system had not increased relative to the initiation time with fully qualified valve operators.

The inspectors noted that this SSM problem was added to the operator work around list. However, the inspectors identified that a lead unit planner, responsible for prioritizing and planing work, was not aware of the most recent problem with the SSM. In addition, no action request (AR) or engineering request (ER) was written to resolve the degraded condition.

The operability assessment process required corrective actions be tracked by the station's nuclear tracking system (NTS). The licensee issued an NTS item to develop a long term corrective action plan by March 1, 1997. In addition, the licensee performed a 50.59 screening evaluation since the system was to remain in a degraded condition for an extended period of time.

Several weeks after the inspector initially questioned the licensee about the degraded condition of the valves, an operating crew wrote ARs for the three valves. The work planning group prioritized the work as emergent work to be worked within 5 weeks. The inspectors noted that the AR process had been bypassed and that the degraded equipment was not tracked in either engineering or maintenance backlogs. The licensee planned to review the various processes for initiating ARs, ERs, and the general PIF procedure to improve the process. Pending the inspectors' review of the licensee's assessment of needed improvements in this area, this is an **Inspector Followup Item (50-254/265-96020-05).**

c. Conclusions

The licensee's approach to the condition of the valves was not consistent with the importance of the system. Poor assumptions in the initial operability assessment, and failure to appropriately apply the proper administrative procedures to resolve known deficiencies showed a lack of sensitivity to significant operator workarounds.

E2 Engineering Support of Facilities and Equipment

E2.1 Facility Adherence to the UFSAR

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

IR Section	UFSAR Section	Applicability
E2.2	6.2 and 6.3	ECCS Suction Strainer Design
R2.1	11.5.2.7	Process Liquid Radiation Monitors
E1.2	5.4.6.5	SSM System
M1.2	6.4	CREV System

E2.2 Design Discrepancy with Emergency Core Cooling System (ECCS) Suction Strainers

a. Inspection Scope (92700)

The inspectors attended plant onsite review committee meetings and spoke with design engineering personnel and operators concerning ECCS suction strainers. The inspectors reviewed the licensee's operability evaluation, 10 CFR 50.59 safety evaluation, supporting calculations, and Sections 6.2 and 6.3 of the UFSAR.

b. Observations and Findings

Licensee's Evaluations

On December 20 a contract engineering firm, reviewing an upcoming modification to replace the ECCS suction strainers, identified that the ECCS suction strainers were not built in accordance with design as described in the UFSAR. Specifically, the UFSAR assumed a maximum of 1-foot differential pressure (d/p) across the strainer at 10,000 gallons per minute (gpm) (rated) flow. However, the analytical model of the installed suction strainer had a 5.8 foot d/p at rated flow. The higher d/p could affect the net positive suction head (NPSH) of ECCS equipment in post-accident conditions.

Section 6.2.2.3 of the UFSAR assumed one of the four suction strainers would be fully plugged during a large break loss of coolant accident (LOCA). During the LOCA, all low pressure injection pumps (about 30,000 gpm injection) would draw suction through the remaining three strainers. The difference in the head loss of the installed versus designed strainer was documented on PIF 96-3571. Engineering performed short term and long term calculations to determine the NPSH required for post-accident operation of various combinations of core spray (CS) and residual heat removal (RHR) pumps. The licensee took credit for post-accident primary containment over pressure in the calculations. The use of over pressure was described in UFSAR, Section 6.3.3.2.9, and in an NRC safety evaluation report (SER) dated August 25, 1971.

The short term calculation used 5.5-pounds per square inch gauge (psig) over pressure and concluded there would be adequate NPSH for CS and RHR pumps operating at full flow for the first 8 minutes post-accident. After 8 minutes, when primary containment pressure started decreasing, the margin to pump cavitation would be decreased. The CS pumps were more vulnerable to cavitation. However, the licensee believed the design flow rate of 4500-gpm would still be met with the CS pumps cavitating, and that no damage would occur as a result of operating the CS pumps with some cavitation.

The long term calculation took credit for 3.4 psig over pressure and operator action to throttle back on CS and RHR injection flows. This resulted in CS and RHR pumps not cavitating and able to deliver the design post-accident flow rates. Engineering stated these flow rates were sufficient for the required safety function.

Operations declared the system "operable, but degraded," pending further engineering reviews. Prior to taking the shift, operators received training on the indications of ECCS pump cavitation. Training consisted of observing a simulator scenario and review of QCOP 1000-30, "Post Accident RHR Operations" and Quad Cities Operating Abnormal (QCOA) 1400-01, "CS System Automatic Initiation." These procedures were changed to throttle ECCS injection flow to assure adequate core cooling. The inspectors reviewed the procedure changes and spoke to operators after training was provided and concluded that the operators sufficiently understood the indications of pump cavitation and actions to be performed.

Inspectors' Review of Licensee's Evaluations

The inspectors noted that the NRC allowed the licensee to use "a few psi [pounds per square inch]" over pressure as stated in a safety evaluation report dated August 25, 1971. However, no quantitative values were provided. The values of over pressure used by the licensee were from a vendor calculation and were based on an NRC approved methodology. This information, although not documented in the UFSAR, was design information available to the licensee. The inspectors questioned the limits on the over pressure amount used in the 50.59 evaluation, since specific values were not included in the UFSAR. This is considered an **Inspector Followup Item (50-254/265-96020-06)** pending further NRC review during the next report period.

c. Conclusions

Self identification of the discrepancy between the design and actual condition of the suction strainer was good. In addition, the training provided to control room operators on ECCS cavitation was timely and effective. Further NRC inspection of the specific values of over pressure assumed in the licensees 50.59 evaluation were planned.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Inspector Followup Item 50-254/265-95006-01 and LER 50-265-95005: Unit 2 Reactor Scram During Electro-Hydraulic Control (EHC) System Testing. During EHC system testing, the licensee failed the "A" pressure regulator expecting the "B" pressure regulator to properly take control. The licensee determined the root cause as the failure to recognize the severity of the transient produced by the pressure regulator failure test. As a result of a larger than expected difference between the pressure regulator settings, and an improperly set steam line resonance compensator (SLRC), Unit 2 automatically shut down. The licensee determined the method used to set the SLRC was incorrect. The licensee implemented a procedure to properly set the SLRC. Similarly, the EHC pressure amplifier circuit procedure was modified to ensure the pressure setpoint bias was set to 3-psid. The inspectors reviewed the procedure changes and observed portions of EHC testing. The inspectors noted that changes made to the EHC testing process were successfully incorporated into Unit 1 EHC testing. This item is closed.

E8.3 (Closed) Inspector Followup Item (50-254/265-95009-03) and LER (50-254/95008 and Rev. 1): Oscillations of Unit 2 High Pressure Coolant Injection (HPCI) Pump. During routine testing of Unit 2 HPCI pump, operators noted turbine speed and pump flow oscillations. Operators also observed an inlet drain pot high level alarm due to a failed drain valve. As previously documented in Inspection Report 50-254/265-95011, Section 6.1, the inspectors reviewed the licensee's corrective actions for the failure of the drain pot level switch and solenoid operated valve failure. The inspectors noted that testing of the limit switch and testing of Unit 2 HPCI after troubleshooting efforts were completed. The item remained open pending review of the licensee's root cause and corrective actions for the flow oscillations.

The licensee's initial response to the flow oscillations was to make a minor adjustment to the proportional band on the flow controller. However, subsequent testing revealed the problem still existed. The inspectors concluded the licensee's initial root cause evaluation was weak. The licensee assembled a multi-disciplined team to determine the root cause of the Unit 2 HPCI flow oscillations. The team had Operations test Unit 2 HPCI in multiple configurations. The team determined the position of the test valve was changed during the outage. This produced a lower discharge pressure during high pressure steam testing conditions. Since the flow controller was not adjusted to the new conditions, flow oscillations occurred. The team had the test return valve properly positioned and tested the flow controller response time.

The licensee initiated an increased testing frequency of both units' HPCI pumps in order to increase confidence with the system performance. In addition, the licensee purchased and trained personnel on use of air operated valve (AOV) diagnostic equipment. This equipment was part of a program to control and document air pressure settings for a growing selection of AOVs as well as detecting problems with AOV performance.

The inspectors determined the initial root cause evaluation of the HPCI flow oscillations was weak. However, the licensee's response team and the results produced by that team, led the inspectors to conclude the final root cause analysis was good. This item is closed.

E8.4 (Closed) Inspector Followup Item (50-254/265-96006-05): Main Steam Isolation Valve (MSIV) Spacer Plates Inadvertently Left Installed. The licensee performed a 10 CFR 50.59 safety evaluation to document that the spacer plates would not introduce any unanalyzed conditions adverse to safety. The licensee's determination of root cause was that recommendations communicated in the parts evaluation, to remove the spacer plates from the MSIVs, were not adequately processed by Engineering. Consequently, these recommendations were not implemented into the work packages by work analysts. Problem Identification Form 96-3018 was written to ensure future configuration control by establishing an all inclusive history table of the MSIVs and consolidating related PIFs from 1991 through 1996. A NTS item was assigned to identify and control removal of the 1-inch spacer plates during the next overhaul of each actuator. The inspector concluded that this failure to control design configuration was a violation of 10 CFR Part 50 Appendix B, Criterion III, "Design Control." The licensee's corrective actions to ensure safety, operability, and configuration control appeared adequate. This licensee identified and corrected violation is being treated as a **Non-Cited Violation (50-254/265-96020-07)**, consistent with Section VII.B.1 of the Enforcement Policy. This item is closed.

IV. Plant Support

R2 Status of Radiological Protection and Chemistry (RP&C) Equipment

R2.1 Unit 2 Radiological Liquid Effluent Monitor Flow Problems

a. Inspection Scope (71707)

The inspectors spoke to engineering and chemistry personnel and reviewed equipment calibration histories. The inspectors reviewed Section 11.5.2.7 of the UFSAR, Section 12 of the offsite dose calculation manual (ODCM) and the licensee's corrective actions for identified deficient conditions.

b. Observations and Findings

During tours of the facility, the inspectors identified an uncharacteristic non-turbulent flow condition in the Unit 2 liquid effluent radiation monitor flow indicator (bubbler). Subsequent verification of the eductor flow path indicated the flow return isolation valve had drifted about one half turn closed. Chemistry technicians operationally checked the flow switch to verify proper operation, then returned the valve to the normal position. The technicians determined that the valve position moved due to a loose packing nut and system vibration. The technicians tightened the packing nut and checked other similar valve packing nuts. The licensee documented this item on PIF 97-0035. Operations determined that the radiation monitors had remained operable during the time in question. The inspectors concluded the degraded flow condition was not enough to actuate the low flow alarm.

In response to questions asked by the inspectors, the system engineer identified the eduction system flow switch and pressure indicators were included in the licensee's instrument calibration program but were not required to be calibrated on a specified frequency. Previously, the licensee would clean the flow switch and then perform a functional test of both the radiation monitor and flow switch each refueling outage. Additionally, the system engineer identified a PIF commitment to clean the flow switch every 4 months was not implemented and there was no existing calibration procedure for the flow switch. The licensee documented these issues on PIF 97-0048.

The ODCM required calibration and functional tests of the radiation monitor but not of the flow switch or pressure indicators. However, the radiation monitor required proper operation of the flow switch and eduction system pressure indicators to ensure proper service water flows through the radiation monitor.

The inspectors asked the licensee what other instrumentation, necessary to ensure operability of safety-related equipment, was not maintained in the calibration program. The inspectors consider the adequacy of the licensee's calibration program to be an **Unresolved Item (50-254/265-96020-08)** pending review of the licensee's response.

c. Conclusions

The inspectors noted a potential weakness with the lack of calibration for instruments used to verify safety-related equipment operability.

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 January 24, 1997. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

E. Kraft, Site Vice President
B. Pearce, Station Manager
A. Blamey, Station Support Supervisor
D. Bucknell, Site Quality Verification
D. Cook, Operations Manager
J. Kudalis, Support Services Director
W. Lipscomb, Work Control Superintendent
M. Wayland, Maintenance Superintendent

INSPECTION PROCEDURES USED

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

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/265-96020-01	NCV	technical specification surveillances not performed within required time period
50-254/265-96020-02a	VIO	operator left SBGT "B" train control switch in off and did not verify that all annunciators were clear
50-254/265-96020-02b	VIO	operator recorded that the SBGT "B" train control switch was in the primary position and it was actually in the off position
50-254/265-96020-02c	VIO	operator used the notch override switch instead of the single notch withdraw to return the control rod to its original position after exercising
50-254/265-96020-03	VIO	improper testing of CREVS
50-254/265-96020-04	IFI	problems with shared EDG
50-254/265-96020-05	IFI	weak operability evaluation for the degraded safe shutdown makeup system valves
50-254/265-96020-06	IFI	design discrepancy with ECCS suction strainers
50-254/265-96020-07	NCV	failure to control design configuration
50-254/265-96020-08	URI	Unit 2 radiological liquid effluent monitor flow problems

Closed

50-254/265-95004-01	VIO	control rod HCU return to service after maintenance without being tested
50-254/95004	LER	Unit 1 HPCI failed to operate
50-265/95001-00 and 01	LER	valve seat leakage exceeded LLRT limits
50-254/265-95005-01	VIO	maintenance personnel failed to adhere to procedural requirements
50-254/265-95009-01	IFI	shared EDG failed to start due to failed relay
50-254/265-95006-01	IFI	Unit 2 reactor scram during EHC system testing
50-265/95005	LER	Unit 2 reactor scram during EHC system testing
50-254/265-95009-03	IFI	oscillations of Unit 2 HPCI pump
50-254/95008-00 and 01	LER	oscillations of Unit 2 HPCI pump
50-254/265-96006-05	IFI	MSIV spacer plates inadvertently left installed

LIST OF ACRONYMS AND INITIALISMS USED

ALARA	As Low as Reasonably Achievable
AOV	Air-Operated Valve
AR	Action Request
CAM	Containment Atmospheric Monitoring
CFR	Code of Federal Regulations
CRD	Control Rod Drive
CS	Core Spray
CREVS	Control Room Emergency Ventilation System
d/p	differential pressure
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control System
ENS	Emergency Notification System
EO	Equipment Operator
ER	Engineering Request
ft-lbs	foot-pounds
GL	Generic Letter
gpm	gallons per minute
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection System
IDNS	Illinois Department of Nuclear Safety
IFI	Inspector Followup Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
MSC	Motor Speed Changer
MMD	Mechanical Maintenance Department
MSIV	Main Steam Isolation Valve
MWe	Mega-watts Electric
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NSO	Nuclear Station Operator
NTS	Nuclear Tracking System
NUREG	Nuclear Regulatory Commission Technical Report Designation
ODCM	Offsite Dose Calculation Manual
OOS	Out-of-Service
PDR	Public Document Room
PFC	Procedure Field Change
PIF	Problem Identification Form
psi	Pounds per Square Inch
psid	Pounds per Square Inch Differential
psig	Pounds per Square Inch Gauge
QCAP	Quad Cities Administrative Procedure
QCEPM	Quad Cities Electrical Preventive Maintenance
QCOA	Quad Cities Operating Abnormal Procedure