U. S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-254/95007(DRP); 50-265/95007(DRP)

FACILITY
Quad Cities Nuclear Power Station, Units 1 and 2

Licensa Nos. DRP-29; DPR-30

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

DATES
September 2 through October 18, 1995

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11-7-95
Date

AREAS INSPECTED

The inspectors conducted a routine, unannounced inspection of operations, engineering, maintenance, and plant support, while routinely evaluating safety assessment and quality verification activities. The inspectors also performed followup inspection for non-routine events and for certain previously identified items.

Executive Summary

Operations Summary

Unit 1 remained at full power for the entire report period, with power reductions for testing and minor maintenance. Operating history for the unit was good, with few events, and no reactor trips. Unit 2 began the report period in startup from a forced outage caused by a reactor trip resulting from electro-hydraulic control system problems. Load was reduced to about 20 percent power due to a main condenser vacuum transient caused by an offgas condenser level control valve failure. Refueling outage startup testing was completed on about September 26, when the unit was brought to full power. On September 29, power was reduced to about 90 percent due to oscillations on the number (No.) 2 turbine control valve. The unit remained at or about this power for the remainder of the report period.

Operations

- Shift engineers aggressively questioned some of the engineering department's root cause evaluations. This resulted in improved root cause evaluations for reactor core isolation cooling (RCIC) and offgas system problems. (Section 1.0.)

- Operator attempts to recover from a loss of vacuum transient were hindered by poor procedures, use of inexperienced personnel, and errors in determining appropriate valve lineups. (Section 1.2.)

Maintenance and Surveillance

- The inspectors and licensee identified continued examples of failure to follow station procedures and policies, including an additional example of a violation previously cited in June 1995. (Section 2.1.)

- The inspectors identified examples where rework expended significant resources and limited availability of equipment to operators. (Section 2.2.)

- The maintenance department failed to control contract painter use of muriatic acid in the station blackout (SBO) diesel building. The result was significant damage to equipment on both SBO diesels. Inspector followup item (IFI) 50-254/265-95007-01(DRP) was opened to follow corrective actions for the event. (Section 2.3.)

Engineering and Technical Support

- Motor Control Center (MCC) 29-2 tripped on overcurrent, revealing a loading problem on safety related MCCs. Failure to take corrective action for bus overloading and failure to control MCC load growth were considered apparent violations (50-254/265-95007-02 & -03(DRS)). (Section 3.1.)

- The station made progress on improving Unit 2 material condition during the refueling outage. However, numerous longstanding equipment problems and operator workarounds remained. (Section 3.2.)

- The inspectors identified several material condition deficiencies which had not been identified by system engineering walkdowns. (Section 3.3.)

- Equipment failures caused the loss of availability of numerous pieces of safety equipment at various times throughout the report period. At times, the risk factor for the units from a single event increased. Poor engineering root cause evaluations contributed to continued equipment problems. (Section 3.4.)

- Core monitoring code computer errors caused Unit 2 operators to reduce power due to the appearance of exceeding core thermal limits. (Section 3.5.)

- The inspectors identified weaknesses in the licensee's dedication process for safety related condenser vacuum pressure switches. (Section 3.6.)

- The overall program for setpoint calculations was acceptable. However, a violation was issued for failure to assure that test instrumentation was adequate to meet applicable design documents (50-254/265-95007-04(DRS)). (Section 3.7.)

- Problems with high pressure coolant injection (HPCI) air operator valves (AOV) showed inservice testing (IST) weaknesses in administration of testing, control of test parameters, and root cause determination. (Section 3.8.)

Plant Support

- The inspectors and licensee identified several examples of radiation workers failing to follow station radiological policies and procedures. (Section 4.0.)

- The licensee identified about 20 problems with control of locked high radiation areas (LHRA) and high radiation areas (HRA) and assembled a task force to investigate common causes, recommend possible solutions, and develop an implementation plan for corrective actions. (Section 4.1.)

Safety Assessment and Quality Verification

- The plant operations review committee (PORC) and plant management failed to set rigorous standards for the standby diesel generator (SBDG) operability and engineering evaluations of HPCI AOVs. (Sections 3.4 and 3.8.)

Summary of Open Items

Violations: identified in Sections 2.1 and 3.7.

Apparent Violations: identified in Section 3.1.

Unresolved Items: not identified in this report.

Inspector Follow-up Items: identified in Section 2.3.

Non-cited Violations: not identified in this report.

INSPECTION DETAILS

1.0. OPERATIONS:

The inspectors used NRC Inspection Procedures 71707 and 93702 to evaluate plant operations. Operators responded well to poor material condition issues and to most resulting transients. Shift engineer questioning of engineering solutions resulted in more effective probing of the root causes for RCIC and offgas system problems. Procedure weaknesses and training deficiencies delayed efforts to mitigate a main condenser vacuum transient.

1.1. Followup of Events (93702)

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

September 4	Three Unit 1 HPCI air operated valves inoperable.
September 5	Unit 2 load drop due to loss of main condenser vacuum transient.
September 12	Emergency notification system (ENS) call. Failed encoder rendered Whiteside County sirens inoperable.
September 18	Unit 2 RCIC inoperable following testing.
September 26	Unit 2 Standby Diesel Generator (SBDG) failed to start during surveillance test.
September 29	Acid etching caused equipment failure for both station blackout (SBO) diesel generators.
October 4	ENS call. Bus 29-2 tripped due to overcurrent condition. October 4 Unit 2 HPCI inoperable due to failure to engage the turning gear.
October 5	Unit 2 power reduced to repair oscillating turbine control valve.
October 18	Unit 2 HPCI inoperable due to high steam inlet drain line pot level, a failed air operated steam line drain valve, and flow controller failure.

1.2. Main Condenser Vacuum Transient

The inspectors observed control room activities during a main condenser vacuum transient on September 5 and noted good response with some opportunities for improvement. Operators used annunciator response procedures and directed resources to reduce power and switch air ejector trains to mitigate the transient. However, cognitive errors, poor training and oversight, and poor procedures led to delays in putting the plant in a stable condition.

The vacuum transient was caused by an inoperable level control valve on the Unit 2 offgas air ejector condenser. This raised the water level in the condenser which reduced the effectiveness of removing non-condensible gasses.

The operators' first actions, in conjunction with reducing power, involved draining the offgas condenser back to the main condenser.

Initially, the wrong valve was used. Next, an operator, unfamiliar with key components of the offgas air ejector piping systems, was sent to open the correct valve. Control room personnel spent a significant amount of time trying to direct the operator to the proper valve.

The transient eventually ended when operators successfully switched from the "A" train to the "B" train of air ejectors. Operators delayed performing this evolution due, in part, to unfamiliarity with switching air ejectors and because there were no procedures to switch air ejector trains with the unit at power.

2.0. **MAINTENANCE:**

The inspectors used NRC Inspection Procedures 62703 and 61726 to evaluate maintenance and testing activities. Rework continued to be problematic, as did failure to follow station procedures and policies. The licensee strengthened the Fix It Now team to improve the ability to work more efficiently. The results of the effort were not conclusive at the end of the report period. The maintenance department failed to control contract painter use of muriatic acid in the station blackout (SBO) diesel building. The result was significant damage to equipment on both SBO diesels.

2.1. Failure to Follow Procedures

The inspectors and licensee identified continued examples of failure to follow station procedures and policies. These included:

- Failure to adhere to fundamental radiological practices prohibiting chewing and smoking in a radiological restricted area.
- Failure to maintain the watertight door to the "2B" RHR room closed during maintenance. The failure to maintain the "2B" RHR room door closed on October 4 was considered an additional example of a violation cited in June 1995 (50-254/265-95005-02a). The licensee was in the process of implementing the corrective actions when the violation was identified.

The inspectors concluded that despite station policies being widely disseminated, some plant workers still had not fully accepted procedure adherence. The inspectors will continue to monitor licensee progress in this area.

2.2. Rework

The inspectors noted extensive rework efforts for reactor and turbine building ventilation fans. During the report period, the inspectors observed operators having difficulty setting proper ventilation lineups from the control room because numerous reactor and turbine building ventilation fans remained inoperable. Many of these fans were on the operator work around lists and scheduled for repair; but the maintenance had been rescheduled several times. Examples of problems which delayed the ventilation systems from being repaired included:

- One new turbine building fan motor had been balanced, but the motor was improperly ordered with the wrong shaft.

- One turbine building exhaust fan was rebuilt, then installed and removed several times due to pitch problems, loose conduit, and a loose shaft key.
- One reactor building fan failed due to torquing requirements being exceeded when the fan was previously rebuilt.

These problems and continued repair efforts on the "2C" condensate pump seals were indicative of weaknesses in engineering, root cause evaluations, parts support, and maintenance work quality. The inspectors' overall concern was that equipment problems affecting operators continued while significant resource expenditures were used on rework.

2.3. Station Blackout (SBO) Electrical Equipment Tarnished by Muriatic Acid

The maintenance department failed to control contract painter use of muriatic acid in the Unit 1 station blackout (SBO) diesel building. The result was significant damage to electrical equipment on both SBO diesels. The Unit 2 SBO Diesel, which had been available, was declared inoperable due to damage to the battery charger's electrical components. The Unit 1 SBO Diesel was not yet available, and the licensee expected the equipment to require extensive refurbishment and some equipment replacement.

A contractor for Quad Cities applied a concentrated solution of muriatic acid to the unfinished concrete floor while preparing the surface for painting. The acid fumes permeated the entire electrical room for Unit 1 SBO Diesel which corroded electrical busses, contacts, and most terminal connections. The battery charger panel and the invertor also failed. The licensee requested an extension from the original commitment date for Unit 1 SBO Diesel until the next refueling cycle. The licensee expected to complete Unit 2 SBO Diesel refurbishment and retesting by December 31, 1995. The inspectors concluded that inadequate control of contractor work activities and the lack of restrictions prohibiting the use of muriatic acid near electrical equipment contributed to this event. The inspectors will follow the corrective actions as IFI 50-254/265-95007-01(DRP).

3.0. **ENGINEERING AND TECHNICAL SUPPORT:**

The inspectors used NRC Inspection Procedure 37551 to evaluate the engineering area. Engineers were more involved in plant testing and maintenance. Engineering training efforts improved with initiatives such as sending engineers to selected licensed operator certification classes. Engineering followup to ensure proper loading on 480 Vac motor control centers was poor. Several important pieces of equipment were inoperable during the report period as a result of poor material condition. Weak engineering root cause efforts were a contributing factor to problems with some equipment. The inspectors found material condition problems which could have been identified by more thorough system walkdowns. Instrument setpoint calculations were performed in an acceptable manner. However, design information contained in surveillance procedures was not properly controlled.

3.1. Overloading of 480 Vac Motor Control Centers (MCCs)

Quad Cities Plant Engineering failed to thoroughly investigate safety related MCCs that could be potentially overloaded. The result was that on October 4 with Unit 2 at power, MCC 29-2 tripped on overload. The breaker trip resulted in a loss of reactor protection system bus "B," numerous primary containment isolation system (PCIS) isolations, a loss of power to the residual heat removal service water vault cooling fans for pumps "C" & "D" ("B" Train of emergency core cooling system (ECCS)), loss of power to the "2B" SBDG air compressor and SBDG cooling water pump room cooler fans "A" and "B." The inoperability of the above equipment placed the unit in a 24-hour shutdown limiting condition for operation. The licensee's investigation found that MCC 29-2 was overloaded to about 318 amperes. The MCC 29-2 feed breaker overcurrent trip setting lower end tolerance (270-300 amperes) had not been readjusted to accommodate the MCC load.

A similar event occurred at Dresden in June 1994 when MCC 39-2 tripped on overload due to the uncontrolled addition of loads over time (load growth). Dresden identified two other MCCs that could be overloaded under certain conditions. Dresden's corrective actions included placing loading restrictions on the three MCCs, and increasing the trip settings.

Quad Cities was notified at least three times by internal ComEd documents about the Dresden event. The documents included Licensing followup package for Quad Cities Unresolved Item 50-254/265-94014-03(DRP), a Dresden lesson's learned initial notification, and Dresden licensee event report (LER) 94018. Additionally, as the result of a June 1994 study, ComEd corporate engineering notified Quad Cities of the potential for MCC 29-2, 18-1B, 18-2, 28-1B, and 28-2 feed breakers to trip because the maximum load current exceeded the feed breaker trip setting lower end tolerance. The worst case was MCC 18-2 which had an actual breaker setting of 300A and a maximum load current of 472A. Although this information was communicated to Quad Cities Site Engineering, MCC 18-2 was the only overload condition that was addressed and corrected. Additionally, the licensee was aware of, but had not corrected, current limiter problems on several station battery chargers. This could have resulted in additional MCC loading.

Corporate engineering's methodology used in investigating the Dresden event was not comprehensive. When similar conditions were identified at Quad Cities, corporate engineering had not ensured that corrective actions were implemented for these potentially overloaded MCCs. In addition, Quad Cities' technical staff lacked insight on how to interpret and use Electrical Load Monitoring System (ELMS-AC+) data even though responsibility for the Quad Cities ELMS-AC+ program had been transferred to Site Engineering in 1994. The licensee erroneously believed that programs already in place, such as the setpoint program, would correct any overcurrent conditions identified in the ELMS-AC+ data. The inspectors also noted that the licensee had recurring failures of both 125 Vdc and 250 Vdc battery chargers' current limiters which could allow more current to load the MCC feed breaker than documented in the ELMS-AC+ data.

The licensee failed to control load growth as a design activity. The licensee was unable to retrieve records which showed what loads had been added to the MCCs since original construction. Several original construction loads were only recently added to the ELMS-AC+ loading data base. As a result, the latest ELMS-AC+ data indicated that as many as six MCCs potentially could be overloaded under certain conditions. As of October 4, Site Engineering had not implemented actions to address the potentially overloaded MCCs and had not informed Site Operations regarding the additional challenge plant operators might face in coping with the loss of essential equipment. The inspectors reviewed the licensee's short term corrective actions which included administrative controls of loads on the potentially overloaded MCCs and had no immediate operability concerns. At the end of the report period, the licensee was performing a problem identification form (PIF) Level 2 investigation to identify the root causes.

Failure to correct the identified potential for safety related 480 Vac MCCs to trip on overload is contrary to 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," and is considered an apparent violation (50-254/265-95007-02(DRS)). In addition, the failure to establish an effective program to assure that MCC load growth was analyzed to prevent feed breaker tripping due to overloading is contrary to 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and is considered an apparent violation (50-254/265-95007-03(DRS)).

Licensee Corrective Actions

Short term corrective actions included the following:

- Administrative control of certain loads powered from the MCCs;
- Reviewed MCCs 18-2, 19-2, 28-2, 29-2, 18-1B, and 28-1B loads for actual equipment nameplate and manufacturer's data to update ELMS-AC+ load modeling;
- Reviewed drawings to assure the MCC loads were accurately identified.

The licensee's proposed long term corrective actions included:

- Raising the feed breaker trip settings; and
- Replacing cables with larger sizes as needed.

The inspectors will continue to follow the licensee's corrective actions for bus loading problems.

3.2. Material Conditions

Unit 2 refuel outage (Q2R13) startup testing was completed on September 26, and operators brought Unit 2 to full power for a short period. Significant material condition improvements during Q2R13 included:

- Main generator inspection and overhaul;
- Transformer 21 replacement;
- Station blackout diesel modifications to Busses 23, 23-1, 24, 24-1;
- "B" & "C" Residual Heat .emoval (RHR) service water motor refurbishments;
- "C" & "D" RHR motor refurbishments;
- "A" Core Spray (CS) motor refurbishments;
- HPCI pump alignment and pipe support installation;
- Reactor water cleanup piping and heat exchanger replacement;
- Electro-hydraulic Control system upgrades;
- Torus paint refurbishment;
- HPCI sparger installation;
- Core shroud inspection and repair;
- Reactor recirculation motor generator repairs;
- Control rod drive system refurbishment;
- Upgraded feedwater level control valves.

The licensee planned to address the following material condition issues during the planned February 1996 Unit 1 refuel outage:

- Core shroud repair and inspections,
- Electrical connection of station blackout diesel generator to Unit 1,
- Upgrade safety related motor operated valves in RHR and CS systems,
- Upgrade feedwater level control system in preparation for 3-element control,
- Repair cracked core spray T-box by use of a clamp, and
- Repair leak in 1B RHR Heat Exchanger.

Numerous equipment challenges remained for both units. Risk significant equipment failures this report period are identified in Section 3.4. Other problem areas affecting plant operation included:

- Several spurious computer uninterruptible power supply bus transfers;
- Several prime computer malfunctions, some of which effected core thermal limit monitoring;
- Core monitoring code thermal limit monitoring problems;
- Hydrogen addition system trips;
- Continued condensate demineralizer problems;
- Numerous ventilation equipment failures;
- Continued Unit 2 offgas perturbations;
- Numerous problems with cooling water temperature control valves sticking including reactor building closed cooling water valves which caused reactor recirculation pump seal pressure oscillations;

- Continued reactor recirculation pump speed control problems; and
- Unit 2 turbine control valve oscillations.

3.3. Material Condition Walkdown

The inspectors performed system and component walkdowns and noted deficiencies which included the following:

- Hydraulic control unit directional control valve solenoids interfered with scram inlet valve stroking;
- Degraded penetration between Unit 1 HPCI and RCIC rooms (not analyzed for steam line break);
- Supports for RHR piping missing hardware;
- Support for RCIC piping bent; and
- Conduit for torus temperature instrument separated exposing the cable.

Some of the items had not been previously identified, and some items, such as the degraded room penetrations and the torus temperature instrument, had been identified but not acted upon for over a year. The inspectors concluded that some monthly system engineering walkdowns were not effective in evaluating system deficiencies.

3.4. Increased Risk Due to Safety Equipment Failures

Equipment failures caused the loss of availability of numerous pieces of safety equipment at various times throughout the report period. Although the licensee met the requirements of technical specifications for operation of the units, at times, the risk factor for the units from a single event increased. Affected equipment included:

- Unit 2 standby diesel generator (SBDG) failed to start during testing;
- Three Unit 1 HPCI air operated valves (AOVs) inoperable due to slow stroke times;
- Unit 2 HPCI inoperable due to failure of the turning gear to engage;
- Unit 2 HPCI inoperable due to failed AOV and speed oscillations;
- Unit 2 RCIC inoperable due to suction piping over pressurization concerns;
- Unit 2 electrical loads from MCC 29-2 unavailable due to overcurrent trip, causing inoperability of a SBDG and residual heat removal service water pumps;
- Unit 2 station blackout (SBO) diesel made unavailable due to improper acid use, with Unit 1 SBO equipment also affected;
- Unit 1 Safety Relief Valve (SRV) 3B inoperable;
- Unit 1 SRV 3C downstream thermocouple inoperable; and
- Unit 1 SRV 3E indication problem.

Some of the engineering investigations were not thorough and some failed to identify the root causes. The inspectors noted the following weaknesses:

- Unit 2 SBDG Failure to Start

  On September 26, the Unit 2 SBDG failed to start during surveillance testing. Engineering followed the problem with PIF 95-2472. Engineering initially concluded the fuel priming pump motor caused the failure, but found no reason for the degradation. Additionally, engineers had not eliminated other possible root causes. Although age related degradation was first suspected, degradation on similar components was not sufficiently addressed. When the fuel priming pump and motor were later found to be in satisfactory condition, engineers elected not to pursue additional root causes for the SBDG failure. At the close of the report period, corrective actions for the PIF were overdue. The inspectors noted that operators had written a PIF in August 1995 which identified a slow SBDG start.

  On October 24 (which was after the report period), the Unit 2 SBDG failed to start during surveillance testing due to degraded air starting motors. Engineering determined that the slow start in August 1995 was related to the next two failures.

- HPCI Failures

  The inspectors concluded that a root cause investigation for the Unit 1 HPCI steam line drain AOVs lacked a thorough technical justification. This item is discussed in section 3.8 of the report.

  The root cause investigation for a failure of Unit 2 HPCI turning gear to engage had not repeated conditions of the original failure and failed to come up with a root cause for the event.

The inspectors discussed with station management the lack of rigor in some engineering investigations. Management agreed that root cause evaluations had not been consistently thorough, nor had the appropriate expectations for investigations been set by management.

3.5. Miscalculated Thermal Limits

Prime computer and process computer interface problems resulted in the miscalculation of reactor core thermal limits necessitating a rapid power reduction by operators. Operators responded properly to indications that core thermal power limits had exceeded the limit of 1.0. Actual thermal limits had not been exceeded. A computer booting error caused improper flags to be used in the core monitoring code computer. Although this caused conservative actions to be taken, the inspectors concluded that this type of error could cause non-conservative thermal limit monitoring. The licensee was addressing corrective actions for the computer boot sequence at the close of the report period. The inspectors will inspect the licensee's corrective actions in the next report period.

3.6. Poor Component Review Prior to Commercial Grade Dedication

The inspectors identified that neither the commercial grade dedication nor the modification processes reviewed performance history of vacuum pressure switches prior to installation.

The licensee identified that the condenser vacuum pressure switches (Barksdale model D1T-H18SS) exhibited setpoint drift and replaced the switches with identical model switches during the recent Unit 2 refueling outage. The licensee purchased the pressure switches as commercial grade products and upgraded the switches to safety grade in accordance with a commercial grade dedication process. However, neither the licensee's commercial grade dedication process nor the modification process reviewed the switches for historical performance. Based on licensee and industry information, the switch model had a poor performance history. The inspectors were concerned that the licensee's processes had not evaluated the poor historical performance of this switch model.

The licensee implemented a testing program for the switches and was evaluating the switches for a possible 10 CFR Part 21 notification. The licensee recognized weaknesses in testing material received from vendors and planned to have either the modification process or the design process address material performance issues prior to product installation.

3.7. Instrument & Control Setpoint and Modification Reviews

The inspectors reviewed selected instrument and control (I&C) setpoint calculations and modifications. The inspection focused on the design and configuration of safety related and important to safety instrumentation and control systems and components. The inspection purpose was to determine if: (1) selected instrument setpoints were properly derived such that automatic actions would occur to prevent safety limits from being exceeded; (2) calculations, supporting these setpoints, considered all appropriate uncertainties; (3) setpoint calculation methods were technically consistent with accepted standards; and (4) if I&C modifications were implemented according to station procedures.

The inspectors concluded the licensee was performing setpoint calculations in an acceptable manner. In addition, the modifications reviewed were implemented satisfactorily, the safety evaluations adequately demonstrated that an unreviewed safety question did not exist, and all aspects of the modifications reviewed were thoroughly tested. However, a weakness in controlling design input information obtained from surveillance procedures was identified. The translation of surveillance procedure design input information, such as test equipment accuracy, was not provided in a controlled manner to design engineering personnel for review.

The inspectors used Nuclear Engineering Department procedure No. TID-E/I&C-10, "Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy," and No. TID-E/I&C-20, "Basis for Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy," for the calculation review. In addition, the methods described in Instrument Society of America Standard No. ISA-RP67.04, Part II, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," were used. In particular, the setpoint methodology associated with the selected instrumentation loops were evaluated to determine if setpoints were correct and adequate safety margin existed. Instrument loop selection was based on the predominant accident scenarios identified in the individual plant examination (IPE) and the updated final safety analysis report (UFSAR). The inspectors reviewed the following setpoint calculations:

NED-I-EIC-0019	Drywell High Pressure Emergency Core Cooling System (ECCS) Initiation Setpoint Error Analysis at Normal Operating Conditions,
NED-I-EIC-0184	Torus Level Narrow Range Indication Error Analysis at Normal Operating Conditions,
NED-I-EIC-0232	Feedwater Flow Indication Error Analysis,
NED-I-EIC-0235	HPCI Pump Discharge Flow Loop Accuracy Calculation,
QC-CID-002	Suppression Pool Water Temp Instrument Loop Accuracy,
QC-CID-004	Suppression Pool Water Level Instrument Loop Accuracy (WR),
QC-CID-086	Main Steamline (MSL) Steam Low Pressure Switch Sensing Line Delay Time,
QC CID-089	Setpoint for MSL Low Pressure Group 1 Isolation Logic Time Delay Relay,
QC-CID-090	Isolation Channel Logic Response Time-Unit 2, and
QC-429-J-005	Calibration Range for HPCI flow Transmitter FT 2-2358.

The inspectors identified minor problems with significant digit carryover and probability symbol usage in calculation No. QC-CID-004. However, when factored into the calculation, there was little or no effect on the results.

The inspectors were concerned that a mechanism did not exist to control surveillance procedure information incorporated as design input information in setpoint calculations. Setpoint calculations used surveillance procedure calibration accuracy and measuring and test equipment (MTE) accuracy in the setpoint determination. Calculation No. NED-I-EIC-0019 used an MTE accuracy of ± 0.183 inches of water column (INWC) in developing the ECCS drywell high pressure setpoint. The calculation bounded the setpoint determination by using the least accurate MTE that the instrument mechanics (IMs) could select for performing surveillance procedure No. QCIS 1000-3, "Quarterly High Drywell Pressure Core Spray, Low Pressure Coolant Injection (LPCI), and SBDG Calibration and Functional Test." However, the procedure stated the MTE equipment requirement as "C.2. Certified pressure gauge (capable of measuring 0 to 166.0 in WC)" without stating an accuracy requirement. The inspectors identified that the May 12, 1995, performance of procedure QCIS 1000-3 used a Druck pressure gauge (QA No. 033269Q, range - 0 to 415 INWC). The Druck gauge accuracy (± 0.415 INWC) was outside the bounds of the MTE accuracy assumed in the setpoint calculation. The inspectors believed the procedure's MTE requirement was misleading. The pressure gauge selected was capable of meeting the 0 to 166 INWC requirement, but the gauge selected was less accurate than specified in design basis documents. A mechanism was not in place to control design input information specified in surveillance procedures. Following translation of the MTE requirements into the surveillance procedure No. QCIS 1000-3, the test control process had not included design engineering in the review process to ensure that the specified MTE would meet the acceptance limits contained in the setpoint calculation. Failure to assure that adequate test instrumentation was used to meet applicable design documents is considered a violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," (50-254/265-95007-04(DRS)).

The licensee determined that sufficient margin existed between the as-left calibrated setpoint and the channel functional acceptance criteria to accommodate the additional MTE inaccuracy. The licensee also concluded that the drywell high pressure channels were operable. The inspectors noted that sufficient margin existed in the setpoint calculation for the drywell channels to remain operable through the next calibration interval. In addition, the licensee indicated that a formal mechanism was being developed to link procedures with design input information to design calculations. At the end of the report period, the licensee was in the process of reviewing additional surveillance procedures to ensure that appropriate MTE were being used by maintenance personnel.

Modification Inspection Details

The inspectors reviewed several modifications. The reviews included the intent of the design change, the safety evaluation, and the post-modification test. In addition, several modifications were walked down. The following modifications were reviewed:

M04-2-92-019	MSL Low Pressure Group 1 Isolation Circuitry Time Delay Relay Addition,
E04-2-93-174	Replace High Drywell Pressure Switches, and
E04-2-93-226	GE/MAC Feedwater Differential Pressure Transmitter Replacement.

The inspectors concluded the licensee had implemented the modifications in an acceptable manner.

3.8. Poor Engineering Evaluation of Unit 1 HPCI Valve Inoperability

On September 4, operators determined that three HPCI system AOVs were inoperable, but had not requested written documentation to justify HPCI system operability. System engineering had failed to take corrective action with regard to trending adverse AOV stroke times. System engineering also failed to meet the requirements of recent inservice testing (IST) program changes that required classifying these slow trending valves in the "required action" range. Plant management failed to set an appropriate expectation for the depth of technical evaluations.

The inspector asked the on-shift, shift engineer (SE) why the HPCI system for Unit 1 was considered operable since an IST surveillance test (QCOS 2300-6) performed on the previous shift identified three inoperable system AOVs. The SE on the previous shift had determined the system status as operable, based on verbal justification by the system engineer. Following the inspectors questions, the on-shift SE asked system engineering to formally respond to questions concerning HPCI system operability. The closing times on the AOVs in question had been in the "alert" range on previous IST surveillances. Recent IST program changes included changing the previous "alert" range to a "required action" range. Therefore, within the current test, these AOVs were inoperable.

Several days later system engineering presented justification for HPCI system operability to the plant operations review committee (PORC). The inspectors attended the PORC review and noted the following weaknesses:

- No engineering root cause was provided for the trend of increasing stroke times of the AOVs.

- Engineering had not evaluated the type of valve, valve orientation, maintenance and replacement history, or similarity to failures of other AOVs. Instead, engineers relied simply on the success of past surveillances to justify operability, even though an increased stroke time trend was evident.

- Engineers had not set appropriate criteria for valve testing. System parameters were allowed to vary sufficiently from test to test to introduce uncertainty into the results for stroke time testing values.

- The PORC members failed to set a rigorous standard for operability determinations. Instead, PORC members accepted recommendations from engineering without requiring sufficient technical justification for the increased stroke times.

At the close of the report period, Unit 2 HPCI was shut down during surveillance testing due, in part, to failure of a separate steam line drain AOV to open. The inspectors will continued to evaluated the effectiveness of the licensee's root cause evaluations for HPCI AOV and other failures.

4.0. PLANT SUPPORT:

The inspectors used NRC Inspection Procedures 71750 and 92904 to evaluate plant support activities. The licensee implemented a program to keep all instruments and tools used in the radiologically protected areas (RPA) from being released from the RPA. The licensee planned to move potentially contaminated electrical and instrument maintenance work areas from the service building into the laundry and tool decontamination building. Additionally, the licensee placed greater restrictions for releasing material from the RPA. The licensee reduced the amount of contaminated areas by continuing decontamination efforts. However, the station dose remained high relative to industry standards. On numerous occasions, the licensee had not met daily dose goals mostly due to unanticipated expansion of work in high radiation areas. The inspectors identified instances when workers did not meet management expectations of performance in radiological areas including improper clothing and maintenance practices. The licensee also identified evidence of improper radiological practices in radiologically controlled areas. The licensee identified numerous problems associated with control of high radiation areas and assembled a task force to investigate root causes.

4.1. Radiation Protection (83750)

Control of High Radiation Areas

Since January 1994, the licensee identified about 20 problems with control of locked high radiation areas (LHRA) and high radiation areas (HRA). The licensee assembled a task force to investigate common causes, recommend possible solutions, and develop an implementation plan for corrective actions. The task force utilized onsite staff led by an offsite contractor and collected procedures and information to compare Quad Cities radiation protection practices with five other nuclear facilities.

The inspectors reviewed the task force charter and believed that weaknesses identified by the licensee were included. The inspectors will review corrective actions resulting from this effort.

5.0 ISSUE RESOLUTION:

The inspectors used NRC Inspection Procedures 92701 and 92702 to review previously identified items and to ensure that corrective actions were accomplished in accordance with the technical specifications. This included reviewing the responses to inspection followup items (IFIs) and licensee event reports (LERs).

5.1. IFIs Reviewed:

(Closed) Inspection Followup Item 50-254/265-92002-01 (DRS): Emergency Operating Procedures (EOPs). The licensee committed to document how EOP plant specific technical guidelines (PST) were translated into EOP flowchart procedures. During this inspection, the inspectors verified that the transition from PST to EOPs was documented. The inspectors considered the documentation comprehensive and effective in showing how PST steps were translated into flowchart steps. No significant discrepancies were identified. This item is closed.

(Closed) Inspection Followup Item 50-254/265-94004-42: Engineering Support. The Course of Action and 1995 Management Plan detailed specific engineering goals to improve engineering support. Improved operator work around and control room nuclear work request tracking has focused attention on important plant problems. The inspectors determined that progress in this area was slow but noticeable. Specific improvements will be mentioned as part of the licensee's management plan review. This item is closed.

5.2. LERs Reviewed:

(Closed) LER 254/90026, Rev 1: Control Room Isolation on High Toxic Gas Concentration. On December 20, 1990, the control room ventilation system isolated due to an Erasable Programmable Read Only Memory (EPROM) not being compatible with the software. The EPROM was updated by a minor design change. The inspectors reviewed the completed design change and noted improved performance of the toxic gas analyzer. This item is closed.

(Closed) LER 254/91024: Fire Mitigation System for SBDGs Does Not Meet Design Flow Rate. During testing the licensee identified that the carbon dioxide (CO_2) concentrations registered in the Unit 1 and shared diesel generator rooms failed to meet fire code (NFPA-12) concentration requirements within a 1 minute time period. The licensee attributed the event to incorrect discharge nozzles installed. The correct nozzles were installed and the tests were reperformed. The tests passed marginally. The licensee then increased the CO_2 discharge times. The inspectors reviewed the work histories and the licensees test evaluation report. This item is closed.

6.0. EXIT INTERVIEW

The inspectors met with the licensee representatives denoted below during the inspection period and at the conclusion of the inspection on October 18, 1995. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

The following management representatives attended the exit meeting conducted on October 18, 1995, along with others.

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Bill Pearce, Station Manager
Ron Baumer, Regulatory Assurance
N. Chrissotimos, Regulatory Assurance Supervisor
John Hutchinson, Site Engineering Manager
Ed Kraft, Site Vice President
John Kudalis, Support Services Director
Dennis Winchester, Site QV Director