U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/89022(DRP); No. 50-249/89021(DRP)

Docket Nos. 50-237; 50-249 Licenses No. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Dresden Nuclear Power Station, Units 2 and 3

Inspection At: Dresden Site, Morris, Illinois

Inspection Conducted: October 11 through December 1, 1989

Inspectors: S. G. Du Pont
D. E. Hills

Approved By: J. M. Hinds, Jr., Chief
Reactor Projects Section 1B

12/26/89
Date

Inspection Summary

Inspection during the period of October 11 through December 1, 1989 (Report No. 50-237/89022(DRP); No. 50-249/89021(DRP))
Areas Inspected: Routine unannounced safety inspection by resident inspectors of previously identified inspection items, licensee event reports, plant operations, maintenance and surveillance, safety assessment/qualify verification, engineering/technical support and report review.
Results:

- Specific events demonstrating management involvement and a regard for correctly meeting requirements as well as for minimizing unplanned transients were noted.

- One violation was identified during the inspection period as described in Paragraph 5.b.8. This involved the failure to properly control the design of a penetration through a fire barrier such that maintenance personnel degraded that barrier on two separate occasions. This specific event was considered to be of minimum safety significance although a previous degradation of a fire barrier by maintenance personnel was documented in a previous inspection report. This was not considered to be indicative of what are usually thorough and effective corrective actions by the licensee.

- Two unresolved items were identified in Paragraphs 5.b.5 and 7.b.3. One involved whether adequate corrective actions were taken in response to previously identified HPCI piping support discrepancies. The other involved installation of main steamline leak detection temperature switches without the appropriate environmental qualification documentation.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Technical Superintendent
E. Mantel, Services Director
*J. Kotowski, Production Superintendent
D. Van Pelt, Assistant Superintendent, Maintenance
J. Achterberg, Assistant Superintendent, Work Planning
*G. Smith, Assistant Superintendent, Operations
*K. Peterman, Regulatory Assurance Supervisor
*C. Allen, Performance Improvement Supervisor
W. Pietryga, Operating Engineer
*R. Stobert, Operating Engineer
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
*M. Strait, Technical Staff Supervisor
L. Johnson, Q.C. Supervisor
J. Mayer, Station Security Administrator
*D. Morey, Chemistry Services Supervisor
*D. Saccomando, Health Physics Services Supervisor
E. Netzel, Q.A. Superintendent
*R. Falbo, Regulatory Assurance Group Leader
K. Yates, Nuclear Safety Supervisor
*K. Kociuba, Quality Assurance Superintendent

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, electrical, mechanical and instrument personnel, and contract security personnel.

*Denotes those attending one or more exit interviews conducted informally at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Open) Open Item (No. 249/89011-02): The licensee was to provide a written response describing planned corrective actions to ensure that usage of the isolation condenser for extended time periods without offsite power would not result in radioactive releases. The latest response to this issue by the licensee was contained in the letter from J. A. Silady to A. B. Davis dated November 15, 1989. A tentative schedule was established for the respective unit refueling outages at the end of Cycle 13 in 1992 to install diesel driven pumps for supply of clean demineralized water to the shell side of the isolation condensers from the clean demineralized water storage tank. A proposed design improvement to supply 480 VAC power to the isolation condenser shell side motor-operated clean demineralized water fill valves was being reviewed with respect to impact on the

Appendix R safe shutdown analysis. The licensee committed to providing a final update concerning this part of the design within two months of the date of the letter.

No violations or deviations were identified in this area.

3. Licensee Event Reports (LER) Followup (90712 and 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished or planned in accordance with Technical Specifications.

(Closed) LER No. 237/89025: Inadvertent Automatic Isolation of the High Pressure Coolant Injection (HPCI) System Due to Design Deficiency. The activities resulting in this occurrence were discussed in inspection report No. 50-237/89019; No. 50-249/89018. The licensee attributed the root cause of this event to a design deficiency within the Analog Trip System (ATS) panel such that the master trip unit (MTU) mounting configuration can result in spurious trips when adjacent MTUs are removed. The licensee determined that Dresden Instrument Surveillance (DIS) 2300-11, System Isolation-Reactor Pressure Transmitter Calibration and Maintenance Inspection, was the only HPCI instrument surveillance procedure that required removal of adjacent MTUs. Therefore, the licensee planned to incorporate precautions in this procedure to exhibit care when removing and replacing MTUs and to require prior notification to the Operations Shift Supervisor that MTU replacement may result in an isolation signal. The licensee also planned to post signs on the ATS panels to indicate the same caution and requirement. The licensee did not plan to change the MTU mounting configuration since they considered this to be an isolated event and MTU removal was a rare occurrence due to a high reliability of the component.

(Closed) LER No. 237/89026: Start of Standby Gas Treatment System Due to Loose Reactor Building Ventilation System Radiation Monitor Connection. This event including initial licensee actions was described in inspection report No. 50-237/89019; No. 50-249/89018. In addition, the licensee planned to revise DIS 1700-7, Reactor Building Ventilation (RBV) Radiation Monitor Functional Test, to require checking RBV radiation monitors for loose connections and exposed wiring during the surveillance. The licensee also planned to evaluate possible methods to improve instrument department response time to this type of event and to evaluate a generic radiation monitor troubleshooting procedure.

(Closed) LER No. 237/89027: Postulated Low Pressure Coolant Injection (LPCI) Swing Bus Loss Resulting From Diesel Generator Voltage Regulator Failure Due to Design Deficiency. This item and corresponding licensee actions are described in Paragraphs 7.b.1 and 7.c of this report.

(Closed) LER No. 237/89028: Containment Cooling Service Water (CCSW) Pump Suction Bay Water Level Reduction. This event was discussed in inspection report No. 50-237/89019; No. 50-249/89018. As a long term corrective action, the licensee planned to review methods to proceduralize a program that was initiated to measure water level drop across the trash bars. This would contribute to earlier recognize of CCSW suction level bay decreases.

(Closed) LER No. 237/89029: Elevated HPCI Discharge Piping Temperature Due to Reactor Feedwater System Back Leakage. This item and corresponding licensee actions are described in Paragraphs 5.b.4, 5.b.5 and 7.c of this report and report No. 50-237/89023; and No. 50-249/89022.

(Closed) LER No. 237/89030: Reactor Building Fire Wall Degraded By An Unauthorized Penetration Opening Due to Management Deficiency. This item and corresponding short term licensee actions are described in Paragraphs 5.b.8 and 5.c of this report.

(Closed) LER No. 249/89004: HPCI System Declared Inoperable Due to Failed Room Cooler Fan Drive Belts. This item and corresponding licensee actions are described in Paragraph 5.b.3 of this report.

No violations or deviations were identified in this area except as described in Paragraph 5.b.8 of this report.

4. Plant Operations (71707, 71710 and 93702)

a. Enforcement History

During this inspection period, no violations or deviations were identified in the plant operations functional area.

b. Operational Events

On October 10, 1989, the Unit 2/3 Cribhouse Basement Cable Tray Fire Suppression Deluge System was inadvertently actuated during performance of Dresden Fire Protection Procedure (DFPP) 4114-6, Fire System Yard Loop Monthly Inspection, Revision 10. While inspecting the protectowire fire alarm control panel and power supply for the cribhouse basement cable tray fire detection system, fire panel 2223-112, the operator attempted to replace burned out light bulbs as required by the procedure. In order to identify the burned out bulbs, the operator depressed a panel button labeled Alarm Devices-Push to Test, which he thought would just illuminate the panel lights. However, this button instead tested the fire panel relays which actuated the deluge system spraying water into the Unit 2/3 cribhouse basement. The operator immediately isolated flow by breaking the locking device on cribhouse cable tray isolation valve 2/3-4199-176 and closing the valve. A second initiation occurred later that same day due to grounds on the protectowire located in the cable trays which were caused by water from the first initiation. The area was allowed to dry out and inspections revealed no other equipment damage.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint

The licensee exhibited regard toward ensuring operators were aware of adverse conditions, their affect on the plant and mitigation techniques. This was exemplified by informing operators of an alternate method to determine if Electrohydraulic Control (EHC) DC power were lost as described in Paragraph 5.b.1 of this report. Due to a relay failure at that time, a loss of EHC DC power would have rendered various main turbine trips inoperable without a corresponding alarm to warn the operator of this condition. Questioning of the operators by the inspectors indicated that they were aware of the alternate method.

The licensee's investigation into the inadvertent deluge system actuation represented a thorough and comprehensive root cause analysis and corresponding corrective actions. The licensee attributed the cause to inaccurate labeling which did not make the function of the pushbutton apparent. In addition, DFPP 4114-6 was deficient in that it did not caution the operator concerning this pushbutton. Finally, the licensee determined that operator training was deficient in that the fire system lesson plan also did not provide this information. As a result, the licensee installed an additional label below the pushbutton that read Push to Initiate Deluge. The licensee also proposed the following corrective actions to ensure this event would not be repeated with respect to other fire protection panels:

(1) Discuss the event in Operations and Maintenance tailgate sessions such that personnel are aware of this pushbutton in protectowire fire panels.

(2) Identify all protectowire fire panels that have an equivalent pushbutton and provide the additional warning labels below each of the pushbuttons.

(3) Revise DFPP 4114-6 to identify protectowire fire panels which do not contain a light test button.

(4) Revise the fire system training lesson plan to include this event and to stress the existence of this pushbutton.

(5) Determine the requirements for having the pushbutton in protectowire fire panels and remove those not required.

d. Responsiveness to NRC Concerns

Issuance of Dresden Operating Abnormal (DOA) Procedure 0500-02, Partial Half or Full Scram Actuation, in November 1989 was in response to NRC concerns and indicated the ability to apply lessons learned from other plants. This procedure prescribed mitigating operator actions upon a half or full scram for which Reactor

Protection System scram solenoid indicating lights do not extinguish as they should. This procedure was developed as a result of commitments made to the NRC following such an event at Commonwealth Edison's LaSalle plant.

e. Assurance of Quality, Including Management Involvement and Control

The licensee's decision involving when to initiate a Unit 2 shutdown due to the HPCI piping support damage as discussed in Paragraph 5.b.4 of this report demonstrated management involvement and a desire to ensure that technical specification requirements were met. Previous licensee guidance had concerned the case in which a 24 hour shutdown Limiting Condition for Operation (LCO) was immediately entered. In that case, the licensee's interpretation did not require immediately reducing power if it was legitimately felt that the problem could be rectified and the LCO exited in sufficient time such that an orderly shutdown could still be completed within the original 24 hours if needed. However, the case in question differed from previous guidance in that a seven day LCO was entered prior to entry into the 24 hour shutdown LCO verses being immediately placed into the 24 hour shutdown LCO. Thus, the guidance was unclear as it applied to this situation. To ensure compliance with the requirements, the licensee consulted with NRC regional upper management as to the applicability of previous guidance to this situation. As the licensee felt that actions to consider the system operable could be completed within 12 hours, the decision was made to actually begin the shutdown 12 hours after entry into the 24 hour LCO. This left enough time for completion of an orderly shutdown within the original 24 hours in case the actions did not get completed on time. When the actions were not completed on time, the licensee initiated the shutdown at the time agreed to with the NRC. The inspectors also noted during discussions with licensed operators regarding the incident that they possessed a genuine desire to ensure conservative compliance with technical specifications and, in fact, were concerned as to what appeared to several of them to be actions possibly contrary to previous guidance that they had received in this area. The inspectors regarded this concern to be indicative of a professional attitude of the licensed operators toward their individual licensed responsibilities.

f. Observation of Operations

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during this period. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of Units 2 and 3 reactor buildings and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance. The inspectors also walked down various HPCI piping supports to ascertain damage and verify repairs as described in Paragraphs 5.b.4 and 5.b.5 of this report.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors reviewed new procedures and changes to procedures that were implemented during the inspection period. The review consisted of a verification for accuracy, correctness, and compliance with regulatory requirements.

The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under Technical Specifications, 10 CFR, and administrative procedures.

5. Maintenance and Surveillance (62703, 61726 and 93702)

a. Enforcement History

During this inspection period, one violation was identified in the maintenance/surveillance functional area. This concerned a failure to properly control the design of a penetration through a fire barrier such that maintenance personnel degraded that barrier on two separate occasions.

b. Operational Events

Various maintenance activities associated with the following events were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review:

The LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance.

(1) On October 12, 1989, alarms for EHC DC Power Failure and EHC Electrical Malfunction were received on Unit 3. This was of particular concern since loss of EHC DC power would render many of the main turbine trips inoperable. Troubleshooting activities conducted by instrument maintenance and witnessed by the inspectors indicated that DC power was still available and that the alarm relay itself was malfunctioning. However, it was decided not to replace the relay since such an action would be highly susceptible to causing a main turbine trip. The relay in question was located on a circuit card which also contained several other trip relays. These relays were of a mercury type such that inappropriate movement when replacing the card could cause a trip. Thus, the licensee intended to wait until the next time power was reduced to less than 45% to repair the problem so that a turbine trip would not also result in a reactor scram.

(2) On October 15, 1989, the breaker for the Unit 2 LPCI Room Cooler B was found to have been damaged when operators investigated a report that smoke was seen coming from the breaker. The inoperability of the room cooler also required Core Spray Loop B and LPCI Loop B to be declared inoperable, placing Unit 2 into a 24 hour required shutdown LCO. The breaker was, however, repaired later that same day such that the shutdown did not have to commence.

(3) On October 22, 1989, the Unit 3 HPCI System was declared inoperable due to discovery of broken fan belts on the HPCI room cooler. This placed the unit into a seven day LCO. The belts were replaced and the system declared operable on October 23, 1989. The licensee had previously planned to take the room cooler out-of-service on October 23, 1989, for bearing work. Thus, this activity was also completed. A previous event concerning Unit 2 HPCI room cooler broken fan belts was discussed in inspection report No. 50-237/89019; No. 50-249/89018. The root cause of that event was determined to be excessive use of the room cooler due to elevated HPCI room temperatures caused by feedwater system backleakage into the feedwater lines. Increased HPCI line temperatures eventually led to inoperability of the Unit 2 HPCI system as discussed in Paragraph 5.b.4 of this report. However, the licensee indicated that the Unit 3 HPCI room and the HPCI line temperatures were much less than on Unit 2. Thus, the licensee initially indicated that these events were unrelated and backleakage was not a problem on Unit 3 HPCI.

The licensee attributed the cause of the Unit 3 HPCI room cooler belt failure to be shaft misalignment due to the worn bearing. Although the exact cause of the worn bearing was unknown, the most probable cause was inappropriate drive belt tensioning. Dresden Electrical Procedure (DEP) 5700-4, Electrical Maintenance and Surveillance of HPCI Room Fan Motors,

instructed the user to ensure proper belt tension was achieved but gave no additional guidance as to what this tension should be. Therefore, the licensee planned to revise DEP 5700-4 to include proper belt tension information.

(4) On October 23, 1989, the licensee found the Unit 2 HPCI system discharge piping water temperature to be sufficiently high to potentially cause voids to form within the piping. Piping temperatures were discovered to have increased to 275 degrees F between HPCI pump discharge outboard valve 2-2301-8 and HPCI pump discharge inboard valve 2-2301-9, 246 degrees F at the HPCI pump and 135 degrees F near the condensate storage tank (CST). The corresponding static pressure in the HPCI discharge piping at the pump was 32 psig (47 psia). Thus, temperature and pressure in particular areas of the system, represented possible saturated conditions which the licensee believed provided the potential for a waterhammer event. Therefore, the licensee declared the Unit 2 HPCI system inoperable and entered a seven day LCO. On October 27-28, 1989, the licensee discovered numerous signs of damage to various Unit 2 HPCI discharge piping supports. An unusual event (UE) was declared on October 31, 1989, when the licensee initiated a technical specification required shutdown due to a failure to return the HPCI system to operability within the seven day LCO. The system was returned to operability that same day prior to completion of the shutdown. This event, including licensee corrective actions, was discussed in detail in inspection report No. 50-237/89023; No. 50-249/89022. A clamp on Unit 2 HPCI piping support M-1151D-154 located on top of the torus was identified to be rotated on the pipe and a work request initiated during the last Unit 2 refueling outage. However, this work request was not completed during that outage. This is considered part of an unresolved item (No. 237/89022-01(DRP)), together with the item in Paragraph 5.b.5 of this report, pending NRC review and determination of why this work was deferred.

(5) On October 29, 1989, the licensee found the Unit 3 HPCI system discharge piping temperature at an elbow of the piping near its emergence from the X-area (steam tunnel) to be 256 degrees F. Additional measurements obtained on October 31, 1989, indicated piping temperature just upstream on the other side of the elbow measured between 163 and 133 degrees F depending on the circumference location. The corresponding static pressure in the HPCI discharge piping at the pump was about 45 psig (60 psia). The licensee believed temperature and pressure conditions near the elbow could potentially cause steam pocket formation. Thus, the licensee declared the Unit 3 HPCI system inoperable. On November 1, 1989, the licensee also discovered signs of damage to Unit 3 HPCI piping supports. The Unit 3 HPCI system was returned to service on November 7, 1989. This event including

licensee corrective actions, was discussed in detail in inspection report No. 50-237/89023; No. 50-249/89022. Unit 3 HPCI piping support M-1187D-110 was found to have the baseplate and all four concrete expansion anchors pulled from the wall. Evidence also showed that a licensee walkdown conducted in 1979 noted a wallmount pulling away. This is considered part of an unresolved item (No. 237/89022-01(DRP)), together with the item in Paragraph 5.b.4 of this report, pending NRC determination of whether this is the same damage as originally identified.

(6) On November 6, 1989, the Unit 2 HPCI Motor Gear Unit (MGU) high speed stop (HSS) indicating light was discovered to be blinking on and off. However, the MGU was still functional since it automatically returned to it's HSS from it's low speed stop (LSS). A large amount of noise was discovered in the DC output signal and, thus, the HPCI MGU was taken out of service to repair it on November 8, 1989. The MGU HSS indication fluctuations were eliminated by replacement of a circuit capacitor and HPCI was declared operable on November 10, 1989.

(7) Throughout much of the inspection period, Unit 2 operated at slightly reduced power due to repeated spurious primary containment half isolation signals received at full power conditions. These half isolations were caused by failure of main steamline low pressure switch PS-261-30B. The licensee believed that rapid pressure fluctuations within the pressure line caused by vibration was prematurely degrading the bourdon tube within the switch. This had been a recurring problem in the past with previous actions involving vibration testing of the main steamline low pressure switches and installation of a pressure snubber in the sensing line. The switch had been replaced several times but would typically fail after approximately one month. Load was reduced to 65 percent on November 18, 1989, in order to allow entry to the heater bay to conduct a walkdown of the sensing line. This walkdown did not identify any problems with the line. On November 22, 1989, PS-261-30B was replaced and a new portion of sensing line on the instrument rack was installed in a looped configuration in hopes of dampening any pressure fluctuations to the switch. The licensee was also evaluating possible future replacement with a different and less susceptible type switch.

(8) On October 26, 1989, the Station Manager discovered a three inch open penetration stuffed with rags in a three hour fire rated wall separating the Units 2 and 3 reactor buildings at elevation 570 feet. The mechanical maintenance department was in the process of dismantling and cleaning an area on the Unit 2 side of the wall which was formerly a control rod drive (CRD) maintenance area. The work being performed under a blanket work request for general plant cleanup was not intended to disrupt or alter plant components or systems. A drain line connected to a CRD flush tank had previously been routed

through the penetration to a floor drain on the opposite side of the wall. Due to high radiation levels from the drain line and the fact that the CRD flush tank was to be removed during the cleanup, removal of the drain line was also added to the scope of the work. Maintenance personnel did not realize that the wall was a rated fire barrier or that it would be degraded by the open penetration, although a nearby fire door in the same wall was present and easily identifiable. Under a normal work request, a determination by the working department would have been required as to whether a fire hazard review by the fire marshall should be accomplished during the work planning stage. This would have included a review to determine the applicability of DFPP 4175-1, Fire Barrier Integrity and Maintenance, and DFPP 4175-2, Operating Fire Stop/Break Surveillance. However, a blanket work request bypassed these types of controls. Approximately 24 hours elapsed between the time the piping was removed from the penetration and discovery by the Station Manager. During this period of time, an hourly fire watch, although required as a result of the inoperable penetration by Dresden Administrative Technical Requirement (DATR) 3.1.6.1, did not exist. The DATRs were first implemented on August 29, 1989, to incorporate fire protection requirements that were deleted from technical specifications as described in Paragraph 7.b.2 of this report.

A previous event also involving degradation of a fire barrier by maintenance personnel occurred on June 14, 1989. Failing to recognize a fire barrier, workers routed a welding cable and air hose through an unducted ventilation opening in the fire wall separating the Unit 3 east LPCI room and the Unit 3 HPCI room. This prevented closure of an automatic vertical fire damper in the ventilation opening. The technical specification requirement in effect at that time required a continuous fire watch to be established within one hour due to the inoperable fire barrier penetration. This was not established until the degradation was discovered three days after it occurred. This event was described in inspection report No. 50-237/89017; No. 50-249/89016. NRC review indicated that this previous event met the criteria of 10 CFR 2, Appendix C, and thus no notice of violation was issued at that time. Corrective action to prevent recurrence involved marking of unducted ventilation openings in fire barriers to make them more recognizable and, therefore, was very specific to that event. This corrective action also was not complete at the time of this latest occurrence in that of five identified unducted ventilation openings in fire barriers only one had already been appropriately marked. The remaining were to be completed during the December 1989 Unit 3 refueling outage. This action did not address the broader aspects of maintenance personnel recognition of fire barriers in general and, therefore, could not have prevented this latest occurrence even if it had been completed.

Further review by the licensee determined that the rated fire assembly penetration had been degraded even prior to the piping removal. The penetration was originally installed in 1982. However, at some date between April 1, 1985 and July 8, 1985 sections of the piping including the portion going through the penetration were replaced with polyvinyl chloride (PVC) plastic piping, a non-approved material for fire barrier penetrations. Plastic materials will burn with an intensity and heat production in a range similar to that of ordinary hydrocarbons. In addition, when burning, they produce heavy smoke that obscures visibility and can plug air filters. The halogenated plastics also release free chlorine and hydrogen chloride when burning, which are toxic to humans and corrosive to equipment. The work request under which this change was completed indicated that no fire hazards review was necessary.

The design drawing, fire barrier location drawing F-88, failed to identify the penetration. Drawing F-88 was inspected by the architect-engineer (AE) for fire barrier drawing development on February 14, 1985. This inspection was to identify all penetrations in the fire wall including both mechanical and electrical penetrations.

In addition, performance of surveillance DFPP 4175-2 failed to identify the existence of the penetration. This surveillance, required to be performed on an 18 month cycle, contained specific instructions to enter data on the Operating Fire Stop Surveillance Log and initiate a drawing change request for the appropriate fire protection drawing if a fire barrier penetration was found that was not on the drawings. Instructions for review of mechanical penetration seals were incorporated into the procedure on December 29, 1986 with Revision 5 of the procedure. Previous revisions required inspection only with respect to electrical fire seal penetration configurations. Inspections per this procedure including those pertaining to mechanical penetration seals were accomplished on February 1, 1988 and again on February 1, 1989, each time failing to identify the penetration in question.

This is considered to be a violation of 10 CFR 50.48(a) (No. 237/89022-02(DRP)) in that the licensee failed to control the design for this fire rated assembly (fire wall). The penetration was not identified during Appendix R walkdowns, was not included on fire protection drawings, and was not identified through the fire protection surveillances on the fire barrier. Furthermore, the fire rated wall was degraded in 1985 by installation of combustible PVC piping and again recently with complete removal of the piping. Each time, the effect on the fire barrier was not properly analyzed or considered. The cause of the more recent degradation of the fire barrier was, in fact, similar in nature to a fire barrier degradation which occurred earlier this year. In both, maintenance personnel failed to recognize a fire barrier and, therefore, the effect their actions would have on it.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint

The licensee's approach to resolution of technical issues in the maintenance area was mixed as demonstrated by the violation associated with the fire barrier degradation as opposed to the actions associated with the EHC DC power failure alarm relay.

Licensee corrective actions to the June 1989 fire barrier degradation by maintenance personnel, in retrospect, proved to be too narrow in scope to prevent another fire barrier degradation. Upon discovery of the later degraded fire barrier described in Paragraph 5.b.8 of this report, the licensee initiated an hourly fire watch. A temporary fire seal was installed on October 26, 1989, and a permanent seal was installed on November 17, 1989, when proper materials were available. The decision to wait for better conditions prior to replacing the EHC DC power failure alarm relay as described in Paragraph 5.b.1 of this report was an example of a regard for minimization of unplanned transients. In this way, if a main turbine trip would result from the activity, it would not also cause a reactor scram. The inspectors also noted that instrument maintenance personnel troubleshooting the problem were highly knowledgeable of detailed EHC system circuitry design. Licensee actions taken in response to the main steamline low pressure switch failures was regarded by the inspectors to be a good attempt to identify the specific problem and resolve it.

d. Responsiveness to NRC Initiatives

The licensee's timeliness of control room work request completions continued to be in response to NRC concerns. To ensure prompt resolution of such problems the licensee revised Operations Department Policy Statement Number 16. This statement established a white work request sticker for the control room to be used in addition to the existing salmon colored stickers. A salmon sticker was to be used to identify problems with control room indications such that the operator could no longer believe the indication or the indication was no longer available. A white sticker was used to identify problems that required corrective maintenance but control room indications were not affected. Salmon stickers were to receive a B-1 priority which required work to start within 24 hours if parts were available.

e. Observation of Surveillance Activities

The inspectors observed surveillance testing required by Technical Specifications for the items listed below and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met, that removal and restoration of the affected components were accomplished, that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities pertaining to Units 2 and/or 3:

Local Power Range Monitor (LPRM) Amplifier Gain Calibration
Average Power Range Monitor (APRM) Gain Adjustment
Individual LPRM Recovery
Quarterly Primary Containment Isolation Valve Timing
APRM Rod Block and Scram Functional Test
Intermediate Range Monitor Downscale Rod Block Functional Test
HPCI Valve Operability Test

6. Safety Assessment/Quality Verification (40500)

a. Enforcement History

During this inspection period, no violations or deviations were identified in the safety assessment/quality verification functional area.

b. Assurance of Quality, Including Management Involvement and Control

Management involvement in assuring quality was evident when the plant manager discovered the degraded fire wall as described in Paragraph 5.b.8 of this report. The inspectors continued to note frequent and effective tours of the plant by management.

The inspectors observed the monthly performance review meeting conducted on October 13, 1989. Plant management reviewed items of interest which occurred since the last meeting including engineered safety feature actuations, specific Technical Specification limiting conditions for operation entered, continuous or occurring control room alarms, degraded or out of service equipment and potentially significant events. In addition, the status of the top technical issues was discussed. In order to facilitate greater sharing of information with similar facilities, a representative from the Quad Cities plant was also present. In addition, the meeting was attended by a licensed plant operator who presented his own areas of concern. The inspectors considered attendance by both these individuals to be beneficial toward maintaining management awareness and involvement in relevant issues both internal and external to the plant. Attendance by plant operators also tended to promote greater professionalism and a sense of responsibility among that group.

The inspectors also reviewed the monthly status report for the month of October. The inspectors found this to be an excellent management tool for remaining cognizant and identifying trends in various departmental indicators.

7. Engineering/Technical Support (37828 and 93702)

a. Enforcement History

During this inspection period, no violations or deviations were identified in the engineering/technical support functional area.

b. Operational Events

(1) The licensee informed the resident inspectors on October 12, 1989, that they had confirmed a possible single failure that could occur during a loss of coolant accident (LOCA) following a loss of offsite power that could prevent the low pressure coolant injection (LPCI) swing bus, MCC 28-7/29-7 on Unit 2 (MCC 38-7/39-7 on Unit 3), from performing its intended function. The LPCI swing bus could be supplied power from either bus 28 or bus 29 on Unit 2 (bus 38 or bus 39 on Unit 3) which in turn were supplied power from opposite engineered safety feature (ESF) divisional buses. A low voltage condition on the LPCI swing bus was designed to cause an automatic transfer of the bus to the bus supplied from the other division. However, a diesel generator could suffer a voltage regulator failure such that voltage would be too low to properly operate bus loads but not low enough to cause the LPCI swing bus to automatically transfer to the division supplied by the other diesel generator. The LPCI injection valves were supplied power from the LPCI swing bus. Thus, the LPCI system and one division of core spray would be incapable of automatic injection in this scenario. This would leave only one core spray pump for automatic low pressure emergency core cooling system (ECCS) injection.

(2) On November 16, 1989, the licensee discovered that a DATR involving a fire detection instrument had been inadvertently missed. Technical Specification amendment numbers 106 for Unit 2 and 101 for Unit 3 removed the fire protection requirements from technical specifications in accordance with guidance presented in Generic Letters 86-10 and 88-12. The DATRs incorporated these technical specification requirements while also including the fire protection features added during the 10 CFR 50 Appendix R fire protection modifications. This included the addition of LCO actions to reflect the added fire protection features. These technical specification amendments were approved by the NRC on June 29, 1989, with 60 days given to implement the change. In preparation for implementation, work requests were reviewed by the system engineer and the fire marshall to see if inoperable equipment was affected by the DATRs. A total of 26 work requests were identified including one involving the Unit 3 LPCI room/torus fire detection (protectowire) device which was written on July 26, 1989. The associated DATR 3.1.1.1 LCO action statement required a once per hour fire inspection to be established within one hour. However, the work request review inappropriately identified

another action statement which was applicable to the other work requests as also applicable to this work request. This other action statement allowed 14 days to restore the device prior to establishing the fire watch. Thus, when the DATRs became effective on August 29, 1989, the fire watch was not established. On September 12, 1989, when the 14 days expired, the fire watch was established and a deviation report written. The device was repaired and considered operable on September 23, 1989. While reviewing the deviation report on November 16, 1989, the system engineer discovered the error.

The inspectors regarded this incident as an isolated occurrence induced by implementation of the new program requirements and a review process which differed from normal practices. The inspectors had not noted any further problems with DATR compliance under normal practices since their implementation, except as described in Paragraph 5.b.8 of this report. This exception, however, was attributable to a different root cause.

(3) While assembling work packages to install and calibrate United Electric Temperature switches for main steamline and HPCI steamline leak detection and automatic isolation, the licensee discovered that the model F100 switches to be installed were not referenced in the environmental qualification (EQ) binder. Further review by the licensee on November 14, 1989, indicated that five of the 16 Unit 2 main steamline temperature switches were already installed without the proper EQ documentation. One of these was installed in February 1989 and the other four in July 1989. The other Unit 2 main steamline, as well as all Unit 3 main steamline and Units 2 and 3 HPCI steamline temperature switches were properly EQ qualified model F7 switches. Although the suitability of application previously completed by the licensee for the F100 switch indicated that it was EQ qualified, this determination was based on a vendor test report and not on the required EQ binder. This is considered to be an unresolved item (No. 237/89022-03(DRP)) pending further NRC review of this matter.

c. Approach to The Identification and Resolution of Technical Issues From a Safety Standpoint

The licensee's determination of the LPCI swing bus design problem indicated a commitment toward remaining cognizant of industry issues and problems that could be relevant to Dresden. The review that identified this problem was implemented in response to similar deficiencies discovered at other nuclear power plants. Licensee subsequent actions included evaluating possible design changes and contacting the facilities with similar identified deficiencies to ascertain their respective courses of action. Two possibilities that were under review included additional protective relays or powering the involved motor control centers with an uninterrupted power supply. The licensee also issued Dresden General Abnormal

(DGA) Procedure 5, Degraded Voltage on MCC 29-7/28-7 (39-7/38-7) Due to a Failure of the Unit 2(3) Diesel Generator Voltage Regulator During a LOCA/Loss of Offsite Power Event. This procedure required the operator to trip the diesel generator if adequate voltage could not be restored such that the LPCI swing bus would automatically transfer. If this attempt failed, the operator was instructed to manually transfer the LPCI swing bus.

The inspectors regarded the missed DATR concerning the fire protection protectowire device to be an excellent example of a commitment to self-identification of problems by not only the licensee but also the individual who discovered and reported his own error. The licensee planned to include a discussion of the incident in station personnel tailgate sessions and in the licensed operator requalification continuing training program. The licensee also identified the EQ problem regarding five of the Unit 2 main steamline temperature switches. As a result, the licensee completed equipment qualification variation form 89-023 including a justification for continued operation. An EQ binder was also being developed to rectify the problem.

The inspectors regarded the licensee investigation, root cause analysis and corrective actions concerning the HPCI system backleakage and damaged piping supports, as described in Paragraphs 5.b.4 and 5.b.5 of this report as an example of aggressive self identification and resolution of problems. The review of elevated room temperatures and corresponding actions which led to discovery of the feedwater backleakage into the HPCI system was particularly insightful. The system walkdowns used to identify the HPCI support damage were very detailed and comprehensive. In addition, safety evaluations performed to support alternate HPCI system standby lineups addressed all relevant issues. Planned licensee actions to determine the root cause of HPCI system valve leakage, to access the effectiveness of the Inservice Inspection (ISI) program as it applied to structural supports and to perform similar walkdowns on other systems indicated an excellent attitude toward self-identification and assessment.

d. Responsiveness to NRC Concerns

The plant technical staff was responsive to a regional NRC request for information regarding maintenance of shutdown margin requirements during refueling.

8. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for October. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16. The inspectors also reviewed the Unit 2 Cycle 12 Startup Test Report Summary and confirmed that it met the requirements of Technical Specification 6.6.A.1.

9. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. Unresolved items disclosed during the inspection are discussed in Paragraphs 5.b.4, 5.b.5 and 7.b.3 of this report.

10. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on December 1, 1989, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.