U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/89019(DRP); 50-249/89018(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: August 29 through October 10, 1989

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

R. M. Lerch

Approved By: R. M. Lerch, Acting Chief
Reactor Projects Section 1B

10/30/89
Date

Inspection Summary

Inspection during the period of August 29 through October 10, 1989 (Reports No. 50-237/89019(DRP); No. 50-249/89018(DRP)).

Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, licensee event reports, plant operations, maintenance and surveillance, safety assessment/quality verification, engineering/technical support, emergency preparedness, systematic evaluation program items and report review.

Results:

- Two violations were identified during the inspection period as described in Paragraph 4.b. One involved a violation of Technical Specifications when a reactor water level switch for emergency core cooling system actuation was isolated without being placed in a tripped condition. The other involved a failure to perform an adequate independent verification during implementation of an equipment outage checklist resulting in a half scram. Both violations involved licensed operator inattentiveness to detail.

- A licensee review of the circumstances leading to entry into a 24 hour limiting condition for operation (LCO) involving the Unit 2 low pressure coolant injection (LPCI) system and the Unit 2 diesel generator, identified a number of deficiencies in the engineering/technical support functional area. These were addressed by proposed licensee corrective actions as described in Paragraph 7.b.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Technical Superintendent
E. Mantel, Services Director
C. Allen, Administrative Service Superintendent
*D. Van Pelt, Assistant Superintendent, Maintenance
J. Kotowski, Production Superintendent
J. Achterberg, Assistant Superintendent, Work Planning
*G. Smith, Assistant Superintendent, Operations
*K. Peterman, Regulatory Assurance Supervisor
W. Pietryga, Operating Engineer
*R. Stobert, 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

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)

(Closed) Violation (No. 237/86015-01): Failure to assure that changes and modifications to as-built drawings are properly controlled and implemented, and to assure that the as-built drawings are kept updated to reflect the actual condition of the plant. NRC Region III management and resident inspectors reviewed this item and determined that this item is closed administratively due to the lack of continuing safety significance since several NRC inspections have not detected any additional or continuing concerns associated with this item.

(Closed) Unresolved Item (No. 237/89018-02): Entry into 24 hour LCO involving Unit 2 LPCI system loop B and Unit 2 diesel generator. On August 7, 1989, while performing the LPCI quarterly flow rate test, the flow rate through loop B was below the required 14,500 gpm. No flow problems had been encountered during a previous LPCI system pump operability test. Prior to taking any action, the flow rate increased to an acceptable range on its own during the test. The licensee considered various possible causes including calibration of the flow transmitter, an opening system relief valve, or a problem with the LPCI test return valves or minimum flow valve. The Unit 2 diesel generator had been scheduled to be taken out of service for its semi-annual inspection but this was delayed pending study of the LPCI system problem. The licensee systematically eliminated these possible causes. For example, although a disk to stem separation had previously occurred on a LPCI test return valve causing a similar problem, a current trace showed the valve to be acceptable.

Another quarterly flow test was conducted on August 17, 1989, to determine the source of the restriction, and to verify that the system was operable prior to taking the Unit 2 diesel generator out of service. During this test, the required flow of 14,500 gpm was met although the test return valve had to be throttled completely open. When flow was transferred to the A loop and then back through the B loop, the flow was found to have increased to 15,500 gpm. Although this difference was indicative of a problem, the Operating Engineer was informed only that the required flowrate was achieved and not of the flow difference.

As a final check, current traces were obtained on LPCI outboard injection valves 2-1501-21A and B. These traces were compared to each other by electrical maintenance personnel and the running currents were considerably different, this was attributed to a known worn wormgear on the actuator of the 2-1501-21A valve. However, these current traces were not compared to previous current traces. There was also a noticeable difference in stroke times but a review of in-service testing (IST) stroke times indicated that the values were to be expected. The LPCI system was determined to be operable and the Unit 2 diesel generator was taken out of service on August 21, 1989.

On August 21, 1989, the General Electric (GE) site representative and the motor operated valve (MOV) coordinator discussed the differences between the 2-1501-21 A and B valves' stroke times. The MOV coordinator had not been directly involved in the problem analysis prior to August 21, 1989. They believed that different limit switch settings may have caused the stroke time differences. They requested that the valves be manually stroked opened to determine the distance between their back seats and the open limit switches. This testing was conducted on August 22, 1989, and showed that 2-1501-21A opened 7/8 inches before contacting its backseat while the 2-1501-21B valve was opened over two inches before stroking was stopped due to abnormal sounds from the valve body. Further testing to determine full stroke lengths indicated that no backseat could be found for the 2-1501-21B valve. The licensee determined that the valve plunger had separated from the stem and thus declared the valve inoperable. Since the Unit 2 diesel generator was currently inoperable, this placed Unit 2 into a 24 hour LCO. The licensee reassembled the diesel generator, filled the fuel oil storage tank, which was being drained for cleaning, and successfully tested the diesel generator later that same day (within the 24 hour LCO). Repairs to the LPCI outboard injection valve were completed on August 28, 1989.

An analysis as to the adequacy of the licensee's actions pertaining to this event and the affect on system operability are discussed in Paragraph 7.b of this report.

(Closed) Unresolved Item (No. 249/89005-03): This item is administratively closed due to duplication with a Unit 2 item (No. 237/89005-03). This item is being tracked and reviewed under the applicable Unit 2 item number.

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. 237/88017-01: High Pressure Coolant Injection (HPCI) System Intentionally Made Inoperable to Facilitate Pre-planned Preventative Maintenance Testing. During the HPCI overspeed trip test that was conducted prior to the start of the Unit 2 outage, minor hydraulic oscillations of the HPCI turbine governor were observed. The licensee investigation during the outage determined that these instabilities were due to excessive wear of the HPCI auxiliary oil pump which provided hydraulic control oil to the HPCI turbine control mechanisms. The licensee found that the original impeller shaft on the oil pump had been sized incorrectly which allowed the pump impeller to ride on the pump's casing. Resulting metal chips inhibited oil flow to the speed governor assembly. In addition, impeller contact with the pump casing caused variations in pump speed. A new impeller shaft of the correct size was installed and the hydraulic system piping was flushed. These oscillations were not observed when the testing was repeated following the refueling outage. Since the Unit 3 HPCI turbine had not demonstrated these types of oscillations, inspections for this problem had not been scheduled until the next refueling outage.

(Closed) LER No. 249/89001 and No. 249/89001-01: Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss of Offsite Power. This event and corresponding licensee actions were the subject of Inspection Reports No. 50-237/89012; No. 50-249/89011.

(Closed) LER No. 249/89006: Reactor Scram Caused by Turbine Stop Valve Closure Due to Control Relay Failure. This event which occurred on April 15, 1989, and corresponding licensee actions were discussed in Inspection Reports No. 50-237/89011; No. 50-249/89010. In addition to the actions delineated in that report, the licensee planned to revise the Operational Analysis Division (OAD) Protective Relay Calibration Procedure to clarify the physical inspection section such that mechanical binding of the relay pivot arm is specifically covered. This was to address the failure of the main generator secondary reverse power relay during the event. This failure was attributed to dirt located between the bearing and contact pivot arm on the relay directional unit. A similar failure occurred during another event on March 30, 1989, which the licensee had attributed to the operator not allowing the relays sufficient time to react prior to manually tripping the turbine-generator. The licensee's root cause was revised for the first occurrence as a result of this second occurrence.

(Closed) LER No. 237/89015: Trip of the 2A Reactor Protection System (RPS) Motor Generator (MG) Set Due to High Ambient Temperatures. This event resulted in a loss of RPS Bus B and thus power to reactor building ventilation radiation monitor B. This caused a half scram and an automatic start of the standby gas treatment system. One of the continuous run thermal overloads was found to have tripped. As corrective action, the thermal overload contacts were cleaned. Approximately four days later, the event recurred at which time the licensee attributed the problem to high temperatures in the motor control center cubicle. Thus, the thermal overload heater size was increased and the thermal overload setting was increased from 100 to 115 percent in accordance with the setpoint change control administrative procedure. The licensee also planned to replace the thermal overloads with ambient compensated thermal overloads.

(Closed) LER No. 237/89021: Inadvertent Group V Primary Containment Isolation Due to Wire Lug Failure. This event and corresponding licensee actions were discussed in Inspection Reports No. 50-237/89018; No. 50-249/89017.

(Closed) LER No. 237/89022: HPCI System Inoperable Due to Room Cooler Broken Drive Belts. This event and the more immediate licensee actions taken were discussed in Inspection Reports No. 50-237/89018; No. 50-249/89017. Additional long term corrective actions included a heat load analysis of the HPCI room to determine the cause of elevated HPCI room ambient temperatures. These high temperatures had necessitated increased use of the room cooler. This analysis determined that feedwater backflow past HPCI injection motor operated valve MO 2-2301-8 and check valve 2-2301-7 was the probable cause of the elevated temperatures. Work requests were written to repair these valves during the next refueling outage.

(Closed) LER No. 237/89023: Possible Single Failure Loss of Unit 2 Atmospheric Containment Atmosphere Dilution/Containment Atmosphere Monitoring (CAM) and Unit 3 CAM Due to a Design Deficiency. This deficiency was discussed in Inspection Reports No. 50-237/89018; No. 50-249/89017 and resolution to this issue is being tracked by previously Unresolved Item No. 50-237/89018-03.

(Closed) LER No. 237/89024: Downscale Trip Not Inserted During Emergency Core Cooling System Initiating Instrument Repairs Due to Management Deficiency. This event and licensee corrective actions are discussed in Paragraphs 4.b and 4.c of this report.

No violations or deviations were identified in this area except as described in Paragraph 4.b of this report.

4. Plant Operations (71707 and 93702)

a. Enforcement History

During this inspection period, two violations were identified in the plant operations functional area. One of these concerned a failure to adequately perform an independent verification during implementation of an Equipment Outage Checklist, which resulted in an unexpected half scram.

The other involved a Technical Specification violation when a reactor low low water level indicating switch for emergency core cooling system initiation was isolated without being placed in a tripped condition.

b. Operational Events

(1) On August 30, 1989, a Shift Foreman entering the Unit 2 Turbine Building to Reactor Building interlock, noticed that both interlock doors were open simultaneously. Electrical maintenance personnel were entering the opposite door and a security guard was already in the interlock. The doors were open for only 20 seconds and reactor building to atmosphere negative differential pressure was maintained. The normal door pushbuttons had been used and further checks indicated that the door functioned properly. In addition, the fuses for the door latches were checked due to previous problems encountered with other interlock doors. No reason was found as to how both doors could be opened at the same time. The licensee is continuing to monitor the interlocks.

(2) On August 30, 1989, Unit 2 Level Indicating Switch (LIS) 2-263-72C was not placed in a tripped condition when taken out of service which was contrary to technical specification requirements. This was one of four switches that provided the low low level (-59 inches) automatic initiation logic for core spray, low pressure coolant injection, automatic pressure relief permissive, high pressure coolant injection, standby gas treatment and the Unit 2 and 2/3 diesel generators. While performing a routine surveillance, instrument technicians noted a fitting that was leaking on a sensing line at the instrument rack. It was decided to repair the leak which required isolating LIS 2-263-72C. Both the Operating Engineer and Shift Engineer were aware of the applicability of Technical Specification Table 3.2.2 Note 1 which required its trip system to be tripped when that instrument was made inoperable. They were under the assumption that this would be done in conjunction with the work package which they indicated in the night orders and informed the instrument maintenance scheduler. However, the instrument maintenance foreman was not informed and, this action was not included in the work package. The Shift Control Room Engineer's (SCRE) review of the work package was inadequate, in that, through questioning of the

instrument technicians and actual review of the documentation, he did not ascertain that they planned to fail the instrument upscale instead of the required downscale to satisfy technical specifications. The SCRE marked a box on the maintenance procedure indicating that technical specification action was required, indicating he was aware of the requirement. The work package instructions clearly indicated the planned isolation and equalization of the instrument and did not contain any other guidance as to failure mode of the instrument. The SCRE also discussed the work with instrument department personnel including the need to fail that particular instrument prior to signing approval for commencement of work. The larger part of this discussion concerned how to isolate the instrument without introducing adverse perturbations in the system. However, the instrument department personnel mistakenly thought that failure in the upscale direction by isolating and equalizing the instrument was adequate. Upon isolation and equalization of the instrument, the indiction drifted upscale. The Shift Engineer was later performing control room panel walkdowns and noted that indication and alarms were not as would be expected if the instrument had been failed in the correct direction and initiated corrective actions to meet the technical specification requirements. Subsequent licensee investigation determined that this condition had existed for approximately one hour and fifty minutes. This failure to place LIS 2-263-72C in the tripped condition contrary to Technical Specification requirements is considered a violation (No. 50-237/89019-01(DRP)). Specific licensee corrective actions and the inspectors' evaluation of these actions are described in Paragraph 4.c of this report.

(3) On September 21, 1989, while conducting out-of-service (OOS) II-1209, an unexpected Channel B half scram occurred on Unit 2 when an incorrect fuse was pulled. This OOS was being performed in order to conduct a calibration of Main Steam Line (MSL) Low Pressure Switch (PS) 2-261-30B. A Nuclear Station Operator, a licensed reactor operator was performing the OOS with the SCRE, a licensed senior reactor operator, acting as the independent verifier. The correct fuse to remove, 595-703D, was to have resulted in a half group I isolation signal. Another fuse, 590-703D, in the same control room panel fuse block was incorrectly identified by both individuals as the fuse to remove which instead resulted in the half scram. Immediately following the half scram, the fuse was replaced and the correct one removed.

The fuses were clearly identifiable with the correct numbers on tape attached to the wire leading to each fuse. In addition, the tapes for the scram fuses were orange in color while those for the isolation fuses were black in color. Labels on the outside of the panel corresponding to the fuse block locations were also correctly numbered and color coded. The Equipment Outage Checklist also clearly identified the correct fuse to remove. The individuals were inattentive to detail in that they compared only the last part of the fuse number to the actual plant labeling. In addition, the individuals ignored or were confused by the color coding, which should have indicated that additional caution was warranted. Dresden Administrative Procedure (DAP) 7-27, Independent Verifications, Revision 0, required that independent verifications ensure that each check constitutes an actual component identification. Failure to adequately perform the independent verification is considered to be a violation (No. 50-237/89019-02(DRP)). Specific licensee corrective actions and the inspectors' evaluation of these actions are described in Paragraph 4.c of this report.

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

The licensee's approach to the identification and resolution of technical issues in the plant operations functional area was not as thorough as would be expected by previous performance in this area.

Various operator performance aspects of the September 21, 1989, half-scram event were comparable to a full scram which occurred on March 4, 1989. This full scram and corresponding violation were described in Inspection Reports No. 50-237/89005; No. 50-249/89005. The full scram was attributed to a non-licensed operator not using a procedure while checking for grounds and, thereby, causing incorrect breakers to be opened. In addition, the operator ignored corresponding color-coded labels which identified the prohibited breakers since their colors had recently been changed from what he was accustomed to seeing. In the case of the latter half scram, two licensed operators failed to adequately identify the correct fuse listed in an equipment outage checklist and thus removed an incorrect fuse. These operators also ignored or were confused regarding differences in color of the identification labels which should have indicted to them that caution would be advised. Thus, both violations involved a general inattention to detail regarding deficiencies in operators usage of documents governing the activity and their usage of colored labels that could have assisted in that activity.

Licensee actions taken in regard to the previous scram involved ensuring operators were familiar with both the specific procedure and identification of the specific circuit breakers. Licensee actions taken in regard to the half scram included counseling the involved individuals concerning properly identifying fuses prior to removal and plans to include the event in the licensed operator requalification program. However, it was not clear whether these actions would specifically address the failure to adequately follow provisions in the independent verification administrative procedure. This was of particular concern since it represented a circumvention of controls specifically instituted to prevent these types of errors. The inspectors expressed this concern to licensee management.

Licensee actions taken in response to the isolated level instrument not being placed in the tripped condition included reviewing the event with involved personnel and plans to include it in a station tailgate session. In addition, the licensee planned to develop a Technical Specification policy statement to clarify trip requirements for inoperable reactor protection system, primary containment isolation system and emergency core cooling system initiating instrumentation. This guidance would detail how these trips were to be inserted. While the inspectors believed this Technical Specification policy statement was an excellent idea, the corrective actions regarding the SCRE's involvement were less than adequate. The SCRE was aware of the Technical Specification requirement and even discussed the requirement with the instrument technicians. However, his review of the work package was deficient in that he did not ascertain as to how the instrument was to be failed or verify that correct instrument failure actions were actually contained in the work request itself. General practices concerning review of work packages prior to authorizing the work to start differed considerably since procedural guidance was not clear. These practices, dependent upon the individual performing the review, could involve questioning of the involved workers, review of the work package itself and/or both. An inspector review of Dresden Administrative Procedure (DAP) 15-1, Work Request, Revision 21 and DAP 15-3, Preparation of Safety-Related, Regulatory Related or Reliability Related Work Packages on Off-Shifts, Revision 2, indicated that little guidance was given as to the methods to be employed in conducting this review, including items to be verified, documentation to be physically reviewed and level of detail required in this review. Although individuals were required to complete a Precautions Taken for Reactor Safety and Technical Specifications Compliance checklist, this checklist did not address all of the aspects on how to conduct a thorough review and, in this case, was insufficient to preclude the event.

A detailed review prior to authorizing performance of a work request is necessary when work packages are prepared essentially independent of actual plant conditions. For example, many work packages have already been prepared for the upcoming, Unit 3, December 1989, refueling outage. Since it is impossible to forecast all future plant conditions when a work request is prepared, a detailed review of the work package just prior to implementation is essential to identifying any potential problems. The administrative guidance currently provided is inadequate to assure a detailed review is performed.

Individual operator performance including approach to technical issues was mixed during the inspection period as opposed to the excellent performance exhibited in this area during the previous inspection period. The half-scram that was received on September 21, 1989, when an incorrect fuse was removed, and the level instrument that was allowed to be isolated without being placed in a tripped condition, contrary to technical specifications, were indicative of an inattentiveness to detail by licensed operators. The Shift Engineer who noted by control room panel indications that the level instrument had not been tripped was particularly astute in identifying the problem. However, in contrast, other individuals were present in the control room and could have also identified the problem earlier but did not. In addition, the Shift Foreman who noticed that both Unit 2 Turbine Building to Reactor Building interlock doors were open simultaneously showed good attentiveness and strong regard for proper functioning of equipment. Finally, the operator who noticed the inoperable Unit 2 fuel zone level indicator as described in Paragraph 5.b of this report was also astute in identifying the problem.

d. Assurance of Quality, Including Management Involvement and Control

The inspectors noted a strong commitment on the part of management to ensure compliance with Technical Specifications. This was indicated by plans to develop a Technical Specification policy statement which would provide guidance on how to comply with specific action statements requiring tripping of various instrumentation. This was necessitated by recent events in which backshift interpretations of somewhat ambiguous Technical Specification action statements had to be made. As these circumstances were not considered ideal under which to make these decisions, the licensee believed that this guidance would be beneficial.

One of these recent events concerned the inoperable fuel zone level indicator discussed in Paragraph 5.b of this report. Licensee management was very involved in the interpretation as to the method to simulate a tripped condition for the failed Unit 3 fuel zone level indicator and showed a conservative approach to safety in this involvement. By failing the instrument in a low level condition, use of the override switch would have been required to initiate containment spray. Thus, the intent of the override switch remained; that is to prevent inadvertent initiation of the system. This arrangement required the override switch to also be re-positioned to initiate containment spray with level above two-thirds core height. This was not required under normal circumstances. However, since containment spray initiation was normally a manual operation, this was not regarded as detrimental. Caution tags were hung explaining this arrangement and control room operators were instructed on the conditions of the containment spray system.

e. 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. During this inspection period, no violations of the fire protection program were observed.

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, no violations or deviations were identified in the maintenance and surveillance functional area.

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 August 30, 1989, Unit 2 fuel zone level indicator B was determined to be inoperable when operators noticed an indication different from the expected. This instrument provided input to the LPCI system logic to prevent inadvertent initiation of containment spray. Containment spray initiation is normally accomplished by the manual operation of various valves. If less than two-thirds core coverage existed as indicated by the fuel zone level instruments a manual override switch would be required to be re-positioned to allow containment spray initiation. If greater than two-thirds core coverage, the position of this switch would have no effect on the ability to initiate containment spray. This arrangement provides additional assurance that flow would not be inadvertently taken from LPCI system injection into the vessel during conditions when vessel level could not be maintained above the two-thirds core coverage. Dresden Technical Specification Table 3.2.2 required that if an instrument was inoperable, it was to be placed in the tripped condition so that it would not prevent containment spray. The licensee accomplished this by installing a jumper which continuously simulated a less than two-thirds core height signal to the circuitry. A failed Rosemont transmitter was subsequently replaced and satisfactorily tested and the jumper was removed.

(2) On September 5, 1989, the licensee declared all four Containment Cooling Service Water (CCSW) pumps inoperable on both units due to low suction level in the service water suction bays. Neither the main circulation or service water systems were affected during the event. The licensee found that the suction bay screens were fouled due to a recent rain storm washing grass and other debris down the Kankakee River, one of two rivers feeding the Illinois River. The Kankakee River is normally a shallow river and was easily affected by rain wash off. With all of the CCSW pumps inoperable the licensee entered a 24 hour LCO. Later that same day the licensee returned three CCSW pumps on Unit 3 and two on Unit 2 back to service by flooding the suction bays and priming the pumps. These actions removed the licensee from the 24 hour LCO and placed Unit 2 into a seven day LCO until later that afternoon when an additional Unit 2 CCSW pump was returned to service.

(3) On September 11, 1989, a packing leak developed on the Unit 3 HPCI test return to Condensate Storage Tank valve during a surveillance test. Water spraying from the leak caused the valve torque switch to be submerged in water such that it did not function correctly. As a result, during the test the valve was driven into its seat and the valve motor was damaged. Valve packing and the valve motor were replaced.

(4) On September 15, 1989, during an instrument calibration surveillance, it was discovered that all four Unit 2 HPCI steamline pressure switches were out of calibration. These

switches were to provide a HPCI isolation at less than 80 psig to prevent low quality steam from entering and causing damage to the HPCI turbine. They were arranged in a one-out-of-two twice logic. These switches were all found to be actuating in the 40 to 50 psig range. However, the licensee considered the HPCI systems still able to meet the design function since this particular HPCI isolation signal was not addressed in Technical Specifications. HPCI isolation signals that were addressed dealt with sensing of a HPCI steam line break. The licensee also determined that this problem would not adversely affect the transient safety analysis. The licensee re-calibrated three of these switches but encountered difficulties with the fourth. It's actuation setpoint readjusted to 200 psig during the calibration and could not be changed. The licensee determined that a malfunctioning master trip card in a local panel required replacement. Prior to replacing the card, a half isolation signal was conservatively inserted to ensure that the full automatic isolation would remain functional during the card replacement. However, while removing the card a full HPCI isolation resulted. The licensee attributed the cause to inadvertent jarring of another card to the other isolation channel in the same panel as the malfunctioning card was removed. The HPCI isolation was reset and returned to normal standby lineup. The malfunctioning card was replaced and all HPCI steamline pressure switches were determined to be operable.

(5) On September 23, 1989, Unit 2 was placed into single loop operation when Recirculation Pump B was taken out of service. A noisy tachometer to Recirculation MG Set B was replaced. Single loop operation was in effect for approximately two hours. After restarting the idle recirculation pump, operators noted that the inner seal pressure for that pump was reading zero psig. However, the local indication was reading correctly at 1030 psig. A work request was initiated to investigate the problem.

(6) On September 24, 1989, a reactor building ventilation isolation and standby gas treatment system (SGTS) automatic start occurred. Reactor building ventilation radiation monitor 2B had previously been reading erratically and instrument maintenance personnel were preparing to investigate the problem when the monitor spiked high. This caused the Engineered Safety feature (ESF) actuation. Reactor building ventilation and the SGTS were left in that condition pending completion of troubleshooting of the monitor. The licensee found and replaced a bad cable connector to the monitor. Following a subsequent successful surveillance test on the monitor, reactor building ventilation and the SGTS were returned to normal.

(7) On October 9, 1989, the Unit 2 diesel generator was declared inoperable when it's output breaker failed to close during testing. The licensee found that secondary contacts in the

breaker cubicle were dirty which were subsequently cleaned. Further troubleshooting activities did not identify any other problems. The breaker was retested several times and operated satisfactorily. The Unit 2 diesel generator was declared operable on October 10, 1989.

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

Maintenance related activities continued to indicate a good approach to resolution of technical issues in regard to the area of root cause analysis of equipment failures. This was exemplified by the licensee's investigation of minor hydraulic oscillations of the Unit 2 HPCI turbine governor, which occurred during a HPCI overspeed trip test in the last Unit 2 outage as described in Paragraph 3 of this report. Although the HPCI turbine satisfactorily tripped on overspeed during the test, the identification of other abnormalities and the willingness to pursue corrective actions showed a genuine concern for proper functioning of equipment.

d. Response to NRC Initiatives During This Inspection Period

The inspectors noted that little progress was being made in the backlog of non-outage corrective maintenance work requests. As noted in Inspection Reports No. 50-237/89018; No. 50-249/89017, the inspectors had previously expressed concern regarding an excessive number of pending control room work requests and, as a result, the licensee had instituted appropriate corrective actions. In contrast, the number of non-outage corrective maintenance work requests had remained nearly constant since completion of the Unit 2 refueling outage in February 1989. No progress was evident toward approaching the better pre-refueling outage figures of the previous year. The inspectors also noted that little progress was being achieved regarding the number of pending work requests involving oil and water leaks. Comparison with the pre-refueling outage figures of the previous year also indicated an overall negative trend. Finally, the number of problem analysis data sheets remaining open had steadily increased during the last year with very few being completed. The inspectors expressed concerns to licensee management regarding maintenance trends which correlate to material condition of the plant. At the end of the inspection period, the licensee provided recent data that indicated a substantial decrease in the number of pending non-outage corrective work requests during the previous two months. These numbers were closely approaching those existing prior to the last refueling outage. The licensee attributed this decrease to the ability to assign additional personnel to the backlog who had previously been busy with the Unit 3 transformer outage and preparing for the Security regulatory effectiveness review earlier in the year. In general, this is considered to be good response to NRC initiatives.

c. 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 limiting conditions for operation 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:

- Reactor Building Ventilation Radiation Monitor Linearity Check

- Fuel Assembly Inspection (Exxon Fuel)

6. Safety Assessment/Quality Verification 35502 and 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

The inspectors observed the monthly performance review meeting conducted on September 12, 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 recurring control room alarms, degraded or out of service equipment and potentially significant events. In addition, the status of the top technical issues and performance review action items were discussed. The inspectors found this meeting to emphasize the sharing of information between plant departments on these issues and allowed management to expedite resolution to items requiring specific action. As such, the inspectors viewed it as a beneficial management tool toward efficient and safe plant operation.

7. Engineering/Technical Support (37828)

a. Enforcement History

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

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

The licensee's approach to LPCI outboard injection valve, 2-1501-21B, stem to plunger separation diagnosis (as described in Paragraph 3 of this report) was mixed. While it was commendable that the licensee was diligent in eventually identifying the correct cause of a difficult to diagnose problem, several management breakdowns hindered the progress of this diagnosis. These are discussed as follows:

- The knowledge and training of technical staff engineers was deficient in regard to analysis of motor operated valve test data. A noticeable decrease in the running current of the valve from current traces taken on February 10, 1987, and December 18, 1988, did not cause further analysis for possible problems. In addition, valve stroke times obtained on February 1, 1989, showed a marked increase from the previous operating cycle. The difference in the valve stroke times were attributed to replacement of the actuator's phenolic limit switch blocks. However, changing the limit switch block without resetting the limit would not change the stroke time of the valve. Thus, data was available prior to the August 7, 1989, surveillance test failure which indicated a possible need for additional study, but was not identified as such by the engineers.

- Involvement of the technical staff engineers in problem analysis was inadequate. Current signatures taken on the valve on August 17, 1989, were reviewed by electrical maintenance department personnel without involvement of the MOV coordinator. Based on this review and previous surveillance test results, the Unit 2 diesel generator was taken out of service. However, this review didn't compare the trace to previous traces which would have identified a problem. Instead, the LPCI A and B valve results were compared and the difference attributed to a known problem with the A valve. MOV coordinator involvement, which eventually led to diagnosis of the problem, was an individual decision and not a normal program practice.

- Ineffective communications resulted in personnel not being adequately informed of all pertinent information on which to judge valve operability. The Operating Engineer who determined operability was not aware of the flow differences in the surveillance test data obtained on August 17, 1989. In addition, he was not aware of changes in the running current and stroke times. Thus, the decision was made with insufficient information.

It was fortuitous that the problem was eventually diagnosed at all in that the final diagnosis was not the result of any formal program that could be consistently relied upon. Instead, diagnosis was due to an overall philosophy stressing quality operations which, in this case kept individuals searching for a root cause. Further review of the valve design following the event showed that the type of separation that occurred just caused the valve to operate as a check valve and did not in fact, render the system inoperable. The valve design and the orientation of the valve in the piping was also fortuitous in that the system was still technically operable and thus rendering the Unit 2 diesel generator inoperable at the same time did not seriously jeopardize the safety status of the facility.

However, due to the programmatic problems cited above, the licensee identified the following corrective actions:

- Provide motor operated valve actuator training for the IST valve timing reviewer and appropriate system engineers to assist them in determining root causes of the actuator timing discrepancies.
- Change Dresden Maintenance Procedure (DMP) 040-6, Safety-Related Motor Operated Valves Data and Setting, to add a review by the MOV coordinator verifying the current trace taken is reviewed and compared to the previous trace if available.
- Conduct training sessions by the Operations Department and the Technical Staff to emphasize the importance of effective and timely communication of surveillance test data results and to clarify the Technical Staff system engineers' role in problem solving analysis.

Additional actions planned by the licensee specific to this event included disassembly of the 2-1501-21A valve actuator to repair the worn worm gear during the next refueling outage. Furthermore, a metallurgical analysis on the fractured stem was planned to determine the failure mechanism and thus to determine whether other valves of this type may be accessible to similar failure.

Licensee actions taken to determine the cause of elevated Unit 2 HPCI room ambient temperatures, as described in Paragraph 3 of this report, represented an excellent approach to root cause analysis. The conduct of a heat load analysis on the HPCI room was indicative of a desire to solve repeated problems.

c. Assurance of Quality, Including Management Involvement and Control

Management involvement in identifying and developing corrective actions in this functional area was particularly evident. Various management breakdowns which became apparent as a result of the LPCI outboard injection valve problem diagnosis were aggressively pursued by the licensee. However, continued licensee management attention was needed to ensure proper implementation of a system engineer concept.

8. Emergency Preparedness (93702)

a. Enforcement History

During this inspection period no violations or deviations were identified in the emergency preparedness functional area.

b. Operational Events

On September 24, 1989, with Unit 2 at 70 percent power and Unit 3 at 98 percent power, an unusual event was declared when two nearby offsite telephone cables were severed by individuals digging post holes for a fence installation. As a result, commercial, Emergency Notification System and Nuclear Accident Reporting System telephone service was rendered inoperable. Appropriate notifications were made by use of the company microwave system through the Chicago load dispatcher. In addition, a portable cellular telephone was obtained to supplement offsite communications. Complete telephone service was restored and the unusual event terminated later that same day.

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

The licensee's response to loss of telephone communications on September 24, 1989, indicated a high priority for emergency preparedness. Despite the problem, operations personnel quickly assessed the situation, recognized the importance of reporting requirements and completed the notifications within 15 minutes.

9. Systematic Evaluation Program (SEP) (92701)

The inspectors reviewed the following SEP items for implementation per NUREG-0823 criteria and licensee commitments. Of the original 12 SEP items assigned for inspection on Dresden Unit 2, the following six were considered to be open at the start of this inspection period. Listed below is the current status associated with these items:

4.1.4 Revision of Emergency Plan to Cope With Design Basis Flooding. (No. 237/89019-03(DRP))

The licensee revised the Flood Emergency Plan (Emergency Plan Implementing Procedure (EPIP) 200-11) to meet the criteria of NUREG-0823 as documented in inspection report No. 237/85030. However, a commitment (as documented in Inspection Reports No. 237/83032 and No. 237/85030) was made to either install a canal intake level monitor or the means to indicate heavy precipitation to alert the load dispatcher of the potential of flooding above the 507 foot elevation. Initially, the licensee developed a modification (M12-2/3-83-001) to install river level indicators by the control room, but it was not approved and subsequently cancelled. A new modification request was developed on March 2, 1989, to provide a river water level indication and alarm within the control room. The modification is scheduled to be installed by mid 1990. This topic is considered closed. However, the installation and testing of the river level indication and alarm in the control room is considered to be an open item (No. 237/89019-04(DRP)).

4.18.1 Review Containment Penetrations and Provide Locking Devices and Administrative Controls as Necessary. (No. 237/89019-05(DRP))

An interim inspection of this topic was conducted as documented in Inspection Report No. 237/83032. This interim inspection verified that the required review of locked valves had been completed and administrative controls (procedures) had been revised to include the required valves. This topic was considered to be open during the interim inspection because the the locking devises had not been installed. Subsequent to the inspection, all valves required by this topic were locked on March 6, 1984. This topic is considered to be closed.

4.18.3 Lock Identified Manual Isolation Valves and Modify Associated Procedures. (No. 237/89019-06(DRP))

This topic was considered to be open during an interim inspection (documented in Inspection Report No. 237/83032) since valves 4327-500, 4327-502 and 1916-500 had not been locked closed or added to the locked valve control procedure. Subsequently, manual isolation valves 4327-500, 4327-502, 1916-500 and 4609-501 were verified locked and included in locked valve checklists DOP 404-M1, M2 and M3. This topic is considered to be closed.

4.21.2 Provide Procedures to Assure Disconnect Links Are Properly Positioned Following Maintenance. (No. 237/89019-07(DRP))

This topic was considered to be open during an interim inspection (documented in inspection report No. 237/83032) since procedures had not been implemented to control disconnect links. Dresden Operating Procedure (DOP) 6900-E2 was revised (Revision 7) in June 1987 to include requirements for verification of electrical disconnect links after completion of maintenance on the associated busses. Additionally, the licensee's actions associated with this topic was determined to be acceptable per letter from Daniel R. Muller, Director Project Directorate III-2 (NRR) to L. D. Butterfield, Jr. (CECo) dated October 14, 1987. This topic is considered to be closed.

4.26.2 Bypass of Diesel Generator Underfrequency Protective Trips During Emergency Operations. (No. 237/89019-08(DRP))

This topic was considered to be open during an interim inspection (documented in inspection report No. 237/83032) in that modifications (M12-2-82-38 for Unit 2 diesel generator, M12-3-82-38 for Unit 3 diesel generator and M12-2/3-82-38 for Unit 2/3 diesel generator) were developed and considered acceptable. However, these modifications were not completed prior to the completion of the interim inspection. A second interim inspection (documented in Inspection Report No. 237/85030) verified that two of the three modifications

(M12-2-82-38 and M12-3-82-38) had been completed. Subsequently, the third modification (M12-2/3-82-38) was completed on September 15, 1986. This topic is considered to be closed.

4.28 Provide Monitoring of D. C. System in Control Room. (No. 237/89019-09(DRP))

The licensee committed to provide battery voltage indication in the control room per letter dated October 5, 1982. Two interim inspections (as documented in Inspection Reports No. 237/83032 and No. 237/85030) were conducted and considered this topic to be open based on the requirements of this topic being accomplished through the plant modification process. The October 5, 1982, commitment provided for indications of battery voltage, battery current, battery charger output current, battery breaker indication and battery charger breaker indication in the control room for the 125/250 and 24/48 VDC batteries. The indication of battery voltage for the 125v, 250v and 24/48v batteries were accomplished by modifications M12-2(3)-81-28, M12-2(3)-81-29 and M12-2(3)-82-3. However, the licensee requested a change to their October 5, 1987 commitment in a letter dated August 11, 1987. The change requested the deletion of the requirements to monitor battery currents and battery/charger breaker status. The bases of the request concluded that the normal maintenance surveillances, installed high discharge current/low voltage alarm (per modifications M12-2(3)-83-6 on the 125v and 250v systems) and the battery voltage indication provided in the control room would alert operators to upsetting battery conditions on the safety related batteries. The August 11, 1987 change request also committed to provide a high discharge current/low voltage alarm for the 24/48v system per modifications M12-2(3)-87-58. These modifications are scheduled to be completed on Unit 2 during the December 1990 refueling outage and on Unit 3 during the March 1991 refueling outage. These change requests were reviewed and accepted per the Safety Evaluation Report (SER) dated June 27, 1988 (Subject: IPSAR Topic VIII-3.B, DC Power Systems Bus Voltage Monitoring and Annunciating (TAC 66029)). This topic is considered closed since the current Unit 2 and Unit 3 monitoring scheme meets the SER.

No violations or deviations were identified in this area.

10. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for August. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

11. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. An open item disclosed during the inspection is discussed in Paragraph 9.

12. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on October 10, 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.