U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/91022(DRP); 50-249/91022(DRP)

Docket Nos. 50-237; 50-249 License Nos. DPR-19; DPR-25

Licensee: Commonwealth Edison Company

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

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: June 29 through August 22, 1991

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9/11/91
Date

Inspection Summary

Inspection from June 29 through August 22, 1991 (Report Nos. 50-237/91022 (DRP); 50-249/91022(DRP)).

Areas Inspected: Routine unannounced safety inspection by the resident inspectors, region based inspectors, and an Illinois Department of Nuclear Safety inspector of licensee action on previously identified items; licensee event reports; operational safety; monthly maintenance; monthly surveillance; training effectiveness; Systematic Evaluation Program items; events; safety assessment and quality verification; and report review.

Results: Three cited violations were identified. One involved the failure of maintenance workers and their supervision to follow written procedures during the installation of the steam separator within the reactor vessel. Another involved inadequate corrective actions to a previous violation in the area of NRC reporting. The third violation dealt with programmatic inadequacies of the channel check process. One non-cited violation was identified involving use of an inadequate procedure by operators while performing radwaste transfer activities. Five unresolved items and two open items were identified. One Systematic Evaluation Program item was closed. This was Item 14 - Topic III-4.5.3 and 2.2.2 (Supp. 1).

## Plant Operations

Management decisions with regard to power ascension and shutdown were conservative. Operator performance during abnormal and transient conditions was good. Some weaknesses were noted in the management directives for operations regarding NRC reporting, flow control line (FCL) control rod manipulation instructions, and actions for safety related 4160 VAC bus low voltage conditions. Also, operators failed to stop and receive additional instructions on two occasions (FCL situation and radwaste transfer activities) with adverse consequences. Finally, management exhibited a significant increase in awareness towards reporting plant events to the NRC.

## Maintenance/Surveillance

Findings associated with the steam separator shroud installation were reflective of personnel performance weaknesses during the last Unit 2 refueling outage 10 months ago. Maintenance actions during this inspection period appeared adequate except in the reactor recirculation discharge valve initial root cause determination. Weaknesses in the content of the surveillance program persisted and expanded from the previous inspection report period.

## Safety Assessment and Quality Verification

A strength was noted in the reviews conducted by Offsite Review Safety Group with their findings considered relevant and a worthwhile contribution to safe operation. Nuclear Quality Program audits were performance based and beneficial in identifying problems. The commitment tracking program for licensee event report (LER) corrective actions appeared to be adequate. Conversely, some weaknesses were noted in the scope of safety evaluations being reviewed by the offsite review group and in the quality of the post scram review report for June 9, 1991.

## DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Technical Superintendent
*J. Kotowski, Production Superintendent
E. Mantel, Services Director
D. Van Pelt, Assistant Superintendent - Maintenance
J. Achterberg, Assistant Superintendent - Work Planning
*G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
R. Stobert, Operating Engineer
T. Mohr, Operating Engineer
*M. Strait, Technical Staff Supervisor
L. Cartwright, Q.C. Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*B. Viehl, Engineering and Construction
*F. Kanwischer, Services Superintendent
T. Mohr, Operating Engineer
*K. Kociuba, Quality Assurance Superintendent
*D. Lowenstein, Regulatory Assurance Analyst

*Denotes those attending the exit interview conducted on August 22, 1991, and at other times throughout the inspection period.

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 maintenance personnel, and contract security personnel.

2. Previously Identified Inspection Items (92701 and 92702)

(Open) Open Item (50-237/90027-14(DRP)): Perform sample inspection of Systematic Evaluation Program (SEP) topic resolutions. An additional SEP item confirmed completed by the inspectors is listed in paragraph 8. This open item will remain open pending completion of licensee confirmation of topic closures and completion of the NRC sample inspection.

(Closed) Violation (50-237/91003-01(DRP)): The failure of Dresden Instrument Surveillance (DIS) 500-9 to adequately prescribe steps to measure the Reactor Protection System response time in accordance with Technical Specification requirements. The inspector reviewed the

licensee's planned corrective action including revision of DIS 500-9 to ensure the proper applications of test equipment. The inspector determined that removal of Dobler timer and the addition of detailed procedures are contained in the revised DIS 500-09. This item is closed.

(Closed) Unresolved Item (50-237/91009-04(DRP)): Evaluate causal factors for the March 22, 1991, event involving the lifting of the steam separator assembly on Unit 2. On March 22, 1991, Dresden Unit 2 experienced an unexpected anomaly in electrical power as core flow was increased. As coolant flow through the reactor core increased from 72 to 75 million pounds per hour, the plant's electrical output increased by 2 megawatts instead of the anticipated 30 megawatt increase. Also, reactor coolant temperature in the annulus region increased about 2 degrees Fahrenheit at the same time the core flow/electrical output anomaly occurred. Because the power/flow anomalies were similar to a Vermont Yankee event associated with the steam separator lifting from the seat on the core shroud in the reactor, the licensee commenced a Unit 2 shutdown on March 24, 1991, to inspect the reactor internals. An investigation team comprised of CECo corporate and plant individuals was formed to review this event, along with other recent maintenance-related problems which occurred during the Unit 2 refuel outage. On March 27, 1991, NRC regional specialists arrived on site to review the event and licensee actions.

On March 27, 1991, the steam dryer was removed to facilitate the inspection of the shroud head bolts. With assistance from General Electric Company (GE), a detailed inspection plan was initiated and implemented, with emphasis placed on verifying if the shroud head bolts were latched and tightened. Troubleshooting and corrective actions were performed under work request D00524. Visual inspections on seven accessible shroud head bolts with an underwater camera indicated that the bolts were latched, but not tightened. Subsequently, all 48 bolts were verified latched, but not tightened. In addition, several spring retainers were found to be mis-positioned. Based on an evaluation performed by GE, the loose shroud head bolts would allow the shroud head and steam separator to lift at high core flow conditions. The GE analysis for the Vermont Yankee event concluded that no significant changes in plant safety margins occurred during operation with the steam separator assembly lifted.

The following conclusions were based on interviews, observations, and document reviews, conducted by NRC regional inspectors on March 27 - July 16, 1991:

Steam separator installation was completed during the Unit 2 refueling outage on November 26, 1990, using Work Request D94963 and Dresden Maintenance Procedure (DMP) 0200-12, "Reactor Shroud Head and Steam Separator Installation," Revision 7. A second shift mechanical maintenance crew completed the steam separator installation in the reactor cavity, and a third shift crew (3 maintenance mechanics) completed the latching and tightening of the separator shroud hold down bolts. Based on the signed steps, in the work package (Steps G.12 and G.15), the third shift foreman verified the hold down bolts were locked (latched), signed that the hold down bolt nuts were tightened, independently verified the hold down bolt

nuts were tight, and signed that all spring retainers were correctly positioned up on the nut.

The work crew did not use the procedure while performing the shroud head bolt work. All three mechanics and the foreman indicated that they did not recall seeing the work package during the shift. Workers were not familiar with having the procedure at the actual job location because work practices on the refuel floor for mechanical maintenance allowed the use of a "clean" table for the administrative aspects (signing of steps) of the work. This table was located on the refuel floor; however, away from the work performed on the refuel bridge. Review of the procedure by the NRC and the licensee indicated that the procedure, although weak, was adequate and should have resulted in shroud head bolt tightness. Failure to follow DMP 0200-12 for steam separator shroud bolt locking and tightening is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-237/91022-01a(DRS)).

There was no apparent management involvement during the third shift mechanical maintenance activities on November 26, 1990. Because of a shortage of foremen for that shift, one regular foreman and one upgraded mechanic were assigned supervisor coverage of the shift's activities. Normally, three foreman were utilized. Inadequate shift coverage was not communicated to management. This lack of supervision resulted in little observation of maintenance activities on the refuel floor. Although the assigned foreman signed the procedure step for tightening the hold down bolts, he did not observe the work. The foreman was assigned 5 jobs for coverage during the shift, with most of his time spent supervising critical path work performed on the Main Steam Isolation Valves. Dresden Administrative Procedure (DAP) 9-11, "Procedure Usage and Adherence," Revision 2, Step 0.(3) stated that when a step was initialed or signed, it must be based on either direct observation, or a direct report such as face to face communication. If other than direct observation was utilized, then the initials of the person performing the observation must be included with the initials of the person actually initialing the step. Failure to observe the work or to have any or the three mechanical maintenance crew members initial the step for the performance of the tightening of the hold down bolts is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-237/91022-01b(DRS)).

All three mechanics had no experience in the hold down bolt tightening, the proper use of the bolt wrench, or the bolting mechanism. The lead mechanic recalled experience only with the removal of the separator. The licensee provided no formal training on this bolting process. Training, usually consisted of "passed down" training from experienced crews. The foreman had received informal training as a junior foreman observing the previous Unit 3 separator installation, but had never actually performed the work.

Independent verification was not clearly understood by the foreman. The cause of this power/flow anomaly clearly indicated that the bolts were not tightened, or independently verified as tight. After work had been completed, the lead mechanic and the foreman went to the bridge and the foreman "independently verified" the bolt tightness with an underwater

telescope. The tops of the bolts have two flats machined into them. The area between the two flats indicated the position of the locking (latching) T-lugs on the bottom of the bolt assembly. The foreman incorrectly used this indication and verified the bolts to be tight. Bolt tightness could not have been verified in this manner, since the area in question was located under the shroud lugs. DAP 9-11, "Procedure Usage and Adherence," Revision 2, defined independent verification as the certification of the correctness of an operation or condition based on either first-hand observation or through personally performed manipulation. Failure to adequately perform the independent verification of the shroud head bolt tightness in accordance with DAP 9-11 is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-237/91022-01c(DRS)).

The foreman also initialed the procedure step that stated that all spring retainers were correctly positioned up to capture the hold down bolt nuts. The foreman indicated to both the NRC and the licensee that he did not know how to actually verify the correct position of the spring retainers. His visual verification was based on the fact that the spring retainers did not appear to be broken and nothing was out of place.

The unresolved issue regarding this event is closed; however, one violation with three examples and no deviations were identified in this area.

3. Licensee Event Reports Followup (90712 and 92700)

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

(Closed) LER 249/91-004 "Unplanned Standby Gas Treatment System Auto-start During Calibration".

(Closed) LER 249/91-003, "Inoperable Torus Wide Range Lever Transmitters Due to Unknown Cause".

In addition to the foregoing, the inspector reviewed the licensee's Deviation reports (DVRs) generated during the inspection period. This was done in an effort to monitor the conditions related to plant or personnel performance, potential trends, etc. DVRs were also reviewed for initiation and disposition as required by applicable procedures and the quality assurance manual.

No violations or deviations were identified except as delineated in this or other reports.

4. Operational Safety Verification (71707)

During the inspection period the inspectors verified daily, and randomly during back shift and on weekends, that the facility was being operated

in conformance with the license and regulatory requirements and that the licensee's management control system was effectively carrying out its responsibilities for safe operation. This was done on a sampling basis through routine direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, reviews of operating logs, independent verification of safety system status and limiting conditions for operation action requirements (LCOs), corrective action, and review of facility records.

On a sampling basis the inspectors daily verified proper control room staffing and access, operator behavior, and coordination of plant activities with ongoing control room operations; verified operator adherence with the latest revisions of procedures for ongoing activities; verified operation as required by Technical Specifications; including compliance with LCOs, with emphasis on engineered safety features (ESF) and ESF electrical alignment and valve positions; monitored instrumentation recorder traces and duplicate channels for abnormalities; verified status of various lit annunciators for operator understanding, off-normal condition, and corrective actions being taken; examined nuclear instrumentation and other protection channels for proper operability; reviewed radiation monitors and stack monitors for abnormal conditions; verified that onsite and offsite power was available as required; observed the frequency of plant/control room visits by the station manager, superintendents, assistant superintendents, and other managers; and observed the Safety Parameter Display System for operability.

Items for consideration during plant tours included radiological controls adherence, security plan implementation, housekeeping controls and component leakage/lubrication. As a result of these tours and reviews these specific occurrences were evaluated:

a. Torus Wide Range Level Transmitter 3-1641-5B drifted from 14.7 feet to 13.5 feet between January 31, 1991, and February 2, 1991. A similar drop on 3-1641-5A occurred between April 6, 1991, and May 31, 1991. Operators did not identify these failures until June 5, 1991, although the Unit Operator Daily Surveillance Log (DSL) (Appendix A) required performance of a daily instrument check on these instruments.

   By Technical Specifications definition, "an instrument check is a qualitative determination of acceptable operability by observation of instrument behavior during operation. This determination shall include, where possible, comparison of the instrument with other independent instruments measuring the same variable". Initial operator training included only the Technical Specifications definition and on-the-job training for Appendix A completion from licensed Nuclear Station Operators (NSO).

   Specific training involving accuracy for specific instruments in regard to operability determination had not been given. Although most of the NSOs appeared to be knowledgeable of the correlation between the narrow range torus level indicator and the two wide

range level indicators, i.e. 0" on the narrow range indication corresponds to 15'-0" on the wide range indications, they did not necessarily use this correlation to perform the operability check. The Unit Operator DSL (Appendix A) did not provide tolerances, thus making it difficult for the NSO to assess instrument operability by means of an instrument check. NSOs also stated that additional procedural guidance would be beneficial for performing instrument checks.

The failure of instruction, procedures, or the Unit Operator DSL (Appendix A) to provide appropriate acceptance criteria for performing the instrument check is a violation (50-249/91022-02(DRP)) of 10 CFR 50, Appendix B, Criterion V. In addition, several operators indicated that they would question the operability of these instruments and take appropriate action if they were indicating at least one foot below the normal expected level of 14.7 feet. However, the one foot drift did occur and went unidentified for an extended period.

b. During the performance of Dresden Operating Surveillance (DOS) 1400-04, "Cold Shutdown Testing of the Core Spray System Check Valves", on July 11, 1991, the 2B core spray pump ran without a suction source for a short period due to the condensate storage tank suction valve, 2-1501-37, being in it's normally locked closed position. Although high vibration was observed, no pump damage was identified before the pump was stopped. The failure to open this valve prior to performing the surveillance was due to a deficiency in DOS 1400-04 that did not prescribe opening the valve. In addition, the applicable piping and instrument drawing M-35, Sheet 1, indicated the normal position of this valve as locked open. Deficiencies regarding the procedure and drawing are considered an unresolved item (50-237/91022-03(DRP)) pending a review to determine whether drawing discrepancy was isolated and whether this procedure had been revised under the procedure upgrade program.

c. On July 23, 1991, Unit 2 control rods were inserted to reduce the flow control line (FCL). The Control Rod Sequence (CRS) for shutdown enforced by the rod worth minimizer (RWM), did not correspond to the first step provided in the FCL instructions. Therefore, to use the FCL instructions entailed bypassing the RWM. Previous management direction had indicated that the RWM would be left inservice, even at high power levels. Upon weighing the conflicting directives, the Shift Control Room Engineer (SCRE) incorrectly instructed the NSO to follow the CRS, resulting in the insertion of four shaper control rods from step 48 to step 40. However, the SCRE and NSO did not recognize the possible power shaping/fuel integrity problems associated with inserting rods per CRS without first reducing recirculation flow as prescribed in the shutdown procedure. The on-call Qualified Nuclear Engineer (QNE) was not consulted by the operating crew. Upon inspection the following morning, a QNE noted the unexpected rod pattern.

Subsequent analysis by the QNE indicated that in this particular case, power shaping/preconditioning envelope problems did not result. The operator training program did not specifically address the importance and possible adverse reactions to not following the FCL instructions. The day before the event, a licensee initiated reactivity assessment team had identified this particular weakness and the ramifications. This is considered an unresolved item (50-237/91022-04(DRP)) pending review of the documentation of a licensee reactivity assessment completed just prior to this event.

d. On July 23, 1991, large areas of the Unit 2 and Unit 3 reactor buildings became contaminated, primarily with Co-60, Mn-54, and Fe-59, at a maximum of 150,000 disintegrations per minute/100 cm2. The contamination was identified after four workers, who had completed the transfer of spent resin from the Unit 2 fuel pool demineralizer to a tank in the radwaste building, alarmed the personnel contamination monitors at the main access point to the turbine building. Contamination was mainly on their shoes. Minor contamination was also found in the turbine building along the path the workers took after exiting the Unit 2 reactor building. Access to the reactor buildings was restricted during the subsequent cleanup activities. In addition, an investigation team was formed by the licensee to determine the cause of the contamination. Whole-body counts of personnel who were in the reactor buildings at the time of the resin transfer identified only one worker with detectable internal contamination. The whole-body count for this individual, who was involved in the transfer, identified the presence of 7 nanocuries of Co-60, a level indicating an exposure to airborne radioactivity well below regulatory limits.

The licensee's investigation indicated that the fuel pool demineralizer had not been vented properly prior to backflushing the resin transfer line after the resin transfer was completed. Air pressure from the demineralizer vented via the demineralizer's freeboard drain line and expelled contamination out of a sample sink drain line, which drained to a common drain line utilized by the demineralizer. Spread of contamination from the sample sink drain to the two reactor buildings was exacerbated because the normal reactor building ventilation was secured and the lower volume standby gas treatment system was in operation at the time.

The licensee stated that a similar resin transfer and backflushing had been done quarterly for several years without similar problems, but that this time the auxiliary operator did not vent the demineralizer to atmospheric pressure as had been done in the past. The procedure used to transfer resin and backflush, Dresden Operating Procedure (DOP) 1900-8, Revision 2, "Fuel Pool Demineralizer Resin Transfer," did not contain specific instructions for venting the demineralizer prior to backflushing. The licensee indicated that the procedure will be revised to include this information. In addition, the licensee indicated that the revised procedure would prohibit transfers during standby gas treatment

operation and that the drain line on the sample sink, which was not in use, would be sealed. The failure of DOP 1900-8 to adequately prescribe steps to vent the demineralizer prior to backflushing is considered to be a violation (50-237/91022-05(DRSS)) of 10 CFR 50, Appendix B, Criterion V; however, in accordance with 10 CFR 2, Appendix C, Section V.A., a Notice of Violation is not being issued. The procedure revisions and modifications to the sink drain line will be reviewed during a future inspection and is an open item (50-237/91022-06(DRSS)).

During the review of this incident by the NRC radiation specialist, several minor problems were noted with the control of access to the contaminated reactor buildings, Although a "contaminated area" sign was posted at the double step-off-pad area set up in the narrow hallway leading into the Unit 2 reactor building, it was not readily visible. Also survey maps had not been updated by the start of the day work shift on July 24, 1991, to indicate the change in contamination levels in the reactor buildings. One individual entering the reactor building during the day shift on July 24, 1991, received low level shoe contamination when the step-off-pads were crossed without recognizing the need for protective clothing. These matters were discussed with the licensee who agreed to develop a checklist for use in future contamination events to ensure that all access control measures are established promptly and adequately. This checklist will be reviewed during a future inspection and is an open item (50-237/91022-07(DRSS)).

One cited violation, one non-cited violation and no deviations were identified in this area.

5. Monthly Maintenance Observation (62703)

Station maintenance activities affecting the safety-related systems and components listed below were observed/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 Limiting Conditions for Operation 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.

The inspectors monitored the licensee's work in progress and verified that it was being performed in accordance with proper procedures, and approved work packages, that applicable drawing updates were made and/or planned, and that operator training was conducted in a reasonable period of time.

The following maintenance activities were observed and reviewed:

Unit 2
Recirculation System Sample Valve 220-44 Repair
Shutdown Cooling Loop 2A Suction Valve Control Circuitry Repair
Unit 2B Shutdown Cooling Pump Discharge Isolation Valve and Logic Repair
Unit 2B Instrument Air Compressor Overhaul

Unit 3
Unit 3A/3B Hydrogen/Oxygen Monitor Repair
3A Core Spray (CS) Pump Maintenance
3A CS Isolation Valve Rotor Modifications
3A CS Valve Breaker Maintenance
3A & B Post-LOCA Hydrogen/Oxygen Monitor Repair

On August 6, 1991, the Nuclear Station Operator (NSO) observed the 2A reactor recirculation pump indicated speed increase to 100%. While the operator was manually reducing pump flow, the 2A pump motor tripped and locked out as result of over excitation. Following the pump trip, the CRAM arrays were inserted to exit from the power/flow instability region. Investigation determined the pump trip was the result of a failed resistor in the recirculation motor generator voltage regulator circuit. In attempting to close the pump discharge valve 2-202-5A to facilitate returning the idle loop to service, the valve failed to close until the electrical contactors, at the breaker cubical, were manually held in. A drywell entry was made to facilitate a temporary alteration to bypass the large loading conditions encountered by the valve during a portion of the closing cycle such that the valve could perform its design function. Further engineering review indicated that the valve torque switch setting was incorrect and another drywell entry was made to change the setting. The incorrect setting resulted from valve operation test and evaluation system (VOTES) testing problems encountered on the valve during the previous refueling outage. This is considered an unresolved item (50-237/91022-08(DRS)) pending further review of the adequacy of previous VOTES testing and the resulting torque switch setting.

No violations or deviations were identified.

6. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications during the inspection period 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 results

conformed with Technical Specifications and procedure requirements 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:

Unit 2
DOS 2300-1, "HPCI Motor-Operated Valve Operability Verification"
DOS 2300-3, "HPCI System Operability Verification"
DOS 6600-2, "Unit 2 Diesel Generator Monthly Operability Test"

Unit 3
DOS 500-3, "APRM Rod Block and Scram Functional Test"
DOS 5600-2, "Monthly and Weekly Turbine Checks"

The following items were evaluated:

a. Technical Specification Surveillance 4.7.C.a requires the secondary containment integrity be demonstrated by drawing a 1/4 inch vacuum with the standby gas treatment system at each refueling outage. During surveillance testing, the secondary containment integrity acceptance criteria was verified by the averaging of four differential pressure (DP) indicators located at the refuel floor. The inspector identified the calibration of these DP instruments (DPI-2/3-5741-517, -518, -519 and -520) was performed without an approved procedure or specified acceptance criteria. However, the inspectors noted that this could be considered another example of a recent violation (50-237/91016-02(DRP)) and therefore, may be encompassed by the corrective action regarding that violation. Subsequent review of the violation response identified that the response was not broad enough. This was discussed in the NRC response to the licensee's corrective actions and will be pursued following resolution of the previous violation.

b. On July 8, 1991, an automatic standby gas treatment system start and reactor building ventilation system isolation inadvertently occurred during a surveillance on the isolation condenser area radiation monitor. Upon identifying the correct cable for the radiation monitor power supply inside a main control room panel, the instrument technician laid down the procedure. Upon turning back to the panel, the technician inadvertently disconnected the cable for the reactor building fuel pool channel "A" process radiation monitor power supply in the same location in the adjacent panel section. This caused the engineered safety features actuation and was of no safety consequence. The technician appeared knowledgeable of the procedure and had a momentary lapse of attention to detail and self-checking. The instrument technician was counseled and this event was reviewed with instrument maintenance department personnel. The licensee reviewed component labeling and determined this not to be a contributing cause.

The inspector noted that the individual involved was not listed on the job assignment matrix for this task. The inspector did not, however, consider this a contributing factor to the event. The technician had been trained for the task but had not received an on-the-job training evaluation. This was in accordance with a maintenance department memorandum that allows this if the technician works under the direct supervision of the supervisor. The memorandum defined direct supervision as observing the critical work steps as defined by the supervisor. In this case, no critical steps were designated due to the supervisor's belief that none existed in this procedure. (Only monitors with an alarm and no automatic actuation function were covered by this procedure.) The licensee indicated that a specific definition of critical steps had not been given in order to give the supervisor more latitude based upon personnel knowledge of the technician's abilities. However, the licensee did subsequently issue Instrument Department Memorandum 8, which formalized the determination of critical steps to ensure that both technician and supervisor were agreed on critical step identification prior to work performance. Therefore, the inspector has no further concerns in this area.

c. On August 12, 1990, the licensee identified deficiencies in Dresden Instrument Surveillance (DIS) 700-4, "Intermediate Range Monitor (IRM) Rod Block/Scram Calibration Test", Revision 7, in that the IRM Hi-Hi and INOP functions were not tested adequately to meet Technical Specification Table 4.1.1 requirements. Due to the IRM Hi-Hi Scram Signal being bypassed when the mode switch was in RUN and reactor power greater than five percent, the actuation circuitry was not tested all the way to the scram (107) relays when in this condition. In addition, the procedure required the IRM being tested to be bypassed such that the circuitry would also not be tested to the scram (107) relays. (This was not an immediate safety concern since these scram functions were automatically bypassed at the power conditions the units were in at the time of discovery.) The licensee later discovered similar problems with the source range monitors. The licensee planned to properly test these functions as soon as appropriate conditions were reached. This is considered an unresolved item (50-237/91022-09(DRP)) pending review of the test results when the circuits are properly tested and, an understanding of how this problem was originally discovered.

No violations or deviations were identified.

7. Training Effectiveness (41400, 41701)

The effectiveness of training programs for licensed and non-licensed personnel was reviewed by the inspectors during the witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during the review of the licensee's response to events which occurred during the inspection period. Except as indicated in paragraph 4.c, personnel appeared to be knowledgeable of the tasks being performed, and nothing was observed which indicated any ineffectiveness of training.

No violations or deviations were identified except as indicated in paragraph 4.c.

8. Systematic Evaluation Program (SEP) Items (92701)

NUREG 1403, "Safety Evaluation Report Related to the Full-term Operating License for Dresden Nuclear Power Station, "Table 2.1, identified 22 SEP Integrated Plant Safety Assessment Report topic resolutions to be confirmed by the NRC Region III office.

The following item in that report was confirmed as closed by the inspectors:

Item 14 - Topic III-4.5.3 and 2.2.2 (Supp. 1)

The completion for Item 2 for Topic II-3.b.1/4.1.4 is being tracked as Open Item 50-237/89019-04. In addition to Item 2, the following two items remain to be verified as closed by the licensee and confirmed by the NRC.

Item 13 - Topic III-2/2.2.2 (Supp. 1)
Item 16 - Topic VI-4/4.18.2; Topic VI-6/4.19

Each of these items was in some stage of verification review by the licensee.

9. Events Followup (93702)

a. On July 10, 1991, radiation protection personnel discovered a steam leak in the reactor water cleanup heat exchanger room in a reactor recirculation sample line. Closure of the recirculation sample line containment isolation valves (2-220-44 and 45) failed to stop the leakage. The leakage path was subsequently isolated by the closure of a down stream manual valve. An Unusual Event was declared as Unit 2 was shutdown due to the containment isolation valve leakage. The sample line containment isolation valves had previously failed on March 4, 1990, and February 21, 1991. The unit was restarted on July 14, 1991, following repair of the sample line containment isolation valves. As-found leakage testing following the shutdown determined that the total type B and C leakage did not exceed Technical Specification limits. The vast majority of the leakage was from the inboard (44) valve due to galling along the seating surface of the valve plug and seat. The licensee believed the galling was caused by maintenance activities while setting the stem travel or adjusting the valve to reduce its leakage. Post-maintenance local leak rate testing did not identify the excessive leakage since leakage changed with the variation in seating from one closure to another, depending upon how the galled imperfections happened to align. Following lapping of the valve seat and machining of the valve plug, special care was taken during valve reassembly to avoid rotating the plug while it was in contact with the seat. The cause of the small amount of outboard (45) valve leakage was believed to be small surface imperfections on the seating surface.

b. During the shutdown on July 10, 1991, while Unit 2 was at approximately 300 degrees F and 80 psig, the operator was unable to establish shutdown cooling (SDC) due to the suction valve cycling closed after opening the valve. The SDC valve logic was repaired and shutdown cooling was established. The failure was contributed to a poor wiring connection on the SDC isolation relay. A second SDC train was lined up to the fuel pool cooling system and was undergoing heat exchanger repairs, the third train was unavailable due to the overhaul of the discharge valve awaiting repair parts. A more detailed evaluation of licensee shutdown risk management is planned to be completed during the next inspection period.

c. At 0116 on August 17, 1991, Unit 3 scrammed during main turbine stop valve testing. When opening the number 2 stop valve all six combined intercept valves closed. Closure of the combined intercept valves reduced generator power from 394 MWe (47%) to 25 MWe with reactor power still at 47%. Eventually, the reverse power relay tripped the generator, the turbine and a reactor scram ensued.

The cause of the combined intercept valves' closure was a sluggish fast acting solenoid valve, which significantly reduced EHC header pressure. This reduction in header pressure was repeated while shutdown in special troubleshooting activities. Subsequently, the malfunctioning component was replaced with acceptable testing results achieved.

During the scram response operators did not observe the alarm typer print two seconds after the scram that a safety related 4160 volt bus had low voltage (approximately 4000). This was only an alarm typer alarm without an accompanying annunciator or acknowledgement capability.

The approximately 4000 volt alarm was to trigger operator response to a recent Electrical Distribution Funcitonal Inspection finding on the inability of safety related equipment to respond to a degraded grid condition above the degraded grid relay setting of 3708 volts. The operators were to turn on the swing emergency diesel generator cooling water pump and contact the load dispatcher to increase voltage.

The low voltage condition existed for approximately 1 1/2 hours before identified by operators and the appropriate actions taken. The low voltage condition was coincident with transfer from the auxiliary unit transformer to the reserve unit transformer. Also, at the time of the scram the swing diesel's water pump was being powered from the Unit 2 power distribution system, which does not appear to suffer from this same low voltage condition when transferring to its reserve unit transformer.

The original directive to the operators on this matter did not consider transient conditions and was inadequate in this respect. Subsequently, adequate instruction was placed in the scram response procedure as an operator action to check 4160 bus voltage.

No violations or deviations were identified.

10. Safety Assessment and Quality Verification (35502 and 40500)

a. The inspectors reviewed the post trip investigation (PTI) report, conducted per DAP 7-15, "Scram/Engineered Safety Features (ESF) Actuation Investigation Program", Revision 3, following the June 9, 1991, reactor scram. The reactor scram was the direct result of a high reactor pressure condition following a turbine trip at 42% power. The turbine tripped during a test of the thrust bearing wear detector. Following the turbine trip there was an approximate two minute window, prior to the reactor trip, during which the operator inserted control rod H8 to reduce reactor power and pressure. After the root cause determination was completed by the licensee, the inspector interviewed the investigation chairman, participating operations engineer, the reactor engineer, and the on-shift NSOs and SCRE.

The PTI data indicated reactor power was approximately 42% prior to the turbine trip. The plant has a bypass valve capability of 40% load, plus an additional 5% for station loads. After the turbine trip all the bypass valves opened fully. A loss of feedwater heating resulted in a positive reactivity insertion and an increase in reactor pressure. In this configuration, the plant was operating slightly above the bypass valve capability. After the high pressure annunciation, the SCRE directed the NSO to insert control rods. The NSO asked the SCRE whether he should use the CRAM arrays or reverse sequence. The SCRE directed him to use reverse sequence. H8 was the next rod to be inserted per the control rod sequence. However, the reactor scrammed prior to the full insertion of H8.

The PTI contributed the root cause of the event to instrument drift of the thrust bearing wear detector. The PTI indicated the scram could have been prevented if the reactor power was lower (approximately 300 Mwe). The PTI did not consider the potential effect of the use of CRAM arrays or reduction of recirculation flow as a method to reduce power and avoid the scram. The omission of the potential use of CRAM array or recirculation flow reduction in the PTI root cause investigation is considered a weakness in the trip investigation report.

In a subsequent interview with operating authority management, the inspector was informed that another report was to be issued by September discussing these aspects of the scram.

b. On July 4, 1991, an automatic closure of two reactor water cleanup (RWCU) Group III primary containment isolation valves (PCIV) occurred on Unit 2. The isolation resulted from a RWCU non-regenerative heat exchanger high pressure signal following a RWCU pump trip caused by an electrical perturbation while changing the open position indicating light bulb at the local control station for the RWCU return valve. On July 5, 1991, after senior station management reviewed the event during a routine planning meeting, the determination was made that the automatic closure of the PCIVs did

constitute an ESF actuation. The station subsequently made the required NRC notification about 17 hours after the event. ESF actuations are required to be reported to the NRC within 4 hours per 10 CFR 50.72(b)(2)(ii).

A previous violation of 10 CFR 50.72(b)(2)(ii) was issued (50-237/90027-06(DRP)) for failure to make the four hour NRC notification following an unplanned automatic closure of eight PCIVs on December 8, 1990. In response to the Notice of Violation, the licensee issued a memorandum to the on-shift operating authority to provide guidance on the definition of an ESF actuation. The guidance defined an ESF actuation to include any unplanned or unknown occurrence involving the actuation of an ESF train, which results in the completion of desired repositioning of any pieces of equipment. However, in neither the December 8, 1990, nor the July 4, 1991, events, did the PCIV logic initiate. Both events involved only the actuation of the end device. NUREG-1022, Licensee Event Report System, Supplement No. 1, Section II.6, clarified that an ESF actuation includes any automatic, spurious, or manual action that results in the actuation of the device to perform its intended function. In both events, the intended ESF safety function was the automatic closure of the PCIVs.

The inspector's interview determined that the SCRE believed the closure of the PCIVs did constitute an valid ESF actuation signal at the time of the event. However, after consulting with off-shift management, the decision was made not to make the NRC notification. This decision was based upon the closure initiation signal not driven by the primary containment isolation system. The SCRE was unaware of the guidance provided in NUREG-1022 or the operations memorandum. Additionally, the SCRE had not receive any additional training on reportability and was unfamiliar with the December 8, 1990, event. The Shift Engineer (SE) did review the operations memorandum during the reportability evaluation process. However, the "guidance" provided in the memorandum was confusing and the SE concluded an ESF actuation did not occur.

The failure to provide adequate corrective actions to prevent recurrence of the previous violation is considered a violation of (50-237/91022-10(DRP)) 10 CFR 50, Appendix B, Criteria XVI.

c. The inspectors performed an evaluation of the licensee's quality assurance program implementation. This involved a review of the licensee's Nuclear Quality Program (NQP) assessments and surveillances, and Offsite Nuclear Safety Group functions. A similar review of Onsite Nuclear Safety Group functions was described in Inspection Report 50-237/91016(DRP); 50-249/91016(DRP).

The inspector reviewed NQP audit reports and verified that appropriate corrective actions to findings were delineated and were being tracked by both NQP and the plant Nuclear Tracking System (NTS).

Findings were assigned a status level that would change to ensure greater management scrutiny if adequate corrective action implementation progress was not being accomplished. In addition, items greater than 60 days old were flagged in a special report. Previous findings were also incorporated into subsequent audits to evaluate the effectiveness of completed corrective actions. Audit planning was considered good in that related documents events and personnel were reviewed and/or interviewed to identify specific audit items. In addition, problems identified at other plants were reviewed for inclusion such as the Zion Diagnostic Evaluation Team issues.

The inspector's review of specific findings determined the licensee's shift to performance based audits to be beneficial in identifying implementation problems. Recent improvements in tracking capabilities were also being utilized to identify problem areas and to redirect resources. In addition to scheduled audits, special audits were performed in suspect areas. The inspector noted that team assessments previously conducted in different areas at various times during the year, were combined into one large yearly assessment of all areas conducted in January 1991. Staffing levels for the onsite NQP group appeared adequate with individual backgrounds from varying areas to ensure the ability to provide informed coverage of many disciplines. Two of the thirteen onsite NQP personnel were Senior Reactor Operator (SRO) licensed and two were SRO certified.

The Offsite Nuclear Safety Group (OFSG) responsibilities were delineated in Technical Specification 6.1.G. The inspector regarded recent OFSG findings and issues to be both relevant and a worthwhile contribution toward safe plant operation. However, the inspector noted that safety evaluations for certain classes of procedures were not being routed to the OFSG for review in accordance with the requirements of Dresden Administrative Procedure (DAP) 9-02), "Procedure and Revision Processing", Revision 24, Step F.7.c.(4). This DAP had been previously changed in response to an early 1990 NQP finding of a similar nature, to require procedures which have a completed Safety Evaluation Form 10-2C to be transmitted to OFSG. In addition, the inspector noted that an OFSG review dated October 1, 1990, (OFSG Tracking No. 12-90-204) indicated that the Unit 2 high pressure coolant injection (HPCI) steam line high flow isolation differential pressure transmitter had not been calibrated in two years and that no surveillance requirement existed. The OFSG participant for Dresden indicated that a review had been conducted for similar instrument calibration problems but that none were identified. Suggested corrective actions appeared specific to this type instrument. A more generic issue involving numerous instruments inappropriately omitted from periodic surveillance calibration requirements was subsequently identified by the NRC and was the subject of a previous violation (50-237/91016-02(DRP)). Actions in response to the previous OFSG issue did not identify the generic nature of the

finding. Both these issues are considered to be an unresolved item (50-237/91022-11(DRP)) pending completion and review of the licensee's root cause analysis of the first corrective action deficiency and further review of licensee actions regarding the second.

The inspector noted that coordination of improvement initiatives improved by the addition of an individual reporting directly to the Technical Superintendent. This individual was responsible for development of the Dresden Management Action Plan including ensuring timely implementation of planned activities.

d. The inspector reviewed the licensee's tracking and resolution of LER actions to assess managements effectiveness in this area. The LERs were reviewed for the nature of the event, the proposed corrective action, the assignment of NTS corrective action numbers, and the overall ability to consistently track and update the status of corrective action items. Additional reviews included evaluation of the adequacy of periodic updates on outstanding corrective actions along with the length of time that specific corrective action items remained open or unresolved. Of the seventy-one items reviewed, two problems were noted:

- LER 237/83-062 involved the Unit 2 HPCI motor gear unit (MGU) which was observed to have been oscillating between the high and low speed stops without operator action during a scheduled HPCI surveillance test. Corrective action delineated in the LER was to modify the HPCI control system (Modification M12-2-83-54), which would replace the MGU signal converter containing a sensitive operational amplifier and move the new amplifier to a less harsh environment. Latest up-dated corrective action as reported under the NTS corrective action summary indicated that the modification for replacement and relocation of the MGU signal converter had been canceled. No notification to the NRC had been made in regard to the change in LER corrective action commitments.

  Once identified to the licensee, the licensee stated that a revised LER would be submitted discussing the rational for cancellation of the modification.

- An excessive implementation period was identified for the corrective action items associated with LER 237/88-013. LER (237/88-013) resulted from a loss of power to an Analog Trip System Master Trip Unit. An outstanding commitment, resulting from the corrective actions, involved the development of a reference guide in order to determine the components affected when fuses were removed from circuit panels. The guide would be an instructional tool for removing fuses.

  Once identified to the licensee, the guide was completed and was in the procedure review cycle by the end of the inspection period.

One violation and no deviations were identified in this area.

11. Report Review

During the inspection period, the inspector reviewed the licensee's Monthly Operating Report for July 1991. The inspector confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16. The inspector also reviewed the Dresden Nuclear Power Station Monthly Plant Status Report for June 1991.

No violations or deviations were identified.

12. Violations For Which A "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the requirements set forth in 10 CFR 2, Appendix C, Section V.A. A violation of regulatory requirements identified during the inspection for which a Notice of Violation will not be issued is discussed in paragraph 4.d.

13. Unresolved Items

Unresolved items are matters which require more information in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. Unresolved items disclosed during this inspection are discussed in paragraphs 4.b., 4.c., 5, 6.c., and 10.c.

14. Open Items

Open items are matters which: have been discussed with the licensee; will be further reviewed by the inspector; and which involved some actions on the part of the NRC, licensee, or both. Two open items disclosed during the inspection are discussed in paragraph 4.d.

15. Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) during the inspection period and at the conclusion of the inspection period on August 22, 1991. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Dear Mr. Reed:

This refers to the routine safety inspection conducted by W. Rogers, D. Hills M. Peck, R. Greger, P. Rescheske, M. Kunowski and N. Shah of this office and assisted by R. Zuffa of the Illinois Department of Nuclear Safety on June 29 through August 22, 1991, of activities at Dresden Nuclear Power Station, Units 2 and 3 authorized by NRC Operating License Nos. DPR-19 and DPR-25 and to the discussion of our findings with Mr. E. Eenigenburg and others at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as described in the enclosed Notice. A written response is required. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the requirements of 10 CFR 2, Appendix C, Section V.A. This is the case with the violation discussed in paragraph 4.d of the enclosed inspection report. If you do not agree with our statement of your corrective actions, you are requested to inform us, in writing, within 30 days of the date of this letter. Otherwise, no reply to the violation is required and we have no further questions regarding this matter at this time.

In accordance with 10 CFR 2.790, of the Commission's regulations, a copy of this letter and the enclosure(s) will be placed in the NRC Public Document Room.

The responses directed by this letter (and the accompanying Notice) are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.