U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/87026(DRP); 50-249/87025(DRP)

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

Licensee: Commonwealth Edison Company
P. O. Box 67
Chicago, IL 60690

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

Inspection At: Dresden Site, Morris, Illinois

Inspection Conducted: July 24 through October 22, 1987

Inspectors: S. G. DuPont

P. D. Kaufman

Approved By: M. A. Ring, Chief
Projects Section 1C

11/12/87
Date

Inspection Summary

Inspection during the period of July 24 through October 22, 1987 (Reports No. 50-237/87026(DRP); No. 50-249/87025(DRP))
Areas Inspected: Routine unannounced safety inspection by the resident inspectors on previous inspection items, operational safety verification, followup of events, monthly maintenance observation, monthly surveillance observation, licensee event report followup, management meeting of August 18, 1987, and recent management (CECo) changes.
Results: Of the eight areas inspected, two violations were identified in one area, operational safety verification (Failures to meet Technical Specification limits and to observe requirements of an administrative procedure - Paragraph 3). No other violations or deviations were documented within the other seven areas.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
J Wujciga, Production Superintendent
*C. Schroeder, Services Superintendent
L. Gerner, Superintendent of Performance Improvement
T. Ciesla, Assistant Superintendent - Planning
D. Van Pelt, Assistant Superintendent - Maintenance
J. Brunner, Assistant Superintendent - Technical Services
J. Kotowski, Assistant Superintendent - Operations
R. Christensen, Unit 1 Operating Engineer
*E. Armstrong, Regulatory Assurance Supervisor
W. Pietryga, Unit 3 Operating Engineer
J. Achterberg, Technical Staff Supervisor
R. Geier, Q.C. Supervisor
D. Sharper, Waste Systems Engineer
D. Adam, Radiation Chemistry Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Supervisor
D. Saccomando, Radiation Protection Supervisor
*M. Jeisy, Q.A. Superintendent
R. Stols, Q.A. Engineer

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 the exit interview conducted on October 22, 1987, and contacted informally at various times throughout the inspection period.

2. Review of Previous Inspection Items (92702)

(Closed) Unresolved Items (237/80001-01 and 249/80001-01): Replace the Square "D" pressure switches on the diesel generators with seismically qualified pressure switches. The inspector reviewed the documentation pertaining to the replacement, qualification and testing of the Square "D" switches with Solon company seismically qualified pressure switches. The following work requests were reviewed and found acceptable: D12841 (Unit 2), D12831 (Unit 2/3) and D12830 (Unit 3). Additionally, the inspector reviewed the Special Operating Procedures SOP 81-5-49 which verified that the multi-start subsystem of the diesels was functional. These items are considered closed.

(Closed) Open Items (237/86001-01 and 249/86001-01): Emergency Diesel Generators may have possible cracking in the accessory drive housing assembly. The inspector reviewed the annual and biennial mechanical inspections performed in 1986 and 1987 as required by procedure DMP 6600-4, "Diesel Generator Annual and Biennial Mechanical Inspection," and verified that the engine internals and drive housings had been inspected for cracking. These inspections had revealed that the engines were in satisfactory conditions. This item is considered closed.

(Closed) Unresolved Item (249/86003-01): Piping vendor nonconformance reports to be evaluated for 10 CFR Part 21 reportability. Letters dated October 8 and 10, 1987, from the piping vendor (Mannesman Anlagenbau AG) to Mr. Henry P. Studtmam, Director Quality Assurance Maintenance, Commonwealth Edison, Zion Station, were reviewed by the inspector. The letters identified that there were no noncompliances requiring reporting as to 10 CFR Part 21 and all nonconformances were reviewed for 10 CFR Part 21 applicability. In addition, all material ordered for Dresden Unit 3 Recirculation Pipe Replacement retrofit was exclusively used for that project. This item is closed.

(Closed) Open Item (237/87013-01): Analysis of fluid found in limitorque MO-2-1301-1 is to be provided by the licensee. The licensee's evaluation was reviewed and found to be adequate. The motor operator was replaced and the evaluation indicated that the entry of the foreign substance could not be determined. The licensee also inspected two additional motor operators and did not detect any foreign substance. This item is considered to be an isolated occurrence and considered to be closed.

3. <u>Operational Safety Verification (71710, 71814, 71846, 71707)</u>

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the period from July 24 through October 22, 1987. 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.

a. During a control room tour on August 18, 1987, at about 8:00 a.m., with Unit 2 at 94% reactor power and in the run mode, an NRC inspector with the Diagnostic Evaluation Team noted the following conditions associated with the neutron monitoring system:

- APRM-4 bypassed with the joystick
- IRM-16 bypassed with the joystick
- IRM-17 out of service due to erratic response (caution tagged)

APRM-4 was bypassed at 12:19 a.m., on August 18, 1987, due to failed high APRM. This condition caused a half scram on Reactor Protection System (RPS) channel "B." The operators bypassed the APRM, declared it inoperable, and reset the half scram. IRM-17 had previously been declared inoperable due to erratic response and was logged in the Unit 2 degraded equipment log. There was no apparent reason for IRM-16 to be bypassed with the joystick. At 9:22 a.m., the operators un-bypassed IRM-16 and bypassed IRM-17. This was done after the NRC inspector brought the condition to the attention of the operating shift.

The NRC inspectors reviewed Technical Specifications Table 3.1.1 and RPS electrical schematics #12E-2464 through 2467. IRMs are companioned to APRMs in each RPS channel for APRM downscale trips. For RPS channel "B" the following relationship exists:

IRM	APRM
15	5
16	6
17	4
18	4

The APRM downscale trip function is required to be operable when the reactor is in the run mode. The minimum number of operable APRM downscale/IRM high high inoperable trip functions per RPS Channel is two. This APRM downscale trip function is automatically bypassed when the companion IRM is operable and not high. However, the existing condition that the NRC inspector noted was that only the IRM-15/APRM-5 downscale trip function was operable. This is because the other 3 channels in RPS Channel "B" were bypassed. Having only one operable APRM downscale trip function in RPS Channel "B" is an apparent violation of Technical Specification (TS) Table 3.1.1.

If the required minimum number of APRM downscale trip functions cannot be met, TS requires either: (1) insertion of all control rods within four hours, or; (2) reducing power to the IRM range and placing the mode switch to startup within 8 hours. Neither of these actions were taken by the licensee.

The inspector brought this condition to the attention of the licensed operators on shift and to the licensee operating management. The licensee concurred that it was an apparent violation of Technical Specifications Table 3.1.1. The licensee stated that this TS requirement for APRM downscale trips was apparently inadequately addressed in training and that adequate control of the IRM bypass switches when the reactor was in the run mode was not maintained. The licensee initiated a DVR and also submitted an LER (Unit 2 - #87-022-0) for this condition. The above mentioned training concern and control of the IRM bypass switches was corrected by the licensee and found to be adequate.

This is considered to be a violation of Technical Specifications Table 3.1.1 (50-237/87026-01); however, because of the prompt corrective actions, which are contained in Unit 2 LER #87022, such as training, etc., no written response is required.

b. During Unit 3 startup on September 4, 1987, at about 10:30 a.m. (CDT), the Resident Inspector observed the Unit 3 Nuclear Station Operator (RO licensed) directing the Nuclear Engineer (non-licensed) to manipulate the controls for the control rod drive system to increase drive pressure to assist unseating a stuck control rod drive off of the full-in position. Increasing of the drive pressure is normally done when control rod drives appear to be stuck during startups after the unit has been shutdown for extended periods and the drives are susceptible to sticking in the full-in position. Unit 3 had been in cold shutdown since August 7, 1987. The Resident Inspector discussed this condition with the licensee, the Acting Senior Resident Inspector and Region III management. It was determined that, although the manipulation of the control rod drive system drive pressure did not directly affect the reactivity or power level of the reactor as defined in 10 CFR 55.4(f), and as such is not a violation, it was not generally allowed by the licensee's policy and 10 CFR 50.54(j). The licensee held several meetings, as corrective action, with the nuclear engineers and nuclear station operators stressing that manipulations of control room panels were to be conducted by licensed operators and supervised trainees installed in formal license training programs only.

This issue was revisited by the resident staff on September 30, 1987, after reviewing the Executive Director for Operations' "Daily Staff Notes" dated September 28, 1987, discussing the recent event at Turkey Point where a non-licensed individual had been allowed to manipulate controls affecting the reactivity and power level of the Turkey Point reactor. Because of the similarity of the events, manipulations of controls by non-licensed personnel, the Dresden September 4, 1987 occurrence was discussed with the Region III and Commonwealth Edison Senior Management. Region III also discussed the occurrence with the Executive Director for Operations' Office and NRR. Although it was determined that the occurrence did not include manipulations that affected reactivity or power level changes of the reactor per 10 CFR 55.4(F), immediate corrective actions were warranted by both the licensee and the NRC per 10 CFR 50.54(J), since manipulations of the drive pressure could indirectly affect reactivity by resulting in control rod withdrawal notch overshoot. The licensee immediately issued a standing order on October 1, 1987, to provide instructions that only licensed operators or trainees in the license training program (under direct supervision of the licensed operator) could manipulate any of the controls in the control room. The instruction also noted that non-licensed personnel could only manipulate apparatus and mechanisms other than controls, such as nuclear instruments, during surveillances, calibrations and trouble shooting with the knowledge and consent of the licensed operator as per 10 CFR 50.54(J).

Commonwealth Edison also issued a corporate-wide directive to all their Nuclear Plants on manipulation of controls both affecting and not affecting the reactivity and power level of reactors.

Except for the September 4 occurrence, no other manipulations of any controls by non-licensed personnel have been observed (during the period since August 7, 1987, control room activities have been observed at near around-the-clock by members of the Diagnostic and Augmented Investigation Teams, and nine different inspectors observing the Feedwater System Testing, including senior resident inspectors from two other sites). The inspectors have no further concerns with this issue.

c. During routine observations of activities and review of shift manning documentation, NRC inspectors with the Diagnostic Evaluation Team noted that Nuclear Station Operators (NSO) had exceeded the recommended limits contained within the NRC policy statement "Nuclear Power Plant Staff Working Hours" and the requirements of Dresden Administrative procedure DAP 7-1, "Operations Department Organization." One individual was noted to have worked 96 hours during a seven day period without management's approval. This is considered a violation of DAP 7-1 limits of no more than 72 hours during any seven day period (237/87026-02 and 249/87025-01).

The licensee implemented several prompt corrective actions. A directive order was issued by the licensee to stop all overtime as a short term corrective action. Additionally, the licensee evaluated overtime controls including DAP 7-1. This review resulted in the issuance of DAP 7-21, "Station Policy on Reactor Operator and Senior Reactor Operator Manning Levels and Overtime." DAP 7-21 established improved controls to restrict exceeding working hours. These controls were reviewed by the Resident Staff and appear to be adequate. Additionally, the licensee initiated a program to include two extra NSOs during the day shift for assisting in administrative and operational functions. The extra NSOs are also available for overtime requirements to prevent back-to-back (16 hours) coverage of NSOs during the midnight and day shifts. Because of these corrections and the promptness of implementation, no response is required to the above violation.

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

e. The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the systems listed below to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verifying that instrumentation was properly valved, functioning, and calibrated. Event trending of personnel contamination incidents during this reporting period has shown a significant improvement in reducing the number of personnel contamination events. There were 36 incidents in August, 18 in September, and 24 so far in October. The licensee's Contamination

Control Action Plan recommendations and methods appear to be effective for improving a previous adverse trend at the Dresden Station.

The following systems were inspected:

Units 2 and 3	Feedwater System
Unit 3	Diesel Generator
Unit 2	Main Steam System
Unit 2	Control Rod Drive Hydraulic System
Unit 3	Low Pressure Coolant Injection System

f. 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.

g. 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.

Two violations were identified in this area.

4. <u>Followup of Events (92700)</u>

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements and that corrective actions would prevent future recurrence. The specific events are as follows:

a. Unit 2 - On August 5, 1987, during disassembly of a primary containment isolation valve (G33-F120), it was noted that the resilient seat was missing. The seat material is ethylene propylene rubber. The cause of the seat loss is believed to be wear. The plant was in cold shutdown at the time of discovery. The licensee completed replacement of the resilient seat during the maintenance outage on August 6, 1987.

b. Unit 3 - On August 7, 1987, the drywell vent to the standby gas treatment system motor-operated valve A03-1601-63 failed to close during the Unit 3 monthly surveillance test. Subsequent attempts to close the valve also failed and the valve was manually closed and declared inoperable. An Unusual Event was declared and the licensee commenced an orderly shutdown from 650 MWe (about 82% power) as required by the Technical Specification LCO. The licensee made the ENS notification and notified the Senior Resident Inspector. The licensee made an attempt to repair the valve; however, the valve failed the retest later on August 7. The licensee continued to shutdown Unit 3 as required by Technical Specifications. At approximately 30% power the Unit was manually scrammed when operators observed feedwater flow oscillations and possible leaks in the feedwater system. During the scram some control rods stopped at position 02 (one notch less than full-in). The position 02 is a historical problem at Dresden. This manual scram and manual MSIV closure (due to possible leak) caused the licensee to enter the isolation condenser mode of operation. The Unit was made stable in a hot shutdown condition. The Region initiated an Augmented Investigation Team on August 10, 1987, to review the feedwater system transient. The details of the investigation are contained in Inspection Reports No. 50-237/87029 and No. 50-249/87028.

Additionally, while shutdown and controlling pressure on the isolation condenser, Unit 3 received a second reactor scram on low vessel water level. The low water level was due to the amount of steam being drawn from the vessel by the isolation condenser. All control rods were already full-in prior to the low level scram. The steaming rate was reduced and vessel level was returned to above the scram setpoint.

c. At about 7:45 p.m. CDT, on August 7, 1987, the Dresden Power Station became aware that all normal outsite telecommunications (including ENS) were inoperable. The NRC was notified by the load dispatcher. The site had established communications with the load dispatcher via a radio link. The telephone company was also notified and the lines were repaired at about 11:30 p.m. CDT. The Senior Resident Inspector was dispatched to observe plant operations during the loss of communications. During the event, Unit 3 was shutdown and Unit 2 was at 100% power.

d. At approximately 7:00 a.m. (CDT), on August 19, 1987, the licensee found all normal outsite telecommunications (including ENS) inoperable. The site established communications with the Corp. Command Center via a radio link. The NRC duty officer was notified at 7:30 a.m., by the CECo Command Center. Repairs were completed to the phone lines and they were returned to service at 7:45 a.m., on August 19, 1987. During the event, Unit 3 was shutdown and Unit 2 was operating at 90% power. A similar event occurred on August 7 and is documented above.

e. Unit 2 - On August 21, 1987, at 5:55 p.m. CDT, Unit 2 scrammed on Reactor Vessel Water Low Level as a result of loss of feedwater. Prior to the scram, the unit was operating at about 95% power with two Reactor Feed Pumps (RFP) and level being controlled on the 2A Feedwater Regulating Valve (FRV) in automatic and the 2B FRV only 25% open in manual.

During the scram, all safety systems had responded as designed: however, several components did not fully respond, such as; two isolation valves on the isolation condenser system closed without an actuating signal, the 2C RFP appeared to have tripped (verified by annunciators) but the feedwater flow charts indicated flow through the 2C RFP, and 17 control rods had stopped at position 02. Additionally, the licensee discovered that the cause of the loss of feedwater was due to the 2A FRV stem and disc separating. The licensee conducted several inspections prior to startup. The inspections revealed no cracks on the six lines to the RFP discharge flow instruments (one of these lines failed on the August 7, 1987, Unit 3 feedwater transient), no cracks on the FRV stems for 3A, 3B and the replaced 2A FRVs. However, a crack was found on one pipe support on the condensate/feed line under the Unit 2 condenser. This crack was determined to not be related to the July 17 or August 21, 1987, feedwater transients. The licensee repaired the support and replaced the 2A FRV stem and disc assembly. Additionally, sticking relays which caused the two isolation valves to close were cleaned and tested satisfactorily. On August 27, 1987, the unit commenced a startup after the utility conferred with Region III management.

Additionally, this event did not cause any piping vibration, loss of pipe insulation or failures of any pipe support or piping.

f. Unit 3 - On September 4, 1987, at 9:50 a.m. (CDT), the licensee commenced a startup of Unit 3 following the Feedwater transient of August 7, 1987. The licensee's corrective actions to determine root cause of the event were reviewed by a Region III Augmented Investigation Team. Prior to startup, the licensee completed repairs on the two broken small bore piping lines, performed nondestructive examination on feedwater lines, replaced the 3A and 3B feedwater regulating valves' pneumatic diaphragm actuators with pneumatic damping actuators, performed walkdowns of the feedwater/condensate systems piping, repaired damaged feedwater pipe supports, prepared a special feedwater system high vibration test procedure, and instrumented the feedwater regulating valve station with data recorders and video cameras to monitor the special feedwater test. Licensee management conferred with Region III management on September 2, 1987, and obtained approval to begin unit startup as required by CAL-RIII-87-014.

g. Unit 3 - On September 5, 1987, while at 6% reactor power, the licensee declared the isolation condenser inoperable after it isolated on high condensate flow during a special test (SP-87-8-132), "Isolation Condenser Group 5 Isolation Flow Test." The test was being conducted to determine the cause of the Group 5 isolations during the August 7, 1987, feedwater transient. The water level on the shell side of the isolation condenser dropped below normal when a high condensate flow signal occurred, resulting in an unexpected Group 5 isolation. The licensee's investigation of the cause of the isolation resulted in a modification to the isolation circuitry. The licensee installed a time delay in the isolation circuitry per

Modification M12-3-87-37. The post-modification testing adequately demonstrated correction of the inadvertent isolation conditions.

However, before modifications could be completed, on September 6, 1987, with reactor power at about 17%, the licensee declared an Unusual Event and began a plant shutdown per the Tehnical Specification LCO action statement for inoperable isolation condenser and High Pressure Coolant Injection (HPCI) system. Previously, on September 5, 1987, the licensee determined that the isolation condenser was inoperable and subsequently the (HPCI) system was declared inoperable on September 6, 1987. While performing the monthly HPCI surveillance, valve 2301-10 (in the test return line to the condensate storage tank) would not fully close which prevented HPCI from achieving design discharge pressure. In addition, the licensee found that a packing follower nut had fallen off and the packing material was out of alignment. The packing assembly was repaired and locking nuts installed to prevent future recurrences. The HPCI gland seal leakoff blower trip was determined to be due to a high level problem in the HPCI gland seal leakoff condenser hotwell. Repairs consisted of replacing the gland seal leakoff drain pump. The Unusual Event was terminated at 4:50 p.m., on September 6, 1987, when reactor pressure was reduced to less than 90 psig. A unit startup was commenced on September 11.

h. Unit 2 - On September 10, 1987, piping vibrations were noticed on the "B" Feedwater system and flow oscillations existed on the "B" feedwater regulating valve (FRV). The unit operator made several unsuccessful attempts to dampen the oscillations by increasing and decreasing flow through the FRV, opening and closing the "B" FRV in manual, cycling the controlling FRV "A" from automatic to manual and back to automatic, and opening the feedwater pump minimum recirculation flow. Flow oscillations dampened after the "B" FRV was isolated closed and power had been increased to about 40%.

Prior to the flow oscillations starting, the unit dropped in load from about 90% to below 40% to perform the recirculation pump and jet pump operability base line. The oscillations are believed to have started at about 30% power. Throughout the flow oscillations, no insulation or piping damage occurred. However, while the "B" FRV isolation valve was being closed, the pneumatic supply line to the "B" FRV actuator cylinder broke. Since the line maintains air pressure on the above side of the piston, the FRV ramped to the full open position. However, no increase in reactor vessel water level occurred because the isolation valve was partially closed, minimizing the increase in feedwater flow. The licensee stabilized level control at 40% power and evaluated the oscillations prior to changing power.

i. Unit 3 - On September 12, 1987, with Reactor Power at 12%, the licensee declared the High Pressure Coolant Injection (HPCI) system inoperable. While conducting the HPCI monthly operability surveillances at 920 psig, the gland seal leakoff blower tripped due to high water level in the HPCI gland seal leakoff condenser. The licensee determined that the problem was associated with Pressure Control Valve (PCV) #3-2301-46 which is located in the cooling water discharge line from the HPCI booster pump to the gland seal leakoff condenser and was found stuck open. This caused back pressure from the HPCI pump to "dead head" the hotwell drain pump, so that it could not pump down the condenser hotwell. Repairs to the PCV included changing a diagram in the air operator and inspecting, cleaning and lubricating all internals of the operator.

On September 13, 1987, an Unusual Event was declared because the HPCI system was determined to be inoperable at 10:00 p.m. CDT, on September 12, 1987, and the other Emergency Core Cooling Systems (ECCS) were not tested as required, but instead an orderly shutdown was initiated and reactor pressure reduced to less than 90 psig within 24 hours after completing a special "Main Generator Reverse Power Trip Test" (SP-87-8-138), which the licensee discussed with the NRC Region III management. The special test was completed at 3:45 a.m., and unit shutdown began at 4:35 a.m., on September 13, 1987, when reactor pressure was reduced to less than 90 psig. The HPCI problem was resolved and the licensee commenced a unit startup from hot standby on September 13, 1987.

j. Unit 3 - On September 15, 1987, at about 4% reactor power, the High Pressure Coolant Injection system minimum flow valve (3-2301-14) failed closed after the HPCI pump and valve surveillance had been completed. The valve's thermal overload breaker had tripped and the licensee reset the overloads. The valve was then tested; however, the overloads again tripped. The licensee issued a maintenance work request to determine the cause of the tripping overloads. On September 16, the licensee determined that HPCI was inoperable because of the valve failure and made the ENS notification. However, after further evaluations, the licensee determined that HPCI had been inoperable since initial valve failure on September 15. The licensee notified the NRC duty officer of the error at 12:25 p.m. (CDT), on September 16. The licensee commenced the testing of the other ECCS systems and the isolation condenser as required by Technical Specifications.

k. Units 2 and 3 - On September 18, 1987, at about 2:30 a.m. (CDT), the licensee declared an Unusual Event because of the failure of the Standby Gas Treatment System to maintain the Technical Specification requirement of .25 inch H_2O differential between the secondary containment and the atmosphere during the secondary containment leak rate test. The licensee notified the NRC duty officer via ENS and commenced a dual unit shutdown as required by the Technical Specification 3.0.A, since the secondary containment Technical Specification does not have an associated action statement. The units were operating at 93% (Unit 2) and 56% (Unit 3) power when the licensee commenced the dual unit shutdown.

The licensee made repairs to the seals of the Unit 2 truck bay door and the primary/secondary containment interlock doors. The licensee investigated other possible leakage paths and repaired several minor seals prior to reaching cold shutdown. The licensee verified that no release had been made.

However, on subsequent testing on September 18, 1987, the licensee declared an additional Unusual Event because of the failure of the Standby Gas Treatment System to maintain the Technical Specification requirement of .25 inch H_2O differential between the secondary containment and the atmosphere. Both Units 2 and 3 were shutdown at 6:25 p.m. CDT, on September 18 and the Unusual Event was terminated.

The licensee remained shutdown for greater than 48 hours because of failures of several attempts to achieve .25 inch H_2O differential. The licensee continued to investigate and repaired several possible leakage paths prior to achieving the required differential on September 21, 1987.

l. Unit 2 - On September 22, 1987, at about 10:45 a.m. CDT, a potential minor water hammer or transient occurred while placing the "A" Low Pressure Coolant Injection (LPCI) train in the Torus cooling mode. The water hammer was heard and pipe vibration was seen by plant personnel. The pipe of interest was the LPCI upper drywell spray line. A visual inspection of the system was conducted and no damage was identified. One base plate, however, was found to have loose bolts. These loose bolts were determined to be not related to the event and were tightened. The licensee also verified the stroke of all snubbers (10 total) on the affected line.

The results of the above inspections and stroke testing did not reveal any physical evidence that a water hammer had occurred on September 22, except for the verbal reports from personnel in the plant. However, the licensee continued to investigate possible causes and developed a plan to monitor the water volume in the suspected LPCI piping. The LPCI system was not inoperable at any time during the event.

m. Unit 3 - On September 28, 1987, Unit 3 scrammed from approximately 80% power. An instrument mechanic was performing a calibration surveillance on the Main Steam Line High Flow Isolation switches when the scram occurred. The mechanic noticed that a spurious pressure spike had occurred at about the time of the scram. The licensee reviewed the calibration method and other possible causes of the spurious signal and determined that the root cause was personnel error. The unit was returned to operation on September 29, 1987.

n. Unit 2 - On October 1, 1987, with reactor power at 95%, the licensee declared the High Pressure Coolant Injection (HPCI) system inoperable. While conducting the HPCI monthly operability surveillances DOS 2300-3 and DOS 2300-6 an equipment operator noticed steam leaking from the HPCI turbine room. Further investigation by a Shift Foreman determined that the large steam leak was coming from the turbine shaft seal area of the HPCI pump. The HPCI system was subsequently secured and declared inoperable. The licensee made the required ENS call. The licensee commenced testing of the other ECCS systems, with the exception of Core Spray and Low Pressure Coolant Injection which had been previously tested satisfactorily approximately one hour before HPCI was declared inoperable. The licensee discussed this with NRC Region III management prior to taking any action with respect to the LCO Action Statement.

o. Unit 2 - On October 3, 1987, with reactor power at 93%, the licensee experienced an ESF actuation when the Reactor Building Ventilation system isolated and the Standby Gas Treatment (SBGT) system automatically started due to Refueling Floor high radiation. The licensee was in the process of removing a fuel cask from the Unit 2 fuel pool when the Refueling Floor area radiation monitor (ARM) alarmed and isolated the Unit 2 Reactor Building ventilation system and started the SGBT system. Unit 3's Reactor Building ventilation system was manually tripped by the Unit 3 operator per the procedure. The cause of the high radiation was due to a hot piece of material, believed to be a 3 inch long piece of an LPRM detector tube, which was found attached to a plastic boot protector on the fuel cask while it was being raised in the fuel pool. The hot piece of material was removed from the cask along with the plastic boot protector while the cask was still under water, but apparently floated to the surface and set off the area radiation monitor. The hot piece of material was washed off of the plastic boot protector while in the fuel pool and radiation levels returned to normal. While the SGBT system was running the licensee noticed the differential pressure for the Reactor Building to be low, but still within the required limits and investigated the problem for minor seal leaks.

p. Unit 2 - On October 4, 1987, with reactor power at 99%, the licensee determined that the suction valve for the 2B Low Pressure Coolant Injection (LPCI) Pump was inoperable. The licensee was in the process of performing the surveillances required to take the Unit 2 Emergency Diesel Generator out-of-service for routine preventive maintenance when this occurred. The valve could not be opened after having been closed earlier in the surveillance. The 2B LPCI Pump was declared inoperable at this point and the necessary Technical Specification surveillances were commenced. At this point the licensee was in a 30 day LCO. Subsequently, on October 4, 1987, the licensee determined that one of the fans on the 2C Containment

Cooling Service Water (CCSW) vault cooler was inoperable (the CCSW system provides cooling for the LPCI heat exchangers). With both the LPCI 2B Pump and the 2C CCSW Pump inoperable, the licensee entered the appropriate Technical Specification LCO which required that the reactor be in Cold Shutdown within 24 hours. At 9:40 p.m. (CDT) on October 4, 1987, the licensee declared an Unusual Event as a result of the required shutdown. The licensee notified the NRC Duty Officer via the ENS and commenced an orderly shutdown.

Subsequently, the licensee replaced the torque switch on the 2B LPCI suction valve motor, tested the valve, and declared it operable, thus terminating the Unusual Event on October 5, 1987. This placed the licensee back in a 30 day LCO which was terminated when the 2C CCSW Vault Cooler was later repaired. Reactor power had been reduced to 65% prior to the termination of the Unusual Event.

q. Unit 3 - On October 8, 1987, the licensee completed the post modification testing of the Feedwater System. The testing was successful in verifying that the modified Feedwater Regulating Valve (FRV) operator compensated for the internal hydraulic forces associated with the feedwater system and the reactor feedwater pumps during conditions similar to those of the transients of July 11 and August 7. The modifications to the FRV included a pre-loaded hydraulic damping spring and a new pneumatic valve position operator with two chambers, but with pneumatic loading on only the above diaphragm chamber.

The testing also produced no evidence that the transients of July and August were related to feedwater/condensate check valve failures. However, the evaluation of the testing data has not yet been completed to determine the root cause(s) of the transients and, as such, is an open inspection item until the NRC can review the test data (50-249/87025-02). The licensee is also planning two additional modifications: To remove the 3B FRV and replace it with an electro-hydraulically controlled drag valve for increased stability in the lower feedwater flow regions; and to modify the Unit 2 feedwater system by replacing the 2A FRV with a hydraulically dampened-two chamber pneumatic operator and modifying the 2B drag valve by replacing the pneumatic operator with an electro-hydraulic controller. These modifications have not yet been scheduled.

r. On October 20, 1987, Unit 2 scrammed from about 100% power. The scram occurred during performance of the Main Steam Line functional test on the "C" Line Radiation Monitor. At the same time, a spurious scram signal occurred on the "B" Line Low Pressure Monitor. The "B" Line Low Pressure switches have a history of spurious scram signals caused by vibration of the switches. Since January 1987, there have been 27 half scrams and isolations, including two half Group I isolations on October 12 and 14, associated with the "B" Low Pressure switches (all but one at above 90% power) and one reactor scram (on October 20). The licensee had previously initiated a modification to install vibration dampers, but had not completed the engineering review/procurement until recently. Because of the scram, the licensee's management decided to install the modification prior to commencing a unit startup from the scram.

The modification was completed on October 21, 1987, and the unit was returned to power. The Resident Staff observed the modification installation and will observe the unit performance to evaluate the effectiveness of the modification.

No violations or deviations were identified in this area.

5. Monthly Maintenance Observation (62703, 71710)

Station maintenance activities of 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 following maintenance activities were observed/reviewed:

Unit 2	2A Feedwater Regulating Valve (FRV) Stem and Plug Replacement
Unit 2	Modification of Main Steam Line Low Pressure Switches 2-261-30B and 2-261-30D.
Unit 3	Feedwater System Piping Hanger Repairs
Unit 3	Modification of 3A and 3B FRV and Actuator Replacement
Unit 3	Isolation Condenser Isolation Circuit Troubleshooting

No violations or deviations were identified in this area.

6. Monthly Surveillance Observation (61726)

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:

Special Test of Unit 3 Feedwater System

Unit 3	Standby Gas Treatment System functional
Unit 3	Isolation Condenser isolation function
Unit 3	Main Steam Isolation Valve quarterly timing
Unit 3	Source Range Monitor (SRM) Rod Block functional
Unit 3	Intermediate Range Monitor (IRM) Rod Block functional
Unit 3	SRM Detector Position functional
Unit 3	IRM Detector Position functional
Unit 3	High Pressure Coolant Injection (HPCI) pump and valve operability
Unit 3	Main Steam Line Radiation Monitoring functional
Unit 2	HPCI pump and valve operability
Unit 2	Low Pressure Coolant Injection operability
Unit 2	Half Core Scram test

No violations or deviations were identified in this area.

7. Licensee Event Report Followup (93702)

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 in accordance with Technical Specifications:

Unit 2

(Closed) 87022-00: Operable APRM Downscale Trip Channels Less Than Allowable Due to Bypassing of APRM 4 While IRM 16 was in Bypass. Review of this event is documented under Paragraph 3 of this report.

(Open) 87023-00: Reactor Scram During Power Operation due to Low Reactor Water Level Resulting From Unanticipated Closure of the 2B Feedwater Regulating Valve. Onsite followup review of this event was conducted and documented under Followup of Events in Region III Inspection Report No. 50-237/87017, Paragraph 5.h. This LER will remain open pending review of the licensee's task force investigation into the root cause for the feedwater level control system equipment difficulties encountered during this event. The licensee will submit a supplement to this report at a future date explaining the task force findings and further corrective actions.

(Closed) 87024-00: Unit 2 Reactor Scram on Low Level Due to 2A Feedwater Regulating Valve Failure. Review of this event is documented in this report under Paragraph 4, Followup of Events.

(Closed) 87026-00: Low Reactor Water Level Scram Switch Found Below Setpoint Limits Due to Logic Card Instrument Drift. The as-found low level scram setpoint was thirteen (13) inches below instrument zero. The Technical Specification limit, when compensated for 100% steam flow, is 8 inches above instrument zero.

The Rosemount master trip unit logic card was replaced and its setpoint was adjusted back to the specified limits within one hour. The licensee will submit a supplement to this LER upon completing the determination into the root cause of the logic card drifting out of calibration.

Unit 3

(Closed) 86022-01: Standby Gas Treatment System Automatic Actuation Due to a Failed Fuel Pool Floor Radiation Monitor Resulting From a Failed Geiger Mueller Tube. This supplemental report was issued to document the root cause of failure for the fuel pool area radiation monitors. Cause has been attributed to component failure of VTIL COMP 3-1705-16B. The Geiger Mueller tube, resistors R1 and R2 and capacitor C2 were the failed components of the downscale event. The upscale event has also been attributed to the failed Geiger Mueller tube.

(Closed) 87012-00: Main Turbine Trip on High Reactor Water Level and Subsequent Reactor Scram Due to Malfunction of the 3A Feedwater Regulating Valve. Onsite followup of this event was conducted and documented under Followup of Events in Region III Inspection Report No. 50-249/87016, Paragraph 5.f.

(Closed) 87013-00: Manual Reactor Scram Due to Reactor Feedwater Oscillations During Unit Shutdown Due to Failure of Air Operated Containment Isolation Valve AO-3-1601-63 to Close During Surveillance Testing. Documented followup of this event is contained in Paragraph 3 of this report and in Region III Augmented Investigation Team Inspection Reports No. 50-237/87029 and No. 50-249/87028.

(Closed) 87014-00: Plant Shutdown Due to Inoperable High Pressure Coolant Injection and Isolation Condenser System. Onsite review and followup of this event is documented in Paragraph 3 of this report.

(Closed) 87017-00: HPCI System Inoperable Due to Tripping of the Gland Seal Leakoff Blower Caused by Condenser Overflow. Review of this event is documented under Paragraph 3 of this report.

(Closed) 87028-00: Failure of Secondary Containment Leak Test Due to Excessive In-Leakage. Review of this event is documented under Paragraph 3 of this report.

The preceding LERs have been reviewed against the criteria of 10 CFR 2, Appendix C, and the incidents described meet all of the following requirements or are being examined in other reports. Thus no Notice of Violation is being issued for these items.

a. The event was identified by the licensee,
b. The event was an incident that, according to the current enforcement policy, met the criteria for Severity levels IV or V violations,
c. The event was appropriately reported,
d. The event was or will be corrected (including measures to prevent recurrence within a reasonable amount of time), and
e. The event was not a violation that could have been prevented by the licensee's corrective actions for a previous violation.

(Closed) 87027-00: Failure to Perform Technical Specification Surveillance Within the Required Time Period Due to Personnel Error. This LER involved a missed critical surveillance due date of September 6, 1987, for DTS 500-2, "Calibration and Functional Testing of Reactor Protection System (RPS) Motor-Generator (MG) Set Electrical Protection Assemblies (EPAs)." While the surveillance coordinator was reviewing the computer surveillance printout sheets at 8:00 a.m., on September 16, 1987, it was discovered that this surveillance was missed. DTS 500-2 was successfully completed at 11:40 a.m., of the same day. The RPS MG set EPA relays functioned properly during the surveillance, thus the RPS system was not operating in a degraded condition.

Technical Specification (TS) 4.1.A.3.a. requires functional testing at least once per six (6) months of the Reactor Protection system (RPS) Motor-Generator (MG) Set Electrical Protection Assemblies (EPAs). Failure to perform TS Surveillance within required time period is a violation of TS 4.1.A.3.a (237/87026-03; 249/87025-03). This violation meets the tests of 10 CFR 2, Appendix C, consequently, no Notice of Violation will be issued and this item is considered closed.

(Closed) 87025-00: Failure to Obtain Grab Sample of Unit 2/3 Chimney Effluent Due to Personnel Error. A Radiation-Chemistry Technician failed to take a noble gas grab sample during the afternoon shift on September 3, 1987. Technical Specification Table 3.2.5 requires samples to be taken once per shift. The grab sample error was discovered on September 4, 1987. Samples taken prior to or subsequent to the missed sample were both well within the allowable ranges and it was evaluated that the chimney effluent was also within the allowable limits during the missed sample.

The failure to obtain 2/3 chimney noble gas grab samples as required once per shift with the 2/3 chimney SPING (Separate Particulate Iodine and Noble Gas Monitor) out of service is a violation of Technical Specification Table 3.2.5 (237/87026-04; 249/87025-04). This violation meets the tests of 10 CFR 2, Appendix C; consequently, no Notice of Violation will be issued and this matter is considered closed.

Two violations were identified in this area.

8. Management Meeting

A management meeting was held on August 18, 1987, at the NRC Region III Office in Glen Ellyn, Illinois. The meeting was held to discuss the guidance Commonwealth Edison is preparing to issue to its nuclear stations regarding the proper interpretation of Technical Specification 3.0.A (Standard Technical Specification 3.0.3). There was also some discussion of other Dresden Technical Specifications.

9. Management Changes

On September 30, 1987, the licensee announced that effective October 5, 1987, Mr. R. Flessner, Services Superintendent will be transferred to CECo Corporation Nuclear Station Division Staff. Services Superintendent at the Braidwood Station, Mr. C. Schroeder, will replace Flessner.

Effective October 5, 1987, Mr. L. Gerner was transferred from CECo Corporation Nuclear Station Division Staff to Dresden as the Superintendent of Performance Improvement, a newly created position.

10. Report Review

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Reports for July, August and September, 1987. 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 4.

12. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) informally throughout the inspection period and at the conclusion of the inspection on October 22, 1987, 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 inspectors during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.