U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No: 50-237/97028(DRP); 50-249/97028(DRP)

Licensee: Commonwealth Edison Company

Facility: Dresden Nuclear Station, Units 2 and 3

Location: 6500 N. Dresden Road
Morris, IL 60450

Dates: November 23, 1997, to January 12, 1998

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EXECUTIVE SUMMARY

Dresden Generating Station, Units 2 and 3
NRC Inspection Report No. 50-237/97028(DRP); 50-249/97028(DRP)

This inspection included routine resident inspection from November 23, 1997, to January 12, 1998.

Operations

- The material condition of the HPCI system impacted system availability and required operator work-arounds to assure HPCI system operability. Repetitive equipment problems with the gland seal condenser level switch caused Unit 3 HPCI to be declared inoperable, and the alignment of the condensate storage tank once caused both HPCI systems to be declared inoperable. (Section O2.1)

- The licensee's response to identified errors in the setpoints for system oil temperatures was poor. The licensee's original explanation of setpoint tolerances was incorrect, and the situation was not addressed until operators wrote a second problem identification form. (Section O2.1)

- The operators' response to the automatic reactor trip was good. The inspectors concluded that the actual safety consequences of this event were low. Operator and plant equipment response were generally as expected for an automatic reactor trip from full power. The exception involved the response of the feedwater level control (FWLC) system which over filled the vector vessel; however, in this case there were no adverse consequences from the level overshoot since the HPCI system was already isolated for troubleshooting efforts. (Section O4.1)

- Operations personnel exhibited safe operating practices during the startup of Unit 2 that commenced on December 26. Crew briefs and heightened level of awareness briefs were informative, contingency actions were discussed, and peer checks were performed. (Section O4.2)

- The operations staff was slow to declare the HPCI system inoperable following the gland seal leak off condenser low level switch failure on December 29, 1997. More than 17 hours passed from the first symptom until operations recognized that the system was inoperable. Even after recognition, the limiting conditions for operation were not retroactively entered. (Section O4.3)

- Operators generally were knowledgeable of the HPCI system parameters, settings, and requirements. The inspectors identified one instance involving turbine lube oil temperature where the requirements were not known. (Section O4.4)

- The licensee failed to follow the procedural requirements to provide feedback to the problem identification form (PIF) originator. Subsequent to the inspectors' review of the process, the licensee independently identified this procedural adherence concern and entered it into the corrective action program. The licensee met the procedural requirements before the end of the inspection period. (Section O7.1)

Maintenance

- Collectively, equipment failures and material condition issues involving a control rod drive, a torus cooling test valve, an HPCI isolation, erratic operation of a recirc motor generating set, the offgas system, reactor water cleanup and feedwater level control, represented challenges and distractions for operators and other plant staff. The issues especially represented a burden to operators who had either to respond to the original event, or to take additional compensatory actions. (Section M2.1)

- The inspectors were also concerned with the licensee's ability to resolve the issues effectively and eliminate deficiencies. (Section M2.1)

- On December 13, work performed without referencing a required procedure, combined with material condition, resulted in a trip of the Unit 3 125 V battery charger and placed both units unexpectedly into a two-hour limiting condition for operations. The subsequent follow up work was not performed in accordance with station administrative procedures. Specifically, the "condition" met sign off was used when a condition had not been met. (Section M4.1)

- Not all rework was captured into the rework trending program. (Section M8.1)

Engineering

- The inspectors concluded that the licensee's root cause team performed a thorough investigation of the reactor trip, the root cause, and equipment response following the reactor scram. The licensee's team concluded that the root cause of the event was the failure to perform the actions identified in GE SIL 500 regarding local power range monitor spiking. The inspectors' review reached the same conclusion.

- The FWLC system response presented a potential challenge to the operators following the reactor scram. The compensatory actions that the operators were required to take following a scram on Unit 2 were operator work-arounds. Pending permanent resolution of the Unit 2 FWLC system issues, the station was relying on operator intervention following a scram to prevent water intrusion into HPCI steam lines. (Section E1.2)

- Operability evaluations appeared to meet the licensee's requirements. The evaluations were reasonable and provided adequate bases for the conclusions. (Section E2.1)

Plant Support

- The setup and control of contaminated areas and work in contaminated areas were usually correct. (Section R4.1)

- The inspectors identified one example of an improperly secured hose that crossed a contamination boundary. The hose had been staged in response to a poorly performing sump pump. (Section R4.1)

- The inspectors were concerned with the lack of attention to detail exhibited by the plant staff to radiation controls, and that the PIF record showed this to be an emergent trend. (Section R4.1)

Report Details

Summary of Plant Status

Unit 2 started the reporting period in a load recovery from the power reduction required for single-loop operations and 2A feedwater regulating valve (FWRV) work. On December 3, power was reduced to about 600 MWe for repair of the 2E condensate demineralizer service unit. Recovery started on December 8, but oscillations on the 2A FWRV delayed full-power operations until December 12. On December 23, Unit 2 automatically scrammed from full power due to a local power range monitor (LPRM) spike, and a forced outage was entered (D2F30). Unit 2 was placed back on the grid by December 27.

Unit 3 maintained full power throughout most of the period. On December 6, load was reduced to mitigate a fire in the off-gas piping. Several times during the period, load was reduced to attempt to address problems with the 3B reactor water cleanup demineralizer bed. Maximum power on Unit 3 was slightly limited to maintain the average turbine control valve positions less than 85 percent.

Maximum power on both units was limited by feedwater flow. Feedwater flows were limited to 9.735 Mlbm/h to remain within the anticipated-transient-without-scram (ATWS) analysis. The licensee was pursuing additional analysis to remove this restriction.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. Overall, the conduct of operations was safe and according to procedures.

During the inspection period, several events occurred for which the licensee was required by 10 CFR 50.72 to notify the NRC. The events and the notification dates are listed below:

11/26/97 (Units 2, 3) Units 2 and 3 HPCI systems declared inoperable after engineering determined that HPCI system operation could result in air intrusion into HPCI system.

12/01/97 (Unit 3) Failure of torus cooling outboard test valve caused a potential for diversion of cooling flow from the reactor during a design basis loss of coolant accident.

12/06/97 (Unit 3) Control rod inserted into the core during a surveillance test. The event report was retracted on 12/18/97 after the licensee concluded that the event was not an engineered safety feature (ESF) actuation.

12/12/97	(Units 2, 3) Loss of 138 kV line that fed the lift station required operating the units in lake-bypass mode violating the national pollution discharge elimination system permit. Offsite notification made to the Illinois emergency management agency.
12/22/97	(Unit 2) ESF Actuation - HPCI Isolation during a routine surveillance for unknown reasons.
12/23/97	(Unit 2) Full reactor scram from 100 percent power due to a spurious APRM signal during an unrelated surveillance of reactor vessel high pressure scram signals.
12/29/97	(Unit 3) HPCI system declared inoperable due to failure of gland seal condenser low level switch.
1/07/98	(Units 2, 3) Unanalyzed condition that may significantly compromise plant safety identified when calculations showed the post-LOCA reactor building temperatures to be significantly higher than the limiting value stated in the UFSAR.

O2 Operational Status of Facilities and Equipment

O2.1 (Units 2, 3) Engineered Safety Feature System

a. Inspection Scope (71707)

The inspectors conducted a detailed review of the Unit 2 and Unit 3 High Pressure Coolant Injection (HPCI) systems to verify operability, assess the performance, and assess material condition of the systems. The inspectors also performed a cursory walkdown of the HPCI system to ensure that the alignment procedures, piping and instrumentation diagrams (P&ID), and the as-built configurations were current. The inspectors reviewed the following operating procedures, schematics, and the results of quarterly operability surveillances against information established in the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS), and the licensee's operation training manual:

- DOP 2300-01 Unit 2(3) HPCI System Standby Operation, Rev. 15
- DOP 2300-02 Unit 2(3) HPCI System Turning Gear Operation, Rev. 06
- DOP 2300-03 Unit 2(3) HPCI System Manual Startup and Operation, Rev. 24
- DOP 2300-M1/E1 Unit 2(3) HPCI System Checklist, Rev. 15
- DOS 2300-03 Unit 2(3) HPCI System Operability Verification, Rev 49
- DOS 2300-07 Unit 2(3) HPCI Fast Initiation Test, Rev. 18
- P&ID M-51, HPCI Piping Unit 2,
- P&ID M-374, HPCI System Piping Unit 3.
- WR No. 970093784-01 Unit 2 Quarterly TS HPCI Pump Test (IST Program) dated Nov. 19, 1997
- WR No. 970094986-01 Unit 3 Quarterly TS HPCI Pump Test (IST Program) dated Nov. 26, 1997

b. Observations and Findings

During walkdown of the HPCI systems, the inspectors determined that the alignment of the systems was in accordance with the operating procedures. The inspectors also noted that housekeeping for both Unit 2 and Unit 3 HPCI system rooms was good.

The inspector noted several oil leaks throughout both the Unit 2 and Unit 3 HPCI systems. The licensee also noted these leaks and had written action requests (ARs) to address the deficiencies.

The Unit 2 HPCI System room was at elevated temperature due to steam leaking past the HPCI steam supply shutoff valve (2-2301-3) and into the HPCI floor drain sump through the HPCI stop valve above seat drain line.

Front Standard Temperatures

On December 19, the inspectors noted that the alarm setpoints for four temperature dial switches (Unit 3 HPCI bearing oil cooler outlet temperature, Units 2 and 3 low pressure bearing drain oil temperature, and Unit 2 thrust bearing oil drain temperature) shown on the HPCI system front standards appeared to be at different settings than listed in the Dresden Annunciator Procedures (DANs) associated with the alarms. The inspectors informed the Unit 3 Unit Supervisor (US), who contacted the system engineer and wrote a problem identification form (PIF) to document the concern. The PIF was subsequently canceled by the PIF screening committee.

The system engineer reviewed the alarm setpoints and concluded that the settings were within the allowed tolerances based on a review of the instrument maintenance department (IMD) data cards.

The IMD data card showed that the allowed tolerance for temperature indicator face value was +/-5°F and the tolerance for the dial switch was +/- 2°F. Using this information, the system engineer thought that the two tolerances could be added to give an acceptable tolerance of +/- 7°F. The inspectors questioned this conclusion, and determined that the appropriate tolerance for the dial switch was only +/- 2°F.

The inspectors also reviewed the instrument maintenance department (IMD) data cards for the instruments and concluded that the instruments were originally set correctly, but had subsequently drifted out of tolerance. In one case the temperature dial alarm setting was greater than 5°F outside tolerance, upscale. In another case, the setting was 16°F outside tolerance, downscale. The inspectors informed operations that a concern still existed, and operations wrote a new PIF to document the concern. The licensee eventually wrote an Action Request (AR) tag to correct temperature switch settings.

The inspectors determined that the out-of-tolerance-temperature switches did not make the HPCI system inoperable.

Exhaust Drain Pot Alarms

The control room logbooks documented that the Unit 2 HPCI system exhaust drain pot high level alarms were annunciating at least once a day. The US explained that condensation resulting from seat leakage of the Steam Supply Shutoff Valve (2-2301-3) caused an abnormal input to the exhaust drain pot via the stop valve above seat drain line.

The licensee concluded in Engineering Operational Problem Response/Troubleshooting Plan (EOPR) 98-02-23-318, Rev. 0, that operations personnel needed to take compensatory actions to ensure the operability of the HPCI system. The compensatory actions included the non-licensed operators (NLOs) manually draining the exhaust drain pot once per week. The EOPR suggested that the quantity drained be evaluated and the draining frequency adjusted as needed. The inspectors concluded that the EOPR appeared reasonable.

The Operations Department declared the HPCI drain pot level high alarm as a control room distraction, and considered the draining to be an operator work-around.

HPCI System Availability

As stated in Section O1.1, three issues resulted in one or both HPCI systems being declared inoperable during this inspection period. On November 26, both units' HPCI systems were declared inoperable after engineering determined that air intrusion into HPCI system could occur due to condensate storage tank (CST) alignment. On December 22, during a routine surveillance test, the Unit 2 HPCI system unexpectedly isolated for unknown reasons. On December 29, the Unit 3 HPCI system was declared inoperable due to failure of the gland seal condenser low level switch. Similar problems with gland seal condenser level were discussed in Licensee Event Report (LER) 50-249/97-09-00 and LER 50-237/97-013-00, and in Inspection Reports (IR) 97012, 97019, 97024. Additional follow-up for all three issues will be tracked through the LER.

c. <u>Conclusion</u>

The HPCI systems were properly aligned in accordance with procedures.

The material condition of the HPCI system impacted system availability and required operator work-arounds to assure HPCI system operability. Repetitive equipment problems with the gland seal condenser level switch caused Unit 3 HPCI to be declared inoperable, and the alignment of the condensate storage tank once caused both HPCI systems to be declared inoperable.

The licensee's response to identified errors in the setpoints for system oil temperatures was poor. The licensee's original explanation of setpoint tolerances was incorrect, and the situation was not addressed until operators wrote a second PIF.

O3 Operations Procedures and Documentation

O3.1 (Units 2, 3) Control Room Rounds

a. Inspection Scope (71707)

The inspectors reviewed operator use of panel monitoring sheets.

b. Observations and Findings

The use of these sheets helped the licensee in detecting abnormal trends (e.g., the valved-out fuel pool cooling discussed in IR No. 50-237/97019; 50-249/97019 Section O3.1). The rounds sheets included a column of normal operating parameters. The inspectors noted that some values being recorded were not within the normal operating bands. For example, the torus temperature was 5°F above the listed value. Discussions with the operating staff indicated that the bands on the rounds sheets were not always the actual normal parameters, and that some operators did not routinely verify the parameters against the bands. The values were instead compared to values the operators knew from TS and operations procedures. The inspectors also noted some confusion about who performed the primary review of the parameters (US or nuclear station operators).

The inspectors considered the acceptance of rounds sheets with "normal" operating parameters that were not normal to be a poor practice. All operators interviewed were aware that the bands listed on the rounds sheets were not always the actual normal operating band. The operators explained that when the rounds sheets were created, the intent was to heighten panel monitoring and trending. The full "normal" bands for all equipment had not been entirely listed, and equipment outside the "normal" bands may still be within required bounds.

At the end of the inspection period, the licensee was evaluating improvements to the rounds sheets.

c. Conclusions

The use of panel monitoring rounds sheets helped operators identify trends and maintain panel awareness. However, the operators did not ensure that the rounds sheets contained the correct normal operating parameters for all equipment. The inspectors were concerned that acceptance of the incorrect bands reduced the rounds sheets' effectiveness.

O4 Operator Knowledge and Performance

O4.1 Unit 2 Automatic Reactor Trip

a. Inspection Scope (71707, 93702)

The inspectors reported to the main control room and observed operator performance following a Unit 2 automatic reactor trip (scram) that occurred December 23, 1997. The inspectors reviewed the significance of the event, performance of safety systems, and actions taken by the licensee. The inspectors also reviewed station logs, control room recorder indications, the scram investigation team's results, and assessed the functioning of the Plant Operations Review Committee (PORC) meeting held to approve a unit restart.

b. Observations and Findings

Before the reactor scram, the HPCI system was out of service and isolated due to a spurious full isolation that occurred on the previous day. All other emergency core cooling systems (ECCS) were in normal alignments.

Instrument maintenance department personnel were performing Dresden Instrument Surveillance (DIS) 0500-01, "Reactor Vessel High Pressure Scram Pressure Switch Calibration." Part of the surveillance resulted in actuation of the reactor protection system (RPS) Channel "B" half scram. This was expected. While the planned half-scram was actuated, an unexpected average power range monitor (APRM) high-high signal occurred, and actuated Channel A of RPS. This resulted in a full scram signal.

Operator Response

Operator response to the transient and performance during scram recovery were good. The inspectors observed good procedural usage by the operators, formal communications throughout the event, and effective command and control by the US. Unit 3 activities were reduced to limit distractions to the Unit 2 operators.

Equipment Response

All rods inserted, and the reactor automatically shut down. However, not all equipment responded ideally. The reactor feedwater level control system caused the reactor pressure vessel (RPV) level to increase above +48." This would have flooded the HPCI system's steam lines, but the HPCI system was already isolated. This item, and required operator compensatory actions to prevent a repeat occurrence, are discussed further in Section E1.2 of this report. The inspectors concluded that the actual safety consequences of this event were low.

Prompt Root Cause

The licensee formed a prompt root cause team to determine the immediate causes of the reactor trip. A formal root causes investigation was also assigned, but was not completed during this inspection period.

The immediate cause of the event was that LPRM 2D-24-41 spiked high, causing APRM 2 to spike high, which in turn generated a trip on RPS Channel "A." Since a trip on RPS Channel "B" half scram was already actuated due to testing, the RPS scram logic was satisfied and a full automatic reactor scram occurred.

General Electric (GE) service information letter (SIL) 500, issued October 23, 1989, discussed the phenomenon of LPRM spiking. The SIL stated that a "whisker" (buildup of uranium oxide) arcing in the detector caused spikes. The arcing typically eliminated the whisker. To prevent spikes, the GE SIL recommended that detector breakdown (current-voltage) tests be performed at specified intervals to look for whiskers in the detectors. The SIL also provided guidance on how to burn-off the whiskers to prevent spikes.

The licensee found that ComEd's Nuclear Fuel Services had reviewed the SIL, but did not require performance of all of the recommendations in the SIL. Instead, burn-offs were only performed on problem detectors. The licensee's investigation team concluded that the failure to perform all of the GE SIL recommendations directly contributed to the spike.

The inspectors assessed the PORC meeting held to review the prompt root causes and corrective actions prior to plant restart. The PORC thoroughly discussed the event, the investigation team's conclusions, and the recommended actions prior to restart. The PORC maintained an appropriate safety-focus during review of the prompt root cause.

c. Conclusion

The operator response to the automatic reactor trip was good. The inspectors concluded that the actual safety consequences of this event were low. Operator and plant equipment response were generally as expected for an automatic reactor trip from full power. The exception involved the response of the feedwater level control (FWLC) system; however, in this case there were no adverse consequences from the level overshoot since the HPCI system was already isolated for troubleshooting efforts.

The prompt root cause investigation team formed by the licensee performed a thorough review of the event and subsequent equipment problems. The inspectors concluded that the prompt root cause of the event was the failure to perform the actions identified in GE SIL 500 regarding LPRM spiking.

O4.2 (Unit 2) Operations Performance During Startup

a. Inspection Scope (71707)

The inspectors conducted observations of startup activities from forced outage D2F30.

b. Observations and Findings

During the Unit 2 startup, operations observed were performed in a careful and controlled manner. Good communications were evident, and the operators were knowledgeable of the plant conditions and issues. The crew performed correctly and maintained awareness of the plant status. The shift manager and US maintained correct command and control during the startup. The US held crew briefs as necessary, and directed entry into the correct abnormal procedures in response to several instances of double-notching control rods.

The startup and power ascension of Unit 2 were hampered by some minor equipment problems such as double-notching control rods. The inspectors concluded that the actions taken were appropriate to the symptoms and in accordance with plant procedures.

c. Conclusions

Operations personnel exhibited safe operating practices during the startup of Unit 2 that commenced on December 26. Crew briefs and heightened level of awareness briefs were informative, contingency actions were discussed, and peer checks were performed.

O4.3 Unit 3 HPCI Inoperability

a. Inspection Scope (71707)

The inspectors reviewed the operators' initial operability call for the HPCI system on December 29, 1997, after the low level switch in the gland seal leakoff (GSLO) condenser failed to stop the drain pump.

b. Observations and Findings

At 0234 on December 29, 1997, while performing DOP 2300-01, "Unit 2(3) HPCI System Standby Operation," Rev. 15, for the Unit 3 HPCI System, the operators started the GSLO pump to pump down the GSLO condenser hotwell as required by the procedure. The pump did not stop at the low level switch as designed but continued to pump down the GSLO condenser. The Unit 3 nuclear station operator (NSO) manually secured the pump. The US control room logs stated that operability was immediately discussed by the US, and a previous event was also considered. However, the US concluded that, for this event, the Unit 3 HPCI system was operable.

The operability issue was revisited later in the shift. An entry made at 0447 in the US log book showed that the US reviewed the surveillance tests, the UFSAR, emergency notification system (ENS) requirements, previous ENS calls made for the HPCI system, the historical limiting conditions for operation (LCO) logs, and the design basis documents to determine operability requirements. The US also discussed the issue with the on-call system engineer. The US again concluded that the HPCI system was operable.

The previous event occurred on September 5, 1997, and was discussed in LER 97-009-00/50-249. The Unit 3 HPCI system was declared inoperable during a surveillance test due to the failure of the GSLO condenser drain pump low level switch to shut off the pump at the required low level. This led to cavitation and air entrainment in the pump suction and air accumulation in the discharge pressure regulating valve sensing line.

The licensee continued review of HPCI system operability. Subsequently, the HPCI system was declared inoperable at 1945, December 29, 17 hours after the first symptoms. The inspectors concluded that, due to the similarity between this failure and the failure of September 5, the length of time was excessive.

c. Conclusion

Operator performance with respect to the initial operability call was weak. While the operators followed the station's administrative procedures for determining operability, sufficient data was available to support a more timely declaration of HPCI inoperability.

When operations declared the HPCI system inoperable, the staff entered the appropriate TS limiting conditions for operation from the time of the operability determination, but not from the actual first symptom. The inspector concluded that not entering the limiting condition retroactively was not the most conservative decision. Information was available to link the start of the HPCI system problem to the original failure of the GSLO pump to stop automatically at the GSLO condenser hotwell low level.

This was of concern to the inspectors because of its similarity to a recent issue regarding the standby liquid control (SBLC) system. In IR 50-237/97024; 50-249/97024, the NRC documented an instance in which operations failed to declare the SBLC system inoperable upon receipt of valid control room alarms.

O4.4 (Units 2, 3) Operator Knowledge of HPCI System Parameters

a. Inspection Scope (71707)

The inspectors questioned operators about HPCI system indications. The questions were limited to operator knowledge of the actual HPCI parameters present on the units.

b. Observations and Findings

The Nuclear Station Operators (NSOs) were generally aware of the HPCI initiation and isolation signals, the valve interlocks and the operating parameters (temperature and pressure limitations) of the HPCI turbine lube oil system.

One exception to this occurred during questioning of one Unit 2 NSO. During the walkdown the inspectors noted that all HPCI system turbine lube oil temperature computer monitor points on Control Panel 902-3 indicated between 92 to 95°F. The inspectors then questioned the NSO on temperature limits while the HPCI system was in standby operation and the expected temperature bandwidth for HPCI turbine lube oil temperature when he performed his control board walkdown. The NSO answered by stating that he was not aware of any temperature limitations of the HPCI turbine lube oil system while in standby operations. Both DOS 2300-03 and DOS 2300-07 required HPCI oil cooler discharge temperature be greater than 96°F. The manufacturer's manuals cautioned that bearing inlet temperatures outside of limits should be avoided to prevent damaging the bearings due to poor oil circulation.

After a discussion of concerns with the inspectors, the US ordered the NSO to place the HPCI turbine on the turning gear since the oil pump adds a significant amount of heat to the oil. The US also initiated an AR to calibrate the HPCI sump heater to a higher temperature to ensure that HPCI oil temperatures are maintained within the design temperatures. Instrument Maintenance Department (IMD) personnel adjusted the controller for the HPCI sump heater on December 23, 1997.

The inspectors noted that control room hourly rounds sheets did not include sump oil temperatures. The licensee was considering adding these parameters to the rounds sheets.

c. Conclusions

Operators generally were knowledgeable of the HPCI system parameters, settings, and requirements. The inspectors identified one instance where the requirements were not known.

O7 Quality Assurance in Operations

O7.1 Failure to Follow Integrated Reporting Program Procedure

a. Inspection Scope (71707, 40500)

The inspectors reviewed the licensee's corrective actions procedure, Nuclear Station Work Procedure (NSWP) A-15, "Integrated Reporting Program," to determine the station's compliance with the stated requirements. The inspectors reviewed whether the PIF process was properly followed after PIFs were submitted.

b. Observations and Findings

The licensee documented problems and non-conforming conditions via use of PIFs. Licensee Procedure NSWP-A-15, "ComEd Nuclear Division Integrated Reporting Program," Rev. 1, required a feedback form be provided to the originator of the PIF. The inspectors identified that the licensee was not sending the required feedback forms to the PIF originators in accordance with NSWP-A-15.

The licensee was required by TS 6.8.A to implement the applicable procedures recommended in Appendix A of RG 1.33, Rev. 2, February 1978. Procedures for administrative controls were recommended in RG 1.33. Contrary to the above, the licensee failed to implement the requirement of NSWP-A-15 to provide feedback to PIF originators. **This was a violation of TS 6.8.A (VIO 50-237/97028-01 (DRP); 50-249/97028-01 (DRP)).**

Subsequent to the inspectors identification of the failure to initiate the required feedback forms, but prior to the inspectors' presentation of the finding to licensee management, the licensee independently identified that the PIF process was not being followed with respect to the feedback forms. The licensee's Quality and Safety Assessment (Q&SA) organization identified that the procedure was not being followed across the board with respect to the feedback issue. The Q&SA department concluded that when the new requirement was put into the NSWP, the Dresden Staff did not realize the new requirement and did not change local practices to comply. On December 3, 1997, the Q&SA department initiated PIF D1997-08096 to document that the required feedback forms were not being distributed to the originators as required by NSWP A-15.

The licensee commenced generating the required feedback forms following identification of the issue and provided several examples to the inspectors for review. The licensee entered the procedure adherence concern, via PIF D1997-08096, into the corrective action process for long term resolution.

c. Conclusion

The licensee failed to follow the procedural requirements to provide feedback to PIF originators. After the inspectors' review of the process, the licensee independently identified this procedural adherence concern and entered it into the corrective action program. The licensee met the procedural requirements before the end of the inspection period.

II. Maintenance

M1 Conduct of Maintenance

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Plant Material Condition

a. Inspection Scope (62707, 37551)

The inspectors noted that several material condition issues and self-revealing equipment failures during the inspection period required plant personnel to take prompt action. The inspectors reviewed the failures to determine the effect on plant safety.

b. Observations and Findings

- Control Rod Drive (CRD) F1 Unexpected Insertion:

  On December 6, 1997, during the performance of DOS 0500-03, "APRM Rod Block and Scram," functional test, CRD 22-03 (F-1) unexpectedly scrammed to position 00. The single-rod scram occurred approximately 15 seconds after receiving an RPS Channel 'B' half scram signal. The licensee performed detailed troubleshooting of the scram solenoid pilot valve (SSPV) and the RPS/SSPV logic. The licensee concluded in Prompt Investigation Report No. 0005576052 that rod F-1 had not exhibited any specific characteristics of a degraded or failed SSPV. Despite this, the licensee concluded that based on previous licensee and industry experience the resultant single rod scram was consistent with that of a degraded or failed SSPV. The licensee replaced the SSPV, successfully performed scram functional testing, and placed rod F-1 back in service.

- Unit 3 Torus Cooling Test Valve Failure to Operate:

  On December 1, 1997, the torus cooling outboard test valve failed to operate on demand, resulting in a potential for diversion of cooling flow from the reactor in the event of a design basis accident. The licensee determined that the cause of the valve failure was due to a faulty auxiliary contact on the open contactor for motor operated valve MOV 3-1501-38B. The licensee replaced the auxiliary contact. The faulty component was relatively new, and the licensee could not immediately determine the reason for the failure.

- Unit 2 HPCI Full Isolation:

  During performance of DIS 2300-03, "HPCI Low Pressure Isolation Channel Functional Test," the HPCI system received a Group IV isolation and HPCI steam line inboard and outboard primary containment isolation valves (2-2301-4 and 5) went closed. The licensee could not determine the cause of isolation during inspection and troubleshooting efforts, but replaced the relays that completed the isolation logic (2391-02C and 2391-02D). The licensee sent the relays to the vendors for analysis.

- 2A Reactor Recirculation Motor Generator Erratic Operation:

  On December 6, 1997, the Unit 2 control room operators received a Recirc Pump Mismatch alarm. The 2A recirculation pump ran back from approximately 49 percent pump speed to approximately 39 percent pump speed and appeared to be running back up to the original speed when the unit operator locked-up the scoop tube. Despite detailed testing and troubleshooting efforts, the licensee was unable to determine the cause of the event. The licensee installed a temporary recorder on the pump speed control circuitry to monitor for any future possible abnormalities.

- 3A Offgas Fire:

  The 3A steam jet air ejector (SJAE) train did not work properly and was susceptible to offgas fires. In the past, the licensee repaired and replaced portions of the Unit 3 offgas system to restore the 3A train. However, during this inspection period, the licensee experienced an offgas fire on December 6, 1997, while the operating crew was adjusting the 3A recombiner booster/dilution steam pressure using the manual bypass valve around the inoperative, isolated pressure control valve. The licensee fixed various leaks and attempted to fine tune the booster jet pressure control valve (which was identified as oscillating). However, on January 13, 1998, when the licensee again tried to bring the 3A train in service, another offgas fire occurred. At the end of the inspection period, the licensee was evaluating if modifications to the system were necessary.

- 3B Reactor Water Clean Up (RWCU) Demineralizer High D/P:

  The station experienced repeated difficulties in placing the 3B RWCU demineralizer in service. The operators consistently received indication of a high differential pressure across the bed when the unit was placed on line. The operators had to perform multiple power reductions/ascensions to support taking the demineralizer out of service for maintenance and returning it to service once the maintenance efforts were complete. At the end of the inspection period, the licensee was still engaged in troubleshooting efforts to restore the 3B demineralizer.

- Unit 3 HPCI Inoperability:

  On December 29, 1997, while placing the HPCI system in standby, operators started the GSLO pump to pump down the GSLO condenser hotwell. The pump failed to stop when it should have. This caused air entrainment in the pump suction and air accumulation in the discharge pressure regulating valve sensing line, which then caused a reduction in the pump capacity. This event was similar to a September 5 event where the HPCI system GSLO condenser pump failed to stop on the low level switch. Troubleshooting and inspection of the low level switch in the GSLO condenser revealed no abnormalities with the low level switch. Further inspection efforts of the HPCI GSLO condenser revealed that linkages on the high level switch were not intact. This event was the third event where the licensee's HPCI System GSLO pump failed to operate properly due to level switches malfunctioning (Ref. LERs 97-009/50-249 and 97-013/50-237).

- Unit 2 Feedwater Level Control System:

  The response of the feedwater level control (FWLC) system caused reactor level to overshoot following the automatic trip of the reactor on December 23, 1997. The HPCI steam line would have flooded with water had not HPCI already been isolated for troubleshooting. The FWLC system presented an additional operator work-around due to the required operator compensatory actions following a reactor trip on Unit 2.

c. Conclusion

Collectively, the above issues represented challenges and distractions for operators and other plant staff. The issues especially represented a burden to operators who had either to respond to the original event, or to take additional compensatory actions.

The inspectors were also concerned with the licensee's ability to resolve the issues effectively and eliminate the deficiency. In some cases, the plant staff knew what happened (and took appropriate short term corrective action) but did not know the root cause of why the problem occurred.

M4 Maintenance Staff Knowledge and Performance

M4.1 (Unit 3) 125 V Battery Work

a. Inspection Scope (62707)

The inspectors reviewed an error performed during battery testing that caused the station to enter a two-hour dual shutdown LCO. The inspectors also reviewed the documentation of the subsequent battery work.

b. Observation and Findings

Equipment Operation Outside of Procedure

On December 13, workers from the electrical maintenance department (EMD) were authorized by operators to place the Unit 3 125 VDC charger on equalize per WR 970131667. At 0818, shortly after work started, the control room unexpectedly received the 125 VDC battery undervoltage and charger trouble alarms, followed by battery high discharge alarms. The control room immediately dispatched a high-voltage operator (HVO) to investigate. The HVO reported that the No. 3 125 VDC charger had tripped. The voltage on the batteries had rapidly dropped to 117 VDC, then more slowly to 115 VDC. The HVO aligned the 3A charger and restored voltage to normal by 0822.

The electrical maintenance department (EMD) supervisor who was present at the batteries reported that he had manipulated the battery charger without a procedure in hand.

The inspectors discussed the actions with the EMD supervisor. The supervisor stated his workers were having difficulty getting readings, so the supervisor commenced troubleshooting. He went to the charger and noted that the charger's toggle switch was in float. The supervisor believed it should have been in equalize, so he immediately changed it. He did so without any procedures, without any other workers present, and without verifying the response to his actions. The toggle switch broke and caused the charger to trip off, but since the supervisor did not wait to observe the expected response, he did not realize this.

The supervisor told his worker what he had done, and the workers in the room informed the supervisor that his actions were incorrect. The HVO responding to the charger trouble alarms then arrived at the scene, and the supervisor informed the HVO and operations of the incorrect actions.

The inspector questioned the EMD supervisor about what, if any, distractions were present. The supervisor stated that no distractions were present, and that he had just been concentrating on troubleshooting so much that he had failed to maintain his role as a supervisor, and that he had failed to adhere to the requirements for procedural use.

The EMD supervisor did not perform correctly when he manipulated equipment. The WR used a "Category 1" procedure, and DAP 09-13 defined the level of use for a Category 1 procedure as "Continuous." Also, the supervisor should not have touched the equipment in his oversight role.

Dresden TS 6.8.A.1. required that written procedures be implemented covering the activities recommended in Appendix A of RG 1.33, Revision 2, February 1978. The guide recommended procedures covering maintenance work. Dresden Administrative Procedure (DAP) 09-13, "Procedural Adherence," Rev. 06, required continuous use of a Category 1 procedure. Contrary to this, on December 13, licensee personnel performed work without continuously using the appropriate Category 1 procedure. As a consequence, licensee personnel incorrectly manipulated equipment. The switch failed, causing the 125 VDC battery charger to trip. **This was a violation (VIO 50-237/97028-02 (DRP); 50-249/97028-02 (DRP)).**

Immediate Licensee Response

The licensee immediately removed the supervisor from duty and took other actions in accordance with established management principles. The supervisor was tasked with performing an "Apparent Cause Evaluation" and performing other training and remediation.

The licensee assigned another EMD supervisor to complete the initial work request.

Documentation Errors in Rework

The inspectors reviewed the completed work request (WR 970131667) and noted several errors in how the work request was filled out.

First, it did not refer to the incorrect manipulation, and the "work progression sign-off" had been marked as "N/A." The use of the sign-off was at the discretion of the supervisor, so it was not a violation to "N/A" the sign-off. When the battery was tripped and the work was stopped on December 13, no one chose to fill in the work progression sign-off, so the WR did not record why work was stopped, nor who stopped it.

Second, the inspectors noted that the Steps I.1 and I.2 of the procedure were initialed by the second supervisor as "CM 12/13/97" for conditions met on December 13. The inspector noted that the second supervisor did not have the assignment on December 13. Also, Step I.2. stated, "Document that Prerequisites are completed on Data Sheet 1," but the second supervisor had marked Data Sheet 1 as "N/A 12/18/97." For Step I.2, the conditions clearly were not met, and the "N/A" should not have been used.

The inspectors discussed the concerns with the second supervisor. The supervisor stated that he had used "CM" for the first two steps after verifying that the prerequisites were complete, and that the intent date of "12/13/97" was to indicate the day the conditions were met. The second supervisor stated that he did not review Data Sheet 1 before marking Step 1.2 as "CM."

Procedure 09-13 also stated that "condition met (C/M) should be entered if an individual finds that the requirements of a procedure step are already satisfied." The inspector noted that the requirements of Procedure Step I.2 were not met, in that the data sheet was not filled out.

The use of initials by each line in the procedures was required by the EMD superintendent, but not by Dresden administrative procedures. Incorrectly using "CM" was therefore not a violation. The use of "CM" led to a failure to document completion of prerequisites on Data Sheet 1, and therefore the use of "CM" led to a failure to follow procedures. No violation is being issued for this example of failure to follow procedures because the circumstances would be expected to be enveloped by the violation being issued for the initial failure to follow procedures on the battery.

c. Conclusions

On December 13, work performed without referencing a required procedure, combined with material condition, tripped off the Unit 3 charger and placed both units unexpectedly into a two-hour LCO. The subsequent follow up work was not performed in accordance with station administrative procedures. Specifically, the "CM" sign off was used when a condition had not been met.

Section O8.1 of Dresden IR 50-237/97024; 50-249/97024 documented a case where the incorrect use of "CM" led to the high pressure coolant injection (HPCI) system being unavailable. The inspectors were concerned that the second example of "CM" being used incorrectly occurred.

M8 Miscellaneous Maintenance Issues

M8.1 Tracking of Rework (62707)

In Section E8.2 of Inspection Report 97019, the inspectors discussed rework tracking. The inspectors noted that the licensee's methodology was recently changed. To perform an assessment of rework, the inspectors kept a list of selected items that were known to be rework, then checked if the items were captured into rework tracking. The results revealed that one of five items was not captured. The licensee was investigating why it wasn't tracked. Based on the large number of items that were captured, though not specifically tracked by the inspectors, the inspectors concluded that one identified anomaly did not invalidate the total tracking of rework, but was cause for the inspectors to expand the sample size.

The inspectors also noted that the 125 VDC battery work discussed in Section M4.1 of this report was not originally identified as rework. The inspectors noted that assigning a second supervisor to become familiar with and execute work was unnecessary repetition of work caused by inadequate performance of the original task, and was therefore rework. The inspectors discussed this observation with the licensee's rework coordinator.

III. Engineering

E1 Conduct of Engineering

E1.1 Root Cause Investigation of Unit 2 Automatic Reactor Trip

a. Inspection Scope (37551)

The inspectors discussed the event's root cause with the licensee's investigation team, interviewed individual engineers associated with the investigation, and attended the PORC meeting where the team presented their results to licensee management.

b. Observations and Findings

The event response team's charter directed the team to determine the root cause of the event, evaluate the plant's response, and evaluate the suitability for restart.

The inspectors determined that the team was self-critical in evaluating the root cause and did not hesitate to state that the utility's past actions in response to the GE SIL were not consistent with current policies and practices. After the scram, the station experienced several more LPRM half scrams. The half scrams occurred on Unit 3 and involved detectors that had not previously exhibited spiking. For example, Unit 3 operators received an unexpected Channel "B" half scram on January 5, 1998, due to a spike on LPRM 1D-24-49. On January 7, 1998, a Channel "B" half scram occurred due to spiking on LPRM 32-57A. The station re-reviewed the SIL and implemented new actions to address LPRM spiking. Before the end of the inspection period, the station worked around the clock to perform the current-voltage curves for all LPRMs that fed the APRMs. Results of the tests were used to determine the need for capacitance discharge ("whisker burns") tests on LPRMs, that exhibited the potential for spiking. At the end of the inspection period, the licensee was working on a schedule to complete testing on the remaining LPRMs, as well as future long term actions to address the issue of LPRM spiking.

The inspectors also reviewed the team's assessment of the plant equipment response following the scram. Except for the FWLC system response (discussed in Section E1.2), plant equipment functioned as expected with only minor anomalies noted. The team appropriately dispositioned these items.

c. <u>Conclusion</u>

The inspectors concluded that the licensee's root cause team performed a thorough investigation of the event, the root cause, and equipment response following the reactor scram. The licensee's team concluded that the root cause of the event was the failure to perform the actions identified in GE SIL 500 regarding LPRM spiking. The inspectors agreed with this conclusion.

E1.2 <u>Response of the FWLC System Following Unit 2 Automatic Reactor Trip</u>

a. <u>Inspection Scope (37551)</u>

The response of the FWLC system caused reactor vessel water level to overshoot following the scram. The overshoot would have flooded the HPCI steam line had HPCI not been already isolated for troubleshooting purposes. The inspectors reviewed the licensee's investigation into the issue and proposed resolution prior to restart.

b. <u>Observations and Findings</u>

The inspectors noted expected reactor vessel water level response immediately following the reactor trip. Vessel level dropped to approximately -4" (normal level is +30") due to shrink; this response was normal and expected. However, upon level recovery reactor water level rose above +60" and was about 3" above the lower level of the HPCI steam lines. Per design, at this level the HPCI system would have tripped, but not physically isolated. The HPCI steam line would have flooded had the system not already been isolated for maintenance purposes. The configuration of the steam supply piping was such that the water would have remained trapped in the line after vessel level dropped back below the trip setpoint.

The response of the FWLC system was as designed. However, in this case, appropriate equipment response and appropriate post-trip operator response did not prevent a reactor water level overshoot and potential filling of the HPCI steam lines. Upon receipt of reactor scram and level drop from 30" (normal) to +2", "setpoint setdown" occurs. During setpoint setdown, the FWLC system changes the required level setpoint and ramp rate of the feedwater regulating valve (FRV) so that upon level recovery, water level does not overshoot and raise the vessel level too high. However, the receipt of "bad quality" data introduces a time delay in the initiation of setpoint setdown. Bad quality data was defined as data that was outside the range of the narrow range level indicator scale; on Unit 2 the narrow range level indicators read from 0" to +60". Therefore, when reactor water level dropped to approximately -4", the FWLC system logic received "bad quality" data and a time delay (between three to seven seconds) occurred before setpoint setdown was initiated. This time delay was sufficient to prevent the FWLC system from responding quickly enough to prevent a level overshoot. Since the FWLC system and post scram water level drop responses were normal and as expected, all Unit 2 scrams from full power have the potential to result in a level overshoot with the corresponding effect of putting water in the HPCI steam line.

Several differences existed between the Unit 2 and Unit 3 FWLC systems that would have prevented a level overshoot on Unit 3. On Unit 3, the FWLC system was set up in three element control, whereas on Unit 2 the system was set up in single element control. The Unit 3 narrow range level transmitters are scaled from -60" to +60" which would prevent the receipt of "bad quality" level data following a reactor trip. Also on Unit 3, when a reactor scram signal is received, the system immediately goes into setpoint setdown that aids in vessel level recovery efforts. The licensee's root cause investigation team concluded that these factors would prevent a similar level overshoot from occurring on Unit 3. The inspectors reviewed the team's results and did not disagree with this conclusion.

The licensee's resolution to address the response of the FWLC system included both long term and short term corrective actions. The licensee plans to modify the Unit 2 FWLC system during the upcoming refueling outage to make it similar to the system on Unit 3. The licensee planned to rely on operator compensatory actions for the immediate short term corrective actions. Upon receipt of a scram signal, operators would be required to analyze feedwater system response and trip off one running feedwater pump once level turned and started to rise following a reactor trip. In addition to tripping a reactor feedwater pump, operators would also be required to take manual control of the feedwater regulating valves to ensure that level would not overshoot and flood steam lines. The inspectors reviewed post event charts and concluded that these actions would be required within the first ten seconds following the reactor scram. The inspectors were concerned that the station was relying on operator action to prevent water intrusion into HPCI steam lines following a reactor scram.

c. <u>Conclusion</u>

The FWLC system response presented a potential challenge to the operators following the reactor scram. The compensatory actions that operators are required to take following a scram on Unit 2 constitute an additional operator work-around. Pending permanent resolution of the Unit 2 FWLC system issues, the station was relying on operator intervention following a scram to prevent water intrusion into HPCI steam lines.

E2 Engineering Support of Facilities and Equipment

E2.1 (Units 2, 3) Operability Evaluations

a. Inspection Scope (71707, 37551)

The inspectors reviewed recent operability evaluations. Compliance with the requirements of DAP 07-31, Rev. 07, "Operability Determinations," and the impact on plant operations were considered. A detailed evaluation of any engineering calculations used to make the final determinations was not performed.

Operability determinations reviewed included:

97-105	"Personnel Air Lock Equalizing Valve - Concern Identified with Material of Seals"
97-107	"Concern of Potential Vortexing in CSTs"
97-108	"Failure of the Unit 2 125 VDC Alternate Battery to Maintain 105 VDC at Bus under D.B.A. Condition"
97-109	"HPCI Small Bore Lines Do Not Meet UFSAR Design Criteria"
97-110	"Reactor Building Superstructure Seismic Requirements"
97-112	"Post-LOCA Reactor Building Temperatures Beyond UFSAR Limit of 104°F"

b. Observations and Findings

The operability determinations reached the following conclusions:

97-105 - Operable, but degraded. The concern was that if exposed to design basis accident (DBA) conditions of 334°F and 63 psia, the airlock equalizing valves' seats may soften and cause a leak. Based on calculations, the licensee determined that the outer door would probably not be affected. Corrective action required was to schedule replacement of equalizing valves on all airlock doors during D2R15 and D3R15.

97-107 - Operable, but degraded. The concern was that vortexing may occur and cause air entrainment in HPCI system. Calculations showed that aligning the HPCI system suctions to both condensate storage tanks (CSTs) would be sufficient to prevent vortexing. Also, postulated breaks inside containment resulted in a swap to torus suction before reaching CST vortexing. Postulated breaks outside of containment challenged the CST supply. Corrective actions included realigning the CST supplies and evaluating changing the CST low level switches.

97-108 - No concern exists. The concern was that the 1000-foot cable-run from the Unit 2 125 VDC alternate battery to the distribution panel resulted in a previously unconsidered voltage drop. Engineering concluded that based on latest actual battery surveillance tests and calculations, no concern exists. Although the battery currently met its requirements, engineering added a request to add additional cells to address expected margin reduction due to aging.

97-109 - Operable but degraded. The concern was that several Unit 2 and Unit 3 HPCI system lines were inadequately supported to meet design basis requirements. The lines included drain pot discharge lines and the gland seal condenser discharge line to the torus. The licensee concluded that the lines were operable because the lines met the requirements of ComEd Nuclear Engineering Standard (NES) No. NES-MS-03.2, "Evaluation of Discrepant Piping and Support Systems," Rev. 0, and the stresses were less than twice yield stress. Corrective action planned was to reevaluate the piping and determine how to restore it to design limits.

97-110 - Operable but degraded. The concern was that calculations for the reactor building crane being loaded during a safe shutdown earthquake (SSE) were never performed. Engineering concluded that the 125-ton crane must be limited to 12.5 tons based on determining that the additional 12.5 tons was insignificant compared with the mass of the crane and trolley. For corrective actions, the licensee planned to determine what commitments existed regarding the required analysis, and, if necessary, perform a detailed analysis for SSE while the maximum crane load was lifted.

97-112 - Operable but degraded. The concern was that recent calculations showed that the post-accident temperatures of the reactor building were generally from 120 to 160°F, whereas the UFSAR limit was 104°F. Engineering concluded that as long as the outside air 30-day average temperature remained below 44°F or 68°F (the temperature depended on other compensatory actions), then the safety-related equipment will function.

Corrective actions included direction to shut down the non-accident unit and other actions to increase reactor building cooling, and re-calculation of temperatures.

Operability determinations were governed by DAP 07-31, Rev. 07, "Operability Determinations." The performance of the reviewed operability determinations met DAP 07-31. The engineering used to make operability conclusions appeared reasonable.

The operability determinations reflect the status of the design basis at Dresden. The licensee did not have supporting calculations for some systems. As the calculations are performed, some calculations raise operability concerns. The licensee was dealing with these issues appropriately, even when the compensatory or corrective actions were significant.

The licensee used the Dresden Engineering Assurance Group (DEAG) to review the operability determinations. No PIFs or rework resulted from the DEAG's reviews of determinations 97-107, 97-109, and 97-110. The DEAG did comment on determination 97-110 regarding the need to provide a complete basis for corrective actions. The DAEG review identified "major problems" with the basis for operability and the corrective actions related to determination 97-106, "Lack of vent valves on CCSW suction headers, repriming, and leakage criteria," and generated PIF No. D1997-08537. Note that 97-106 was not discussed in this report because it was reviewed in Dresden Inspection Report No. 50-237/97021; 59-249/97021. The DEAG did not review 97-108 because no concern was identified.

c. Conclusions

The operability evaluations appeared to meet licensee requirements. The evaluations were reasonable and provided adequate bases for the conclusions.

The scope of the evaluations reflected the current state of the design of Dresden Station, in that several evaluations resulted from performing calculations to replace missing or never-performed calculations.

E4 Engineering Staff Knowledge and Performance

E4.1 (Unit 3) Engineering Evaluation of Batteries

a. Inspection Scope (37551)

The inspectors assessed the engineering response to the December 13 event in which the Unit 3 125 V battery charger was inadvertently tripped.

b. Observations and Findings

As discussed in Section M4.1, the Unit 3 battery charger was tripped inadvertently during maintenance. The control room logs and the PIFs written about the event recorded that the voltage on the batteries had dropped to 115 VDC. The inspectors asked the licensee if 115 VDC was the expected value for the 125 VDC batteries.

The licensee had not previously considered the battery's response, because the battery remained above 105 VDC and passed its last surveillance test.

However, a few days after the initial question, the licensee compared the performance with a vendor-supplied graph of the discharge characteristics of the battery and concluded that 115 VDC was the expected voltage given the loads on the battery.

c. Conclusions

The licensee had not performed a detailed reviewed the battery's performance. However, the licensee eventually was able to show that the battery behaved as it should have.

IV. Plant Support Areas

Radiological Protection and Chemistry (RP&C)

R4 Staff Knowledge and Performance in RP&C

R4.1 (Units 2, 3) Treatment of Contaminated Area Boundaries

a. Inspection Scope (71750)

The inspectors observed worker performance around contamination area boundaries with respect to the licensee's RP&C procedures.

b. Observations and Findings

Workers generally respected the boundaries placed to control contaminated areas. The placement of step-off pads and boundaries provided sufficient room for workers to work. Equipment was generally staged or stored correctly and did not present a contamination control hazard.

On December 19, the inspectors identified that a white hose that crossed a step-off pad in the Unit 2 east torus basement area was not secured at the contamination boundary. The inspectors informed the licensee and the licensee secured the hose. The licensee issued PIF D1977-08731 to track the issue, and determined that the hose had originally been placed to support work on the east low pressure coolant injection (LPCI) system corner room sumps. The work was completed, but the 2A east corner room sump was still not working properly since repairs, so the hose was staged as part of a contingency in case the 2B east corner room sump failed. The licensee also found that the equipment in use tag on the hose was not up to date.

A search of PIFs revealed four other examples of untaped or improperly marked hoses (ref. PIFs No. D1997-07363, -07396, -08390, 08607). This was a marked increase from the number of radiation control PIFs written during the previous months.

Procedure DAP 03-07, Rev. 09, "Control of the service air and domestic water systems and hoses for general station use," Step F.3.e. stated, "IF a RED, WHITE, OR CLEAR hose must cross the boundary between a contaminated area AND a non-contaminated area, THEN the hose must be secured at the boundary using Radioactive Materials Tape." **The failure to secure the hose was a violation of DAP 03-07 (VIO 50-237/97028-03 (DRP); 50-249/97028-03 (DRP)).**

The inspectors also saw other examples of poor control of contamination boundaries. For example, a worker mopping a contaminated area allowed the bucket to cross the contamination boundary, and other workers placed equipment and work instructions on contamination boundaries.

c. Conclusions

The setup and control of contaminated areas and work in contaminated areas were usually correct.

The inspectors identified one example of an improperly secured hose that crossed a contamination boundary. The hose had been staged in response to a poorly performing sump pump.

The safety significance of these issues was minor. However, the inspectors were concerned with the lack of attention to detail exhibited by the plant staff to radiation controls, and that the PIF record showed this to be an emergent trend.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 12, 1998. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X3 Management Meeting Summary

On December 22, the NRC Region III Regional Administrator and the Director of the Division of Reactor Projects visited the site, met with senior licensee management, and discussed current licensee performance.

PARTIAL LIST OF PERSONS CONTACTED

G. Abrel, ComEd NRC Coordinator
D. Ambler, Regulatory Assurance Supervisor (Acting)
P. Bernice, Ops Staff
T. Bezouska, Site Vice President Staff Assistant
R. Fisher, Maintenance Manager
R. Freeman, Site Engineering Manager.
M. Heffley, Site Vice President
C. Howland, Radiation Protection Manager
L. Jordan, Training Supervisor (Acting)
W. Liscomb, Site Vice President Staff
P. Stafford, Station Manager (Former Outage/Work Control Manager)
D. Willis, EMD Superintendent
D. Winchester, Q&SA Manager

LIST OF INSPECTION PROCEDURES USED

Inspection Module:	71707	Operational Safety Verification
Inspection Module:	83822	Radiation Protection
Inspection Module:	62707	Maintenance
Inspection Module:	61726	Surveillance Observations
Inspection Module:	40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
Inspection Module:	93702	Prompt On-Site Response to Events at Operating Power Reactors
Inspection Module:	37551	On-Site Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237; 249/97028-01	VIO	failure to follow PIF process
50-237; 249/97028-02	VIO	failure to use procedures
50-237; 249/97028-03	VIO	failure to follow radiation protection procedures

Closed

None

Discussed

None

LIST OF ACRONYMS USED

DAN	Dresden Annunciator Procedure
DAP	Dresden Administrative Procedure
DATR	Dresden Administrative Technical Requirement
DEOP	Dresden Emergency Operating Procedure
DGA	Dresden General Abnormal Procedure
DOA	Dresden System Operating Abnormal Procedure
DOP	Dresden System Operating Procedure
EOPR	Engineering Operational Planning/Troubleshooting Report
FWLC	Feedwater Level Control
HPCI	High Pressure Coolant Injection
IFI	Inspection Followup Item
IPE	Individual Plant Evaluation
IR	Inspection Report
ISEG	Independent Site Engineering Group
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
NCV	Non-Cited Violation
NLO	Non-licensed Operator
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSO	Nuclear Station Operator
NSWP	Nuclear Station Work Procedure
OE	Office of Enforcement
OI	Office of Investigations
OOS	Out-of-Service
PIF	Problem Identification Form
PORC	Plant Operations Review Committee
RUFSAR	Revised Updated Final Safety Analysis Report
Q&SA	Quality and Safety Assessment
QC	Quality Control
TS	Technical Specification
US	Unit Supervisor
VIO	Violation
WEC	Work Execution Center
WR	Work Request