U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/93034(DRP); 50-249/93034(DRP)

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

Licensee: Commonwealth Edison Company
Opus West III
1400 Opus Place - Suite 300
Downers Grove, IL 60515

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

Inspection At: Morris, IL

Inspection Conducted: November 30, 1993 through January 10, 1994

Inspectors: M. Leach
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Approved By: P. L. Hiland, Chief P. L. Hiland 1/26/94
Reactor Projects Section 1B Date

Inspection Summary

Inspection from November 30, 1993 through January 10, 1994 (Report Nos. 50-237/93034(DRP); 50-249/93034(DRP))

Areas Inspected: Routine, unannounced resident inspection of operational safety verification and engineered safety feature (ESF) system walkdown; maintenance and surveillance observations; engineering and technical support observations; plant support observations; safety assessment and quality verification; licensee action on previous inspection findings; and licensee event report review.

Results: Of the seven areas inspected, no violations or deviations were identified in five areas. One violation for failure to follow a 1983 Order is discussed in paragraph 5. One violation for failure to take adequate corrective actions in regards to securing portable equipment is discussed in paragraph 7.

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Assessment of Plant Operations

The operators showed good attentiveness to the control room panels. The operators responded promptly to the Unit 2 loss of annunciators and the Unit 3 feedwater level oscillations events. Operator involvement in reducing personnel errors was considered positive. Management involvement in correcting licensee identified deficiencies in the emergency procedure program was weak.

Assessment of Maintenance and Surveillance

Numerous failures of reactor water level switches within the past year indicated slow licensee action to resolve this issue. The backlog of corrective non-outage work request continued to increase. The inspectors will monitor the licensee's actions to reduce the backlog. The licensee's preparation for the Unit 3 refueling outage was considered a strength.

Assessment of Engineering and Technical Support

The identification of the improper drywell and torus venting practices by engineering personnel was good. The licensee's response to the Appendix J untested piping was appropriate. The failure to follow an Order was indicative of a continuing problem to assess the impact of plant changes on previous NRC commitments.

Assessment of Plant Support

The licensee quickly communicated potential electronic dosimetry problems to station personnel. The licensee's response and initial investigation into contaminated oils found outside of radiologically controlled areas was good.

Assessment of Safety Assessment and Quality Verification

The licensee's corrective actions for a previous violation were ineffective in eliminating unsecured equipment in the plant. The licensee failed to identify the true problem in two level 4 investigations. The event screening committee did not ensure that the problem identification forms were appropriately evaluated.

DETAILS

1. Persons Contacted

Licensee Personnel

* M. Lyster, Site Vice President
  G. Spedl, Manager, Dresden Station
  D. Ambler, Executive Assistant to the Site Vice President
  E. Carroll, Chemistry Supervisor
* R. Flahive, Technical Services Superintendent
* L. Jordan, Health Physics Supervisor
  M. Korchynsky, Senior Operating Engineer
  J. Kotowski, Operations Manager
* G. Kusnik, Quality Control Supervisor
* S. Lawson, Operating Engineer
* H. Massin, Engineering Manager
* T. O'Connor, Maintenance Superintendent
* R. Radke, Services Superintendent
* S. Reece-Koenig, Performance Assistant Administrator
  R. Robey, Director, Site Quality Verification
* J. Shields, Regulatory Assurance Supervisor
* R. Speroff, Operating Engineer
  R. Stobert, Operating Engineer
  M. Strait, Technical Staff Supervisor
  B. Viehl, Nuclear Engineering Design Supervisor
* R. Wroblewski, NRC Coordinator

NRC Personnel

* C. Gill, Reactor Inspector
* G. Replogle, Reactor Inspector
* W. Shafer, Chief, Division of Reactor Safety Section, Maintenance and Outage Section

* Indicates persons present at the exit interview on January 10, 1994.

The inspectors also contacted other licensee personnel including members of the operating, maintenance, security, and engineering staff.

2. Summary of Operations

Unit 2

The unit operated at power levels up to 99% power. The unit was derated due to feedwater flow nozzle calibration discrepancies as discussed in Inspection Report 50-237/93029. On December 7, 1993, operators reduced power to 50% power to facilitate repairs on the 2B main steam isolation valve position indication. On December 29, operators again reduced power to isolate one steam tunnel area (X-area) cooler. Operation continued near 99% power for the remainder of the inspection period.

Unit 3

The unit continued coasting down throughout the period.

No violations or deviations were identified.

3. Plant Operations (71707, 71710 & 93702)

The inspectors verified that the facility was operated in conformance with the licenses and regulatory requirements and that the licensee's management control system was effectively carrying out its responsibilities for safe operation. During tours of accessible areas of the plant, the inspectors made note of general plant and equipment conditions, including control of activities in progress.

On a sampling basis the inspectors observed control room staffing and coordination of plant activities, observed operator adherence with procedures and technical specifications, monitored control room indications for abnormalities, verified that electrical power was available, and observed the frequency of plant and control room visits by station managers. The inspectors also monitored various administrative and operating records.

The inspectors observed good operator attention to panel indications during control room tours. Specifically:

- The Unit 2 operator observed a 1% increase in thermal power during steady state operations. The licensee determined a heater drain valve had stuck closed.
- The center desk operator noticed that the Unit 3 EHC pressure controller indicated channel A and B were simultaneously in control. The center desk operator promptly notified the unit operator. A work request was generated.

The licensee implemented computerized rounds for the equipment operators. The equipment operators were very receptive to the new program which provided better historical information on equipment performance.

Accessible portions of ESF systems and associated support components were inspected to verify operability through observation of instrumentation and proper valve and electrical power alignment. The inspectors also visually inspected components for material condition. Specifically, the following systems were inspected by direct field observations:

Service water radiation monitors
Containment cooling service water
Low pressure coolant injection

Plant Operations Observations

a. Drywell and Torus Venting Practices Outside Design

On December 22, 1993, the licensee determined that the practice of venting the drywell and torus through the reactor building was contrary to the description in the Updated Final Safety Analysis Report (UFSAR). Site engineering personnel identified the discrepancy during the final review of the rebaselined UFSAR. The licensee immediately restricted venting to the standby gas treatment system (SBGT).

The normal venting procedure 1600-01, "Normal Venting of the Drywell or Torus," allowed venting through the reactor building while at power when samples were within a specified tolerance. However, UFSAR section 6.8.3.2. stated that venting and purging during normal operation was accomplished through the SBGT system. Venting through the reactor building was allowed during startups and shutdowns after appropriate sampling. Technical Specification 3.8.B. stated that venting will be performed in accordance with the offsite dose calculation manual. The standard radiological effluent technical specifications (RETS) for a BWR Mark I containment required venting through the SBGT system.

After further investigation, the licensee determined that the UFSAR description was in error and that previous exemptions from the RETS were previously approved by the NRC. This issue is considered an Unresolved Item (50-237/93034-01(DRP)) pending review of this documentation.

b. Emergency Operating Procedures

The licensee's Site Quality Verification group performed an audit of the emergency operating procedures (EOPs) at the request of the station manager in August 1993. The results of that audit showed some weaknesses in the EOP program. However, none of the items were safety significant. The inspectors determined no progress had been made on resolving these identified weaknesses because of insufficient management attention. The EOP coordinator had initiated a multi-disciplined team approach to maintaining the EOPs and the attendant documentation. This approach appeared to provide the necessary expertise and resources. The effectiveness of this approach will be assessed during future inspections.

c. Personnel Error Reduction

Following a series of operator errors, a reactor operator agreed to discuss methods of reducing errors with each shift of operators. The reactor operator performed a limited scope study in order to understand the work activities in progress when errors were made. The operator determined the number of activities, such as out-of-service requests and surveillances, from the operator logs. An interesting result of this study was that errors occurred during shifts with less activity.

The reactor operator presented this information to each shift of non-licensed operators and stressed self-check, particularly during periods of low to moderate activity, and procedure use. The inspectors viewed this effort to involve operators in problem resolution as positive.

d. Plant Scaffolding

During a review of site requirements for erecting scaffolding, the inspectors determined that the licensee was not adequately addressing seismic requirements for scaffolding in safety-related applications, i.e. adjacent or over operating or operable safety-related equipment. The licensee indicated a corporate project was initiated to provide improved engineering analysis of scaffolding designs. The licensee generated a problem identification form (PIF) to address the adequacy of performing safety evaluations on scaffolding erected in the plant. The licensee indicated that a separate PIF was to be issued to incorporate additional concerns in the overall scaffolding process. The additional areas to be covered included: 1) lack of training of personnel in seismic requirements; and 2) a review and signoff for a structural inspection for seismic requirements. The inspectors had no further concerns.

e. Operational Events

During the inspection period, additional events occurred, some of which required a prompt notification of the NRC pursuant to 10 CFR 50.72. The following events were reviewed for reporting timeliness and immediate licensee response:

- On December 1, 1993, the recirculation loop sample outboard containment isolation valve closed due to a blown fuse.

- On December 15, 1993, the Unit 3 high pressure coolant injection (HPCI) supply valve auto closed. Electrical maintenance personnel working on the HPCI logic wiring bumped the relay and caused the valve to close.

- On January 1, 1994, six feet of a sixty foot wooden 138kV power pole broke and resulted in an electrical perturbation in the Unit 2 control room annunciator power supplies. All annunciators were lost for about 3 minutes until a blown fuse was replaced. The 902-5 panel annunciators remained inoperable for about 10 hours while individual drive controller cards were replaced. The licensee was investigating the correlation between the 138kV line and the annunciator power supply.

The root cause and licensee corrective actions will be evaluated during the review of the respective licensee event reports or problem investigation reports.

No violations or deviations were identified. One unresolved item was identified regarding venting the drywell or torus through the reactor building.

4. Monthly Maintenance and Surveillance (62703 and 61726)

Station maintenance and surveillance activities were observed and/or reviewed to verify compliance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with technical specifications (TS).

The following items were considered during this review: approvals were obtained prior to initiating the maintenance work or surveillance testing and operability requirements were met during such activities; functional testing and calibrations were performed prior to declaring the component operable; discrepancies identified during the activities were resolved prior to returning the component to service; quality control records were maintained; and activities were accomplished by qualified personnel.

The inspectors observed portions of the following maintenance activities:

Unit 2:

2B condensate booster pump repair and alignment
Station blackout (SBO) diesels and aux equipment installation
Troubleshooting 2B MSIV double indication
Motor and shaft replacement of the 2A circulating pump
Installation of the 2B instrument air compressor

Unit 3:

SBO diesels and aux equipment installation
250V battery installation
Service air compressor repair
Condensate transfer pump repair
Diesel oil spill removal of contaminated material
Lap and test electromatic relief pilot valve
Trouble shooting of MO3-1402-38B

The inspectors also witnessed portions of the following test activities:

Unit 2:

DIS 0201-01 Monthly Reactor Vessel 600 psig Scram Bypass
DIS 500-01 Vessel High Pressure Scram
DIS 500-02 Reactor Vessel Low Water Level Scram and Low Low Water Level Isolation Analog trip System Calibration
DIS 500-07 Turbine First Stage Pressure, 45%, Calibration
DIS 1300-05 Isolation Condenser Level Transmitter Calibration
DIS 1500-01 Monthly Reactor Low Pressure
DIS 1500-09 Semi-annual Recirculation Pump Delta Pressure Switch Calibration
DOP 1600-01 Normal Venting of the Drywell or Torus
DIS 4100-01 Emergency Fire Pump Discharge Pressure Gauge Functional Test and Flow Indication Calibration

Unit 3:

DIS 0201-01 Monthly Reactor Vessel 600 psig Scram Bypass
DIS 500-01 Vessel High Pressure Scram
DIS 500-02 Reactor Vessel Low Water Level Scram and Low Low Water Level Isolation Analog trip System Calibration
DIS 500-07 Turbine First Stage Pressure, 45%, Calibration
DIS 1300-05 Isolation Condenser Level Transmitter Calibration
DIS 1400-05 Core Spray Pump Test for Inservice Testing
DOP 1600-01 Normal Venting of the Drywell or Torus

Maintenance and Surveillance Observations

a. Repetitive Reactor Water Level Switches Out Of Tolerance

The emergency core cooling systems (ECCS) were designed to actuate at certain reactor water levels to mitigate the consequences of an accident. Four level switches in a one-of-two twice logic cause the initiation when the specified levels are sensed. Each switch consisted of six or eight contacts which correspond to different ECCS initiation logic. One set of contacts on two levels switches provided the high level isolation for the high pressure coolant injection (HPCI) system.

As discussed in Inspection Report 50-237/92036, the ECCS level switches had a history of failures. During 1991 and 1992, the licensee experienced at least 20 level switch failures. The licensee placed the instruments on the Top 50 technical issues list to expedite resolution. A technical specification change request was submitted in March 1993 to replace the four inch tolerance band with a lower limit. The licensee also replaced the Unit 2 switches with an enhanced Yarway model during the March 1993 refueling outage.

The 1993 failures are listed in Attachments 1 and 2. The level switches failed 17 and 12 times for Units 2 and 3, respectively. The inspectors were particularly concerned with the Unit 2 failure rate because the failures occurred after replacements. On four occasions, the switches failed to trip three times and tripped late once. The proposed TS change would not have eliminated these failures. In addition to the TS change, the licensee was pursuing possible equipment changes. The licensee's progress to resolve these recurring instrument failures is considered an Unresolved Item (50-237/93034-02(DRP)).

The licensee submitted licensee event reports (LER) in January and October 1993 when multiple contacts were found outside TS tolerances. However, the licensee did not submit LERs for the single remaining failures. 10 CFR 50.73 required written notification for any condition that could have prevented the fulfillment of a safety function. NUREG-1022, "Licensee Event Report System," stated "...judgment must be made whether a failure that did actually disable one train of a safety system, could have, but did not affect a redundant train within an ESF system. If so, this would constitute an event that 'could have prevented' the fulfillment of a safety function, and, accordingly, must be reported." Further clarification was presented in example C-8 which stated an event was reportable if it was indicative of a generic and/or repetitive problem in several safety systems. The numerous random failures of these switches were indicative of a recurring generic equipment problem. It was fortuitous that one contact set failed at a time. Failure to submit LERs is considered an Unresolved Item (50-237/93034-03(DRP)) pending the inspector review of the licensee's present evaluation.

b. Main Steam Isolation Valve Testing

The inspectors reviewed the process for leak rate testing main steam isolation valves (MSIVs). The licensee on occasions flushed the valve seat with water prior to testing the valves. The inspectors questioned whether this activity would constitute preconditioning of the valves. This is considered an Unresolved Item (50-237/93034-04(DRP)) pending review of the test procedure, the limitations when flushing may occur, and the method of draining the system prior to leak rate testing.

c. Maintenance Backlog

The backlog of non-outage corrective maintenance work requests (now-corrective) continued to increase and reached approximately 1850 by the end of the inspection period. The licensee's goal for now-corrective work requests was 1300, but there was no plan in place to achieve this goal. The licensee determined work package preparation and the work control process were significant contributors to the backlog increase. Accordingly, the licensee revised the work control structure in an attempt to provide more work packages to the maintenance departments. However, these actions were not sufficient to effect a reduction in the backlog.

The licensee had completed a corporate work control study which resulted in a number of recommendations. The licensee was beginning implementation of some of these recommendations. The inspectors will monitor the progress of these activities during upcoming inspections.

The licensee had an additional goal to complete now-corrective control room work requests within 2 weeks of initiation. This ambitious goal was not met. A primary contributor to the control room backlog was repetitive instrumentation failures. The licensee initiated a program to reduce the repetitive instrument failures.

The adequacy of licensee actions to reduce the work request backlog will be reviewed in future inspections.

d. D3R13 Outage Preparations

The inspectors reviewed the licensee's preparations for the forthcoming refuel outage for Unit 3. The following strengths in outage management were observed:

- System schedules showed good logic and logic-ties with other system schedules. The teamwork between system engineers, site engineering, and the maintenance shops in the development of these schedules was good.

- The involvement of radiation protection personnel in the work request by work request review to establish the outage exposure goal of 650 person-rem was good.

The inspectors will continue to monitor the licensee's preparation activities.

One violation was identified for the failure to submit licensee event reports. One unresolved item regarding the reliability of reactor water level switches was identified. One unresolved item for the MSIV testing methodology was identified.

5. Engineering and Technical Support (37700)

The inspectors evaluated the extent to which engineering principles and evaluations were integrated into daily plant activities. This was accomplished by assessing the technical staff involvement in non-routine events, outage-related activities, and assigned TS surveillances; observing on-going maintenance work and troubleshooting; and reviewing deviation investigations and root cause determinations.

Engineering and Technical Support Events

a. Violation of Order LS05-83-03-028

In the December 15, 1980, response to the implementation requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," the licensee stated that the requirements for Item II.K.3.24, "Space Cooling for HPCI/RCIC," were met because the high pressure core injection (HPCI) system room coolers were supplied from pumps powered by the emergency diesel generators. On March 14, 1983, the Office of Nuclear Reactor Regulation issued an Order, Docket Nos. 50-237/249, LS05-83-03-028, confirming the licensee's commitments to post-TMI related issues, including the licensee's position on Item II.K.3.24. The Order required the licensee to implement and maintain the specific items described in the Attachments to the Order in the manner described. (Item II.K.3.24 was contained in Attachment 1 to the Order.)

In 1990, the licensee installed flow instrumentation in the Units 2, 3, and 2/3 diesel generator cooling water (DGCW) systems and noted marginal pump flows. To increase cooling flow to the diesel generators, the licensee valved out the DGCW cooling supplies to the emergency core cooling system (ECCS) room coolers. The licensee did not recognize this action did not comply with the 1983 Order. Failure to request an amendment to the Order prior to isolating the ECCS room coolers is considered a Violation of the Order Confirming Licensee Commitments on Post-TMI Related Issues, Serial No. LS05-83-03-028 (50-237/93034-05(DRP)).

The safety significance of isolating the room coolers was minimal. The licensee performed an engineering evaluation which showed the equipment located within ECCS corners rooms would remain operable for a period in excess of one hundred hours without room cooling. This exceeds the cooling requirements established by Item II.K.3.24. However, the inspectors were concerned by the licensee's inability to assess the impact of proposed plant changes on commitments made to the NRC. The licensee should address this concern in the response to the violation.

b. Appendix J Untested Lines

On January 5, 1994, the licensee identified a portion of the Unit 2 core spray (CS) leak detection system had not been tested per 10 CFR 50 Appendix J requirements. The piping was located off a tee between the instrument line isolation valve and the excess flow check valve. Although the licensee did not perform Appendix J tests on instrument lines with excess flow check valves, this piping represented another penetration point and required testing. The untested piping was used for corrosion test monitoring during the first year of operation and was later abandoned in place. Also, the piping was not identified on the piping and instrument diagram. The licensee performed an engineering evaluation and determined that although the untested piping did not meet design requirements, the CS leak detection system was operable.

Later on January 5, the licensee identified a portion of piping on the Unit 3 below core plate pressure instrument line also had not been tested. The piping was also located between the isolation valve and the excess flow check valve. Three valves located immediately downstream of the tee were safety related, seismically mounted, and exposed to greater than Appendix J testing pressure under normal operating conditions. The licensee verified the integrity of each valve and declared the instrument line operable.

The untested lines are considered an Unresolved Item (50-237/93034-06(DRP)) pending review of the licensee's investigation and corrective actions.

c. Inaccurate Control Room Critical Drawings

While investigating the 3B CS minimum flow valve failure to open, the instrument mechanics noted that the control room critical drawing incorrectly indicated four rotor logic. After further investigation, the licensee identified 43 similarly inaccurate critical valve schematic diagrams. During the Spring 1992 Unit 3 refueling outage, the licensee completed two-to-four rotor modifications on the loop A emergency core cooling system valves. However, the loop B valve schematics were changed to reflect the modification instead of the A loop valves as intended. The licensee was unable to ascertain whether the drawing discrepancies occurred at the end of the outage or in April 1993 when the critical drawings were again revised.

Previously Inspection Report 50-237/93012 documented a programmatic problem with the administrative control of critical drawings. The recently identified discrepancies are considered an Unresolved Item (50-237/93034-07(DRP)) pending review of the licensee's investigation and corrective actions.

d. Diesel Generator Operability

The inspectors reviewed the licensee's evaluation of the operability of the 2/3 diesel generator following a loss of power to the lubricating oil pumps. The licensee determined the diesel generators were operable for a period of 48 hours following loss of the lubricating oil pumps. The licensee has initiated action to improve the availability of the lubricating oil system. The inspectors had no concerns with the operability evaluation.

One violation of an Order was identified. One unresolved item for untested piping was identified. One unresolved item regarding critical drawings was identified.

6. Plant Support (71707 and 93702)

The inspectors evaluated the involvement of support organizations in assuring safe and effective plant operation. Specific areas included:

- Radiation Protection Controls

  The inspectors verified workers were following health physics procedures and randomly examined radiation protection instrumentation for operability and calibration.

- Security

  During the inspection period, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan. No discrepancies were identified.

- Emergency Preparedness

  The inspectors verified the operational readiness of the control room technical support center and operation support center. Non-routine events were reviewed to insure proper classification and appropriate emergency management involvement.

- Housekeeping and Plant Cleanliness

  The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign material.

Plant Support Related Observations

a. Potential Unmonitored Release Through Floor Drain System

On December 16, 1993, the licensee determined that several floor drains inside the radiological controlled area were routed directly into non-contaminated process systems. This configuration resulted in the potential for two unmonitored release paths: from the Unit 2/3 transformer oil separator to the canal and from the waste water treatment building to the canal. The licensee immediately placed administrative controls on the transfer pumps, changed sampling frequency from weekly to daily, and placed labels on the affected drains. The inspectors verified these immediate corrective actions were implemented. The root cause and long term corrective actions was being evaluated by regional specialist inspectors.

b. Electronic Dosimetry

On December 14, 1993, a notification was issued from LaSalle Station regarding an administrative overexposure which was potentially caused by a failure of the audible alarm in an electronic dosimeter. In the December 17 Dresden daily update, the licensee included a description of the event, a warning not to depend on the audible alarm, how to check the proper functioning of the alarm, and a review of the audible alarms. This update provided timely and complete information to station workers to help avoid a similar overexposure and was considered a strength.

No violations or deviations were identified.

7. Safety Assessment and Quality Verification (SAQV) (40500)

The effectiveness of management controls, verification and oversight activities in the conduct of jobs observed during this inspection were evaluated. Management and supervisory meetings involving plant status were attended to observe the coordination between departments. The results of licensee corrective action programs were routinely monitored by attendance at meetings, discussion with plant staff, review of deviation reports, and root cause evaluation reports.

SAQV Related Events

a. Unsecured Portable Equipment

On January 5, 1994, the inspectors observed three portable carts in the instrument panel area of the control room. One cart supported an instrument which was connected to terminal strips in the instrument racks, one cart supported a computer terminal, and the remaining cart was empty. Also on January 10, the inspectors observed an unsecured cart near a safety-related motor control center. None of the carts were secured or attended as required by Dresden Administrative Procedure (DAP) 3-20, "Restraint of Portable Equipment." On September 27, 1993, a Notice of Violation (50-237/93020-7b(DRP)) was issued for several examples of failing to follow DAP 3-20. The licensee emphasized to station personnel management's expectations for procedure compliance, and responded to the Notice on October 27, 1993, stating Dresden Station was in full compliance. The licensee's failure to prevent recurrence indicated the previous corrective actions were inadequate and is considered a Violation of 10 CFR 50 Appendix B Criterion XVI (50-237/93034-08(DRP)).

b. Corrective Action Program

The inspectors reviewed the licensee's Problem Identification Forms (PIFs) to monitor the conditions related to plant or personnel performance and potential trend. The following observations were made:

- On October 4, 1993, a PIF identified an unofficial, marked-up procedure was used to perform off-gas system samples. The resolution of this PIF was to submit a temporary procedure change and to document the causal factor as technical inaccuracies in written communications.

- On November 27, 1993, a PIF identified certain deficiencies during the Unit 2 drywell closeout inspection. Two of these deficiencies involved disconnected ductwork supports. The resolution of this PIF was to add a walkdown at the beginning of an outage to identify deficiencies earlier.

The inspectors reviewed the above PIFs and determined the licensee failed to identify the true problem. In the first case the true problem was technicians were not following procedures. This problem allowed an incorrect procedure to remain in place. In the second case, one of the true problems was personnel disconnected and did not restore duct supports. The originators of the above PIFs described a set of circumstances; however, neither the event screening committee or the evaluator documented the true problems to be evaluated. This weakness in the program will be evaluated in further inspections.

One violation for inadequate corrective actions was identified.

8. Licensee Actions on Previous Inspection Findings 92701, and 92702)

(Closed) Violation (50-237/93009-03(DRP)): Inadequate testing following the containment cooling service water and control room ventilation cross connect modification. The licensee's modification program was revised since the subject modification was installed in 1985. The revised procedure required the engineer to consider system interfacing and identify necessary testing to ensure system operability. This item is closed.

(Closed) Unresolved Item (50-237/91027-03 (DRP)): Non-safety related sealant material used with safety related applications. The inspectors reviewed the licensee's evaluation of the safety function of these sealant materials and found the classification as non-safety related to be appropriate. This item is closed.

(Closed) Inspector Followup Item (237/92026-01): Replacement of CR120A relays. The licensee has replaced approximately 50% of the relays on Unit 2 and intends to replace the remaining relays during the 1994 and 1995 refueling outages for both units. This item is closed.

(Closed) Inspector Followup Item (50-237/92032-02(DRP)): Corrective actions from LER 237/91029. The licensee determined that eliminating the main steam line radiation monitors from the technical specification was non-conservative and was therefore not performed. The licensee revised the calibration procedure to include a supervisor's review of the data after each instrument calibration. This item is closed.

No deviations or violations were identified.

9. <u>Licensee Event Reports (LERs) Followup (92700)</u>

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.

<u>Unit 2</u>

<u>(Closed) LER 237/91009, Revision 2</u>: Failure of Standby Gas Treatment System Charcoal Adsorber Leak Test Due to Seal Leakage. This revision clarified the completed corrective actions. The inspectors identified numerous weaknesses associated with the testing as documented in paragraph 3.f. of Inspection Report 50-237/92020. This LER is closed.

<u>(Closed) LER 237/92013 Revisions 0 and 1</u>: High Pressure Coolant Injection Supports Outside FSAR Allowables Due to Water Hammer. The licensee identified the circumstances causing the water hammer events and modified operating procedures to avoid recurrence. This LER is closed.

<u>(Closed) LER 237/92030 Revision 0</u>: Pipe Supports for the Containment Atmosphere Sampling System Not Connected to Structural Steel. This deficiency was possibly an original design or construction deficiency and was corrected by the licensee. This LER is closed.

<u>(Closed) LER 237/92033, Revision 0</u>: Inadvertent Unit 2/3 Diesel Generator Auto Start. The undervoltage relay jarred and sealed in when the cubicle door closed and resulted in the automatic start. This LER is closed.

<u>(Closed) LER 237/92036, Revision 0</u>: Technical Specification 3.9.B.2 Violation; Failure to Run Unit 2 and 3 Diesel Generators (DG) With 2/3 DG Inoperable Due to Personnel Error. This event occurred on October 26, 1992. On October 29, 1992, the technical specification violated by this event was deleted. In accordance with 10 CFR 2, Appendix C, this violation is not being cited since the event was identified by the licensee, had minimal safety significance, and prompt corrective actions were taken. This LER is closed.

<u>(Closed) LER 237/93002 Revisions 0 and 1</u>: Local Leak Rate Testing of Containment Isolation Valves Exceeded Technical Specification Limits. This LER is closed.

<u>(Closed) LER 237/93017, Revision 0 and 1</u>: Unusual Event Not Declared in July From Both Unit 2 and Unit 2/3 Diesel Generators Being Inoperable Due to Personnel Error. This event was discussed in paragraph 4.a. of Inspection Report 50-237/93024. Although the licensee concluded the 2/3 diesel generator was technically operable (discussed in paragraph 5 of this report), operations personnel should have declared the 2/3 DG

inoperable based on the available procedural guidance. The failure to recognize both DGs were inoperable resulted in a violation of TS 3.0.A. In accordance with 10 CFR 2, Appendix C, this violation is not being cited since the event was identified by the licensee, had minimal safety significance, and prompt corrective actions were taken. This LER is closed.

(Closed) LER 237/93019 Revision 0: High Pressure Coolant Injection Declared Inoperable Due to Failed High Reactor Water Level Turbine Trip Switch. This event is discussed in paragraph 4.a. This LER is closed.

(Closed) LER 237/93020 Revision 1: Undetected Thermal Limit Violation Due to Personnel Error. This event is the subject of Unresolved Item (50-237/93024-02(DRP)). This LER is closed.

Unit 3

(Closed) LER 249/92004 Revision 0: Improper Setpoint of Second Level Undervoltage Relays. This LER documents a similar condition to that described in LER 237/91021, and is closed to that LER.

(Closed) LER 249/92021, Revisions 0 and 1: Reactor Scram Due to 3B Condensate/Condensate Booster Pump Motor Failure and Subsequent Events. This LER is closed.

(Closed) LER 249/93002, Revision 0: Control Valve Fast Closure Half-Scram Pressure Switches Out-of-Calibration Due to Setpoint Drift. As a preventive measure, the licensee will calibrate these switches during each cold shutdown greater than 72 hours in duration after any cumulative 90 days of operation. Additionally, the licensee will track the performance of the new single microswitch pressure switches under the Equipment Reliability Issues Database. This LER is closed.

(Closed) LER 249/93018 Revision 1: High Pressure Coolant Injection Outside FSAR Design Requirements Due to Disabled Turbine Trip. On previous occasions, the licensee jumpered the remaining contacts on the level switch in order to maintain operability. During this event, the instrument mechanic placed the level switch in downscale and rendered the automatic isolation of HPCI inoperable. The licensee intends to revise the calibration procedure. This LER is closed.

Two licensee identified violations for failure to follow technical specifications were discussed.

10. Management Meetings (30703)

On December 10, 1993, Mr. H. Miller, Deputy Regional Administrator, met with Mr. M. Lyster, Site Vice President and other licensee personnel to gain insights into recent personnel errors.

No violations or deviations were identified.

11. Unresolved Items

Unresolved items are matters which more information is required in order to ascertain whether they are acceptable items, items of noncompliance or deviations. Six Unresolved Items disclosed during this inspection are discussed in paragraphs 3.a, 4.a, 4.b, 5.b. and 5.c.

12. Licensee Identified Violations

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section VII.B.(2). These tests are:

(1) it was identified by the licensee

(2) it was not a violation that could have reasonably been prevented by corrective action to a previous violation.

(3) the violation was or will be corrected, including measures to prevent recurrence, within a reasonable time; and

(4) it was not a willful violation.

Two violations of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued are discussed in paragraph 9.

13. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) throughout the inspection period and at the conclusion of the inspection on January 10, 1994, to summarize the scope and findings of the inspection activities. The licensee acknowledged the inspectors' comments. 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 or processes as proprietary.

Attachment 1: Emergency Core Cooling System Reactor Level Switches

Unit 2

Date	Level Switch	Logic	As Found dP	As Found MR Level (inches)	Required Level (inches)
06/11/93	263-72A contact 7-8	CS, ADS and DG start logic	180.16	-88.6	-59
06/11/93	263-72C contact 5-6	LPCI and HPCI start logic	160.65	-60.8	-59
07/12/93	263-72A contact 7-8	CS, ADS and DG start logic	didn't trip	*	-59
07/15/93	263-72B contact 5-6	LPCI start logic	didn't trip	*	-59
07/19/93	263-72C contact 5-6	LPCI and HPCI start logic	160.3	-60.4	-59
08/09/93	263-72A contact 7-8	CS, ADS and DG start logic	didn't trip	*	-59
09/03/93	263-72C contact 5-6	LPCI and HPCI start logic	166.1	-68.6	-59
10/01/93	263-72C contact 7-8	CS, ADS and DG start logic	161.8	-62.5	-59
10/01/93	263-72C contact 5-6	LPCI and HPCI start logic	161.8	-62.5	-59
10/29/93	263-72C contact 7-8	CS, ADS and DG start logic	154.8	-52.5	-59
10/29/93	263-72C contact 5-6	LPCI and HPCI start logic	154.6	-52.3	-59
11/23/93	263-72C contact 5-6	LPCI and HPCI start logic	163.9	-65.5	-59
11/23/93	263-72C contact 7-8	CS, ADS and DG start logic	162.1	-62.9	-59
12/22/93	263-72C contact 5-6	LPCI and HPCI start logic	155.0	-52.8	-59

Unit 3

Date	Level Switch	Logic	As Found dP	As Found MR Level (inches)	Required Level (inches)
01/13/93	263-72B contact 5-6	LPCI start logic	114.8	-59.7	-59
01/13/93	263-72A contact 5-6	LPCI and HPCI start logic	114.9	-59.9	-59
01/13/93	263-72A contact 7-8	CS, ADS and DG start logic	114.9	-59.9	-59
02/25/93	263-72B contact 5-6	LPCI start logic	114.96	-59.9	-59
06/16/93	263-72B contact 7-8	CS, ADS, HPCI, DG start logic	115.9	-61.3	-59
07/14/93	263-72B contact 7-8	CS, ADS, HPCI, DG start logic	118.8	-65.4	-59
08/16/93	263-72B contact 7-8	CS, ADS, HPCI, DG start logic	119.92	-66.9	-59

The technical specification limit is +84 inches above the top of active fuel which corresponds to -59 inches on the Medium Range scale.

Attachment 2: High Pressure Coolant Injection High Reactor Level Isolation

Unit 2

Date	Level Switch	Logic	As Found dP	As Found MR Level (inches)	Required Level (inches)
08/10/93	263-72B contact 3-4	HPCI turbine trip/high level	87.6	42.9	48
09/03/93	263-72B contact 3-4	HPCI turbine trip/high level	98.4	27.6	48
10/01/93	263-72B contact 3-4	HPCI turbine trip/high level	didn't trip	*	48

Unit 3

Date	Level Switch	Logic	As Found dP	As Found MR Level (inches)	Required Level (inches)
01/28/93	263-72A contact 3-4	HPCI turbine trip/high level	41.2	44.2	48
01/28/93	263-72B contact 3-4	HPCI turbine trip/high level	43.2	41.4	48
02/25/93	263-72B contact 3-4	HPCI turbine trip/high level	36.75	50.5	48
04/21/93	263-72B contact 3-4	HPCI turbine trip/high level	41.2	44.2	48
06/16/93	263-72B contact 3-4	HPCI turbine trip/high level	38.84	47.5	48

* The HPCI isolation logic required both contacts to make up. The data showed that in October 1993, operator actions would have been required to isolate the Unit 2 HPCI turbine.