U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/94002(DRP); 50-249/94002(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: January 11 through February 22, 1994

Inspectors: M. Leach
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Approved By: P L Hiland 3/8/94
P. L. Hiland, Chief Date
Reactor Projects Section 1B

Inspection Summary

Inspection from January 11 through February 22, 1994 (Report Nos. 50-237/94002(DRP); 50-249/94002(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; reactor water level instrumentation; licensee action on previous inspection findings; and licensee event report review.

Results: Of the eight areas inspected, no violations or deviations were identified in five areas. One apparent violation for inadequate or untimely corrective actions was identified in paragraph 8. One violation for the failure to submit a Licensee Event Report when reactor water level switches were found out of technical specification limits is discussed in paragraph 5.a. One deviation from a commitment in response to Generic Letter 89-13 is discussed in paragraph 3.a.

Assessment of Plant Operations

An equipment operator was attentive to equipment status and identified a faulty diesel generator air regulator valve. Operations management showed leadership and direction during a potential Unit 3 shutdown due to two inoperable diesel generators. Actions for a controlled, planned shutdown were discussed with the operating crew in the event the shutdown was necessary. However, management expectations regarding procedure adherence were not clearly delineated and resulted in an NRC identified deviation from a commitment. In addition, the lack of management oversight resulted in ingress of service water to the Unit 1 containment.

Assessment of Maintenance and Surveillance

Numerous improvement efforts in the instrument maintenance area were initiated and demonstrated good management attention and worker response. Coordination and execution of maintenance activities on the Unit 2/3 and Unit 3 diesel generators were good. However, instrument mechanics did not retain failed mercury switches for root cause evaluations.

Assessment of Engineering and Technical Support

Site engineering support to operations and maintenance on the Unit 2/3 diesel generator air regulator failure was good. The evaluation which considered the impact of increased air pressure on equipment downstream of the faulty valve was thorough. System engineering involvement and support to maintenance on the Unit 3 diesel generator was good.

Site and system engineering did not recognize the significance of the reactor water level instrument adverse performance trend. No root cause determinations were completed for failed switches. The numerous failures within the past year indicated licensee action to resolve this issue was not commensurate with the safety significance of the problem. Also, the licensee did not submit written notification for failed reactor water level switches and resulted in an NRC identified violation. Numerous weaknesses were identified in one licensee event report. After the reactor water level instrumentation issue was brought to engineering's attention, the performance of site engineering was aggressive and appropriate.

Assessment of Plant Support

The newly formed composite cleaning crews was a good initiative to systematically clean and decontaminate areas in the plant. The untimely distribution of Information Notices was a weakness.

Assessment of Safety Assessment and Quality Verification

Management did not ensure appropriate actions were taken to resolve the recurring reactor water level instrument failures and drifts.

DETAILS

1. Persons Contacted

*M. Lyster, Site Vice President
*G. Spedl, Manager, Dresden Station
*R. Aker, Technical Services Superintendent
*M. Korchynsky, Senior Operating Engineer
*J. Kotowski, Operations Manager
*H. Massin, Engineering Manager
*T. O'Connor, Maintenance Superintendent
*B. Palagi, Unit 1 Project Manager
*R. Radtke, Services Superintendent
R. Robey, Director, Safety Quality Verification
*J. Shields, Regulatory Assurance Supervisor
*M. Strait, Technical Staff Supervisor
J. Williams, Operations Support Supervisor

* Indicates persons present at the exit interview on February 23, 1994.

The inspectors also contacted other licensee personnel including members of the operating, maintenance, engineering, and plant support departments.

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.

Unit 3

The unit continued coasting down throughout the period.

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 equipment operator (EO) attention to plant equipment and good operations management. Specifically;

- An EO identified a faulty air regulator valve on the Unit 2/3 diesel generator (DG) on February 3 and the DG was declared inoperable. Verification of proper air pressure was not required on that shift.

- Operations management showed good leadership and direction during a potential Unit 3 shutdown due to two inoperable diesel generators. Actions for a controlled, planned shutdown were discussed with the operating crew in the event the shutdown was necessary.

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:

Unit 3 and Unit 2/3 DGs
Units 2 and 3 reactor water level instrumentation

Plant Operations Observations

a. Deviation From Commitment Due to Procedural Adherence Error

During the performance of Special Procedure 93-11-110, "Differential Pressure Test of MO 3-1501-13B," revision 0, the licensee failed to perform a step resulting in a deviation from a commitment. Step I.4.a required chemical injection to be initiated. This step was annotated by the reactor operator "NA (not applicable) system frozen." The next step instructed the operator "WHEN Sodium Hypochlorite injection into the Circulating Water System is initiated, THEN IMMEDIATELY perform the following: (1) Start 3A containment cooling service water (CCSW) pump, (2) Start 3D CCSW pump." The operator performed these steps although chemical injection was not in service. The inspectors noted that the chemical injection system had been frozen since December 30, 1993. The system was repaired on February 17, 1994. No injections to Units 2 & 3 CCSW intake bays occurred during this time period.

The inspectors queried operations management on procedure adherence expectations in this situation. The inspectors reviewed Dresden Administrative Procedure (DAP) 9-11, "Conduct of Surveillance, Special and Complex Procedures," which stated that if a step cannot be performed then document the problem and the basis for continuing. This was not performed in this case. The inspectors reviewed DAP 9-13, "Procedural Adherence," which stated (1) if a step cannot be performed the supervisor shall determine if work can be continued; or (2) if work cannot continue within the constraints of the procedure, a procedure change shall be initiated. The above administrative procedures provided confusing guidance on procedural adherence. The administrative procedures were generally cumbersome and difficult to use. For example DAP 09-01, "Station Procedures," referred to DAP 09-11, "Procedure Usage and Adherence," which was actually DAP 09-13, "Procedural Adherence." DAP 09-01 also referred to DAP 09-13, "Procedural Response to Abnormal Conditions," which did not exist. DAP 07-02, "Conduct of Operations," also provided some guidance on procedure usage. Not one of these documents provided a clear and concise expectation with regards to procedure adherence.

Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment," required licensees to take actions to ensure service water systems remained reliable. One requirement was to implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling. In a letter to the NRC on January 29, 1990, the licensee committed that for open cooling water systems, a biocide would be injected manually into the intake bay during operation. Between December 30, 1993, and February 17, 1994, the CCSW systems for Units 2 and 3 were operated on several occasions without biocide addition to the intake bays. This is a Deviation from commitments made in response to Generic Letter 89-13 (50-237/94002-01(DRP)). The root cause for this deviation was delayed maintenance actions coupled with inadequate procedural adherence. The licensee completed an investigation into procedure adherence problems and initiated a revision of the administrative procedures. The licensee provided a "Basic Expectations" document to employees which stressed procedure adherence. The inspectors will continue to monitor the licensee's efforts to improve procedure adherence.

b. Operational Events

During the inspection period, events occurred which were reviewed by the inspectors for the immediate licensee actions. The licensee's root cause investigation and corrective actions will be reviewed during future inspection activities.

- On January 25, 1994, the licensee discovered about four feet of contaminated water in the Unit 1 containment basement. The licensee found several service water pipes cracked due to freezing conditions. No heat was provided to the Unit 1 containment. A special NRC team of eight regional and headquarters inspectors investigated the root cause and corrective actions. The special team findings were documented in Inspection Report 50-010/94001.

- On February 2, 1994, the licensee identified containment isolation valve 3-2599-5A had exceeded its maximum stroke time on January 24. The licensee's final assessment of that anomaly was ongoing at the end of the inspection period.

No violations were identified. One deviation from a commitment in response to Generic Letter 89-13 was identified.

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 3

Investigation and repair of Unit 3 DG cooling water leak
Repair of Unit 2/3 DG air regulator valve

The inspectors also witnessed portions of the following test activities:

Unit 2

DIS 287-03 Auto Blowdown Permissive Low Pressure Coolant Injection and Core Spray Pump Discharge Pressure Switches
DIS 0500-03 Reactor Water Level Emergency Core Cooling System (ECCS) Initiation Indicating Switch Calibration

Unit 3

DIS 0500-03 Reactor Water Level ECCS Initiation Indicating Switch Calibration
DOS 6600-01 Diesel Generator Surveillance Test
DOS 1600-05 Unit 3 Quarterly Valve Testing

Maintenance and Surveillance Observations

a. Improvement Activities in Instrument Maintenance

The inspectors observed some significant improvement in the performance of the instrument maintenance department during this inspection period. This improvement began with a clear statement of expectations from senior management, and was followed by improved leadership by middle management. This resulted in the following activities:

- A reduction of 100 work requests in 5 weeks in the instrument department work request backlog.
- Development of a minor instrument maintenance procedure to allow minor work activities without a work package.
- Establishment of a status board which showed the current state of the instrument maintenance department backlog.
- Improved involvement of technicians in solving long standing problems with equipment and work practices. One improvement involving the traversing incore probe reduced the likelihood of contamination and personnel overexposures.

Of particular note was the enthusiasm of some of the workers to drive the backlog to zero. The inspectors will continue to monitor these developments and will look for similar improvements in the other maintenance areas.

b. Maintenance work on Unit 2/3 and Unit 3 Diesel Generator

On February 2, the licensee observed increased crankcase pressure due to water intrusion during Unit 3 DG testing. The licensee declared the DG inoperable and entered a seven day limiting condition for operation (LCO). The licensee determined the cooling water heat exchanger was the source of the water leak and commenced repairs. On February 3, an equipment operator identified a faulty air regulator on the Unit 2/3 DG. The licensee declared the Unit 2/3 DG inoperable and initiated a 24 hour LCO. Maintenance personnel replaced the air regulator and site engineering evaluated the effect of increased pressure on other valves downstream of the failed regulator. The licensee did not identify any problems and declared Unit 2/3 DG operable within the LCO time limit. On February 6, the licensee declared the Unit 3 DG operable after replacement of the heat exchanger and engineering evaluation of the water in the lube oil system. The inspectors observed various portions of the maintenance activities and had no concerns. Coordination and execution of maintenance activities on the Unit 2/3 and Unit 3 diesel generators were good.

c. Safety Relief Valve Testing

Following a concern over the adequacy of safety relief valve testing at the LaSalle station, the inspectors reviewed the method used for scheduling testing at Dresden station. The test method at Dresden included 50% of the safety relief valves in one refueling outage, the other 50% in the next outage. Each valve was therefore tested in alternate outages with a periodicity of 3 to 4 years depending on refueling intervals. This fell within the required 5 year period. The inspectors had no concerns.

No violations or deviations were 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. Failure to Submit Licensee Event Reports

Numerous failures and drifts of reactor water level instruments are discussed in paragraph 8. The licensee submitted licensee event reports (LERs) in January and October 1993 when multiple contacts were found outside TS tolerances, concurrently. However, the licensee did not submit LERs for the remaining surveillance 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 (17 over 6 months) random failures of these switches were indicative of a recurring generic equipment problem. Failure to submit LERs is considered a Violation of 10 CFR 50.73 (50-237/94002-02(DRP)).

b. Poor Quality of Licensee Event Report 237/93031, Revision 0

In January 1994, the licensee submitted LER 50-237/93031, "Reactor Vessel Level Instrumentation Found Outside of Technical Specification Due to Instrument Drift." The inspectors noted the following weaknesses in the report:

- The licensee stated "several" drifts occurred with this instrument since installation. Within a seven month period, the identical switch drifted seven times.
- The licensee listed one previous event (LER 249/93019); however, three LERs were written in 1993 regarding reactor water level switches out of tolerance. Also, no related problem identification forms (PIFs) were referenced.
- No previous industry experiences were provided. A LER submitted in January 1993 on reactor water level instruments listed 129 previous industry failures.
- The licensee stated LERs will be submitted for complete failures of logic and all other drifts or failures would be reported in a supplemental report at the end of the year. This action was inconsistent with 10 CFR 50.73(f).

The inspectors discussed these observations with the regulatory assurance supervisor. The inspectors noted improvement in a supplemental report of a related LER submitted in February.

c. Diesel Generator Cooling Water Pump Degraded Flow

On August 27, 1993, during a routine Unit 2/3 DG test, the licensee noted decreased cooling water (DGCW) flow. The design flow rate was 840 gpm at a service water temperature of 95°F; however, only 640 gpm was achieved. At the time of the surveillance, all four CCSW pumps were supplying water to a discharge header common to the DGCW pumps. After securing two CCSW pumps, the DGCW flow rate increased to 870 gpm. The licensee declared the Unit 2/3 DG inoperable for further engineering evaluation.

On August 31, the licensee performed an engineering operability evaluation which showed that a minimum DGCW flow of 640 gpm at 87°F was required to maintain Unit 2/3 DG operability. The DG was declared operable. On October 8 the temperature limit was lowered to 83°F based on information obtained during a Unit 2 DG test. On December 20 the licensee performed a more detailed calculation and determined the maximum DGCW intake temperature to be 86°F at 640 gpm. The inspectors reviewed these calculations and had no concerns.

On January 19, 1994, the licensee performed a DGCW hydraulic and thermal capacity test to confirm the latter calculation results. The inspectors will evaluate the test results during review of the associated licensee event report (LER 237-93018, revision 2).

d. Motor Operated Valve Testing

The inspectors witnessed portions of the differential pressure test of motor operated valve 3-1501-13B, low pressure coolant injection minimum flow valve. The test was well coordinated and had sufficient resources to minimize the time equipment was inoperable. The inspectors reviewed the test documentation and had no concerns with the differential pressure test. However, during the course of the review some concerns were identified as discussed in paragraph 3.a.

One violation was identified for the failure to submit licensee event reports.

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.

  The station has implemented a composite cleaning crew, consisting of personnel from all station departments. The crew commenced cleaning the Unit 3 (elevation 517) and appeared to be effective in both cleaning and decontaminating the overhead areas.

Plant Support Related Observations

Information Notice Backlog

The inspectors reviewed the licensee's actions in response to Information Notice 89-77, Supplement 1, "Debris in Containment Emergency Sumps and Incorrect Screen Configurations," which was issued December 3, 1993. As of February 18, 1994, the licensee had not assigned this information notice for action. Therefore, no action had been taken on this item to date. A further review showed numerous information notices were backlogged in the regulatory assurance department. This demonstrated a weakness with regards to disseminating potentially safety significant information to the engineering personnel. The licensee's inspection of the emergency sumps and screens and subsequent actions is an Inspector Follow-up Item (50-237/94002-03(DRP)).

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.

The inspectors reviewed the licensee's problem identification forms (PIFs) to monitor the conditions related to plant or personnel performance and potential trend. The inspectors noted more safety significant PIFs were being submitted by licensee personnel. Also, through the PIF process licensee personnel identified numerous opportunities to enhance current programs. However, the licensee did not recognize the adverse trend on the reactor water level instruments.

No violations or deviations were identified.

8. Reactor Water Level Switches Out Of Tolerance

a. Design

The emergency core cooling systems (ECCS) were designed to actuate at certain reactor water levels to mitigate the consequences of an accident. Each unit had four level instruments. Each instrument had two mercury switches and associated contact pairs which sensed "low-low" reactor water level and initiated ECCS equipment when the one-out-of-two twice logic was satisfied. One additional set of contacts on two level instruments provided the high reactor water level isolation signal for the high pressure coolant injection (HPCI) system in a two-out-of-two logic.

Technical specification (TS) tables 3.2.1 and 3.2.2 required the low-low level switches to actuate between 88 and 84 inches from the top of active fuel. This value corresponded to -59 and -55 inches medium range. The licensee set the switches to actuate at -57 inches. The TS required two channels per trip system operable. One inoperable channel in each trip system required a unit shutdown.

The Updated Final Safety Analysis Report (UFSAR) Section 7.3.2.4 stated HPCI automatically isolated upon an increase in normal operating level of about 12 inches of water. This corresponded to +48 inches on the medium range and was 90 inches below the steam line outlet. The licensee set the switches to actuate at 46 inches, ± 2 inches.

b. Equipment History

As discussed in Inspection Reports 50-237/92036 and 50-237/93034, the ECCS level switches had a history of failures to actuate within the technical specification limits. Since 1991, the instruments were out-of-tolerance or completely failed to actuate at least 50 times. The Dresden Vulnerability Assessment Team reviewed the history between 1989 and 1991 and determined that twenty five percent of the 30 out-of-tolerance (OOT) events were complete failures to actuate. The 1992 through 1994 data is summarized below:

Unit 2

Number of switches found outside required values	1992		1993		1994	
	Total OOT	Failed to actuate	Total OOT	Failed to actuate	Total OOT	Failed to actuate
TS (-55 to -59)	4	0	14	5	0	0
UFSAR design (<+48) test limits (44-48)	0	0	3	1	0	0

Unit 3

Number of switches found outside required values	1992		1993		1994	
	Total OOT	Failed to actuate	Total OOT	Failed to actuate	Total OOT	Failed to actuate
TS (-55 to -59)	8	2	7	0	1	1
UFSAR design (<+48) test limits (44-48)	1	0	5	0	0	0

As shown above, in 1993, the instruments were found outside TS and UFSAR tolerances on 29 occasions. Seventeen of the 1993 events occurred on Unit 2 after instrument replacements. Details of the 1993 failures are listed in Attachments 1 and 2.

c. Safety Significance:

The routine drift and failures of the level instruments was significant. Between June and December 1993 instrument mechanics performed seven surveillances on the ten Unit 2 switches. This corresponded to a total of seventy individual switch challenges. Of the 70 challenges, the switches failed to actuate six times and were found outside the expected manufacturer drift twice. This equated to a potential individual failure rate greater than 10% for Unit 2. The actuation logic was operable because in each event only one switch in the trip logic was found inoperable. However, in January 1993 the Unit 3 low pressure coolant injection (LPCI) initiation would have been delayed since the as-found settings of two switches were found non-conservatively out-of-tolerance.

The design requirements for ECCS systems were defined in 10 CFR 50.46 and described in the UFSAR. The automatic initiation and isolation function actuated by the level switches were assumed in the UFSAR in the following accident scenarios:

1. Section 15.6.5. Loss of coolant accidents resulting from piping breaks inside containment: ECCS was assumed to automatically actuate on <u>either</u> low-low water level or high drywell pressure.

2. Section 15.2.7. Loss of normal feedwater flow: HPCI initiated at low-low level setpoint. (The analysis determined that without HPCI makeup level would remain five feet above core.)

3. Section 15.6.1. Inadvertent opening of a safety/relief valve: During a concurrent loss of offsite power, HPCI automatically actuated on low-low level.

4. Section 15.5.1. Inadvertent initiation of HPCI: vessel level increases until HPCI pump turbine was tripped by hi level signals.

The inspectors queried the licensee regarding the impact of the instrument performance on the Individual Plant Evaluation (IPE). The licensee determined the failure rate for 1992 and 1993 to be 10^{-4} per hour, whereas the failure rate assumed in the IPE was 5×10^{-6} per hour. Level switch failures affected the assumed failure rate of the common actuation system (CAS) in the IPE. The CAS consisted of the low-low reactor water level and high drywell pressure initiation logic. The level switch logic dominated the CAS failure sequence. The baseline IPE has a core damage frequency (CDF) of 1.85×10^{-5}/year. The bounding case for level switch failures (failure of CAS) resulted in a CDF of 4.35×10^{-5}/year, an increase of 135 percent.

In January 1993, the as-found settings of two switches affected the LPCI actuation logic and would have initiated late. The licensee determined that assuming this condition existed for 10 days during the reactor years of operation, this event increased the CDF by 1 percent.

d. <u>Inadequate Long Term Corrective Actions</u>

The licensee documented the instrument out-of-tolerances in numerous deviation reports (DVR) and PIFs. In 1989 a feasibility study was initiated to review possible design changes to improve equipment performance. The study was completed in January 1991; however, no actions were taken with respect to the these instruments. A DVR written in mid-1991 referenced another feasibility study. The inspectors queried the licensee regarding the status of that study; however, it appeared the study had not been completed. Licensee Event Report 237/93001 stated a feasibility study was initiated to review possible design change; however, it was not known whether that was a new effort or a reference to the 1991 study. After the inspectors identified the 1993 adverse trend, the licensee initiated a new engineering study, documented in LER 237/93031. Discussions with the site engineering operations support supervisor indicated that during 1993 site engineering was working on a resolution to the drift problems; however, the site engineering actions were isolated from the station engineering organization. In addition, the magnitude of the problem was not known until a detailed operability evaluation was performed after the inspectors questioned the adverse trend.

Although some action was initiated by the licensee to resolve the long term equipment reliability problem, the licensee failed to initiate actions commensurate to the safety significance.

Also in 1989, the licensee initiated a TS change to Table 3.2.1 as part of the TS improvement program. Due to other TS changes and the TS upgrade program, this particular TS change request was not submitted to the NRC until March 1993. Since the licensee was unaware of the significance of the adverse trend, the TS amendment was not given a high priority.

e. <u>Failure to Perform Root Cause Determinations</u>

During the March 1993 Unit 2 outage, the licensee replaced the instruments with new like-for-like instruments. The inspectors reviewed the maintenance work package and had several concerns regarding the instrument quality and resolution of problems identified during installation. Specifically:

1. The instrument technicians identified several manufacturing flaws such as incorrect pipe nipple lengths and cold soldering flaws with the newly purchased instruments. These concerns were corrected prior to installation.

2. Two instruments (2-263-72B and -72D) required replacement of spiral wells. The spiral wells were essential to proper equipment operation.

3. Instrument 2-263-72A required a replacement of the magnetic hub assembly and mercury switch associated with contact 7-8. The root cause of the switch problem was not evaluated. This contact failed to actuate during its first three surveillance tests following installation.

4. Instrument 2-263-72C required a replacement of the mercury switch associated with contact 5-6 due to excessive drifting problems during bench testing. The cause of the drift was not investigated. This contact drifted outside TS limits in seven of eight surveillances in 1993 following installation.

5. The receipt inspection and testing consisted of actuating the switches once and did not challenge the repeatability of testing results. The receipt inspection did not identify the manufacturing problems stated above.

The licensee did not determine the root causes to the above problems encountered during installation. As a result, it appeared that identical problems occurred during the routine surveillances after installation.

The inspectors reviewed operator log books, maintenance work requests, completed monthly surveillances and integrated reporting program documents to determine how problems identified during the surveillances were addressed. The inspectors also interviewed several instrument technicians and witnessed two monthly surveillances. The inspectors observed that few root cause determinations were made for failures during routine surveillances. Specifically:

1. The instrument mechanics routinely attempted to adjust or replace switches when the as-found readings were outside TS limits. The replaced switches were not retained for further investigation. These actions prevented the licensee from determining if the switches were faulty or mispositioned in the switch holder.

2. PIFs and Level IV investigations were initiated for most of the events listed in Attachment 1 and 2. The cause codes listed in these documents included component aging, setpoint drift, and comments on instrument accuracies.

The licensee did not perform root cause determinationsfor identified out-of-tolerances during surveillance testing.

f. <u>Failure to Identify Significance of Adverse Trend and Individual Equipment Performance</u>

Instrument maintenance personnel tracked instrument performance on individual graphs depicting as-found and as-left data for each month. Problem identification forms (PIFs) were written for as-

[illegible] as- [illegible] this [illegible] PIF investig[illegible] resulting [illegible] the [illegible]

[illegible] and out [illegible] the [illegible] late. [illegible] the 1992 [illegible]ate.

2. The as-found setpoints for instrument 3-263-72B were outside [illegible] associated [illegible] the [illegible] below TS [illegible]

[illegible] outside [illegible] 7-8, [illegible] February 19[illegible], the licensee recognized this adverse trend and [illegible] of the spiral well assembly during the next surveillance.

The licensee's integrated reporting program failed to identify the Unit 2 and individual instrument [illegible] trends.

g. Engineering Involvement After Inspectors' Identification

Site engineering [illegible] independent assessment of the [illegible] findings were discussed with [illegible] management. The site engineering review [illegible] reactor water level switches [illegible] determined that [illegible] performed a [illegible] evaluation to [illegible] ability of the ECCS [illegible] analysis study [illegible] assumptions [illegible] plant [illegible].

The setpoint error analysis [illegible] confidence level estimate of the expected error for the instrument corresponded to ± 6.6 inches reactor water level. [illegible] showed that the instruments [illegible] than the [illegible] error with an actual error band corresponding to ± 2.5[illegible] inches. However, this was still greater [illegible] inches.

The licensee conducted a probabilistic risk assessment as discussed in paragraph 8.c. The licensee concluded the instruments were operable based on the assessment results and the most recent surveillances where no instruments were found out-of-tolerance. Site engineering initiated several compensatory actions to ensure operability until long term corrective actions were completed. These actions included developing inspection criteria, predictive trending, identifying acceptable performance criteria and actions if outside this guidance, and establishing a new tolerance band following TS amendment approval.

h. Summary

The reactor water level instruments have been a long-standing problem at Dresden. The licensee initiated activities to resolve the issue; however, the pace of these actions was not commensurate with the safety significance of the problem. The significance of the adverse trend on Unit 2 was not identified by the licensee. Although PIFs were written, the general adverse trend and individual performance trends were not identified. Root causes of the instrument drifts and failures were not determined. Failure to promptly identify, determine root cause, and correct recurring reactor water level switch problems is contrary to 10 CFR 50, Appendix B, Criterion XVI and is considered an Apparent Violation (50-237/94002-04(DRP)).

One apparent violation for inadequate corrective actions was identified.

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

(Closed) Unresolved Item (50-237/93034-02(DRP)): Review of corrective actions for recurring reactor water level instrument drifts. This item is discussed above in paragraph 8. The subject of corrective actions for recurring instrument drifts was identified as an Apparent Violation in this report and this tracking item is closed.

(Closed) Unresolved Item (50-237/93034-03(DRP)): Recurring reactor water level instrument drifts not reported. This item is discussed above in paragraph 5.a. The subject of reporting repetitive drift problems was identified a Violation in this report and this tracking item is closed.

(Closed) Inspector Follow-up Item (50-237/93017-01(DRP)): Small fires caused by heat treatment operations. The inspectors reviewed the licensee's corrective action, which consisted of tailgate training of the events, and found the actions appropriate. This item is closed.

Temporary Instruction 2515/065: TMI Action Plan Requirement Follow-up
The inspectors observed various portions of the installation and testing and verified operability of the Unit 2 reactor vessel water level indication system (RVLIS). This item is closed for Unit 2. The licensee intends to install RVLIS on Unit 3 during the March 1994 refueling outage. This item remains open for Unit 3.

One previously unresolved item was identified as a Violation in this report and is discussed in paragraph 5.a. One previously unresolved item was identified as an Apparent Violation in this report and is discussed in paragraph 8.

10. Licensee Event Reports (LERs) Follow-up (92700)

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

Unit 2

(Closed) LER 237/93030, Revision 0: Station Procedure for Containment Purging Allow Venting Through the Reactor Building Ventilation System. This event was the subject of Unresolved Item 50-237/93034-01. This LER is closed.

(Closed) LER 237/93031, Revision 0: Reactor Vessel Level Instrumentation Found Outside of Technical Specification Due to Instrument Drift. This event is discussed in paragraph 8; the quality of this LER is discussed in paragraph 5.b. This LER is closed.

Unit 3

(Closed) LER 249/93001, Revision 1: Emergency Core Cooling Level Indicating Switch Out of Calibration due to Instrument Drift. This revision discussed new corrective actions resulting from increased instrument failures. This event was identified as an Apparent Violation in this report and this tracking items is closed.

(Closed) LER 249/94003, Revision 0: Unit 3 Reactor Vessel Level Instrumentation Found Outside of Technical Specification Limits Due to Setpoint Drift. The 263-72B contacts 7-8 failed to actuate during a routine surveillance. The inspectors disagreed with the stated cause of instrument drift. The instrument failed to actuate completely due to an equipment problem, not traditional setpoint drift. The subject of root causes for failed instrumentation was identified as an Apparent Violation in this report and this tracking item is closed.

No violations or deviations were identified.

11. [illegible]

[illegible]
Reactor Safety [illegible]
[illegible]
discussed [illegible] reduce
operator [illegible]
[illegible]

No violations or [illegible] identified.

12. [illegible]

The inspectors met with licensee representatives (denoted in Paragraph 1) throughout the inspection period and at the conclusion of the inspection on [illegible] 13, [illegible], to summarize the scope and findings of the inspection [illegible] acknowledged the inspectors' comments. The inspectors also discussed the likely informational content of the inspection report [illegible] documents or processes reviewed [illegible] not identify any such [illegible] proprietary.

Attachment 1: UNIT 2 Emergency Core Cooling System Reactor Water Level Switches

INSTRUMENT	CONTACT SWITCH	INITIATION LOGIC	DATE	AS FOUND LEVEL (INCHES)	REQUIRED LEVEL (TS/FSAR) (See #1)	PROBLEM (F)AILURE (D)RIFT (See #2)	NOTES
263-72A	7-8	CS, ADS and DG	06/11/93	(-88.6) wouldn't trip	-59 (TS)	F	B logic was operable and would have initiated ECCS.
			07/12/93	didn't trip		F	B logic was operable and would have initiated ECCS.
			08/09/93	didn't trip		F	B logic was operable and would have initiated ECCS.
263-72B	3-4	* HPCI ISOLATION	08/10/93	42.9	+48 (FSAR)	D	
			09/03/93	27.6		F	
			10/01/93	didn't trip		F	Operator action necessary to isolate HPCI on hi level
	5-6	LPCI	07/15/93	didn't trip	-59 (TS)	F	A logic was operable and would have initiated ECCS.
263-72C	5-6	LPCI and HPCI	06/11/93	-60.8	-59 (TS)	D	
			07/19/93	-60.4		D	
			09/03/93	(-68.4) may not have tripped		F	As found setpoint was approximately equal to the elevation of variable leg sensing tap.
			10/01/93	-62.5		D	
			10/29/93	-52.3		*	Conservative setting
			11/23/93	-65.5		F	
			12/22/93	-52.8		*	Conservative setting
	7-8	CS, ADS and DG	10/01/93	-62.5	-59 (TS)	D	
			10/29/93	-52.5		*	Conservative setting
			11/23/93	-62.9		D	

Attachment 2: UNIT 3 Emergency Core Cooling System Reactor Water Level Switches

INSTRUMENT	CONTACT (SWITCH)	INITIATION LOGIC	DATE	AS FOUND LEVEL (INCHES)	REQUIRED LEVEL (TS/FSAR) (See #1)	PROBLEM (F)AILURE (D)RIFT (See #2)	NOTES
263-72A	3-4	*HPCI ISOLATION	01/28/93	44.2	+48 (FSAR)	D	
	5-6	LPCI and HPCI	01/13/93	-59.9	-59 (TS)	D	ECCS initiation delayed (both A & B logic OOT.)
	7-8	CS, ADS and DG	01/13/93	-59.9	-59 (TS)	D	
263-72B	3-4	*HPCI ISOLATION	01/28/93	41.4	+48 (FSAR)	D	
			02/25/93	50.5		D	
			04/21/93	44.2		D	
	5-6	LPCI	01/13/93	-59.7	-59 (TS)	D	ECCS initiation delayed (A & B logic OOT)
			02/25/93	-59.9		D	
	7-8	CS, ADS and DG	06/16/93	-61.3	-59 (TS)	D	
			07/14/93	-65.4		F	
			08/16/93	-66.9		F	
			01/19/94	didn't trip		F	A logic was operable and would have initiated ECCS

NOTES

1. The technical specification limit is +84 inches above the top of active fuel which corresponds to -59 inches on the Instrument range.

2. DRIFT is defined as ± 6.6 inches from ideal setpoint (-57 or +46 inches). A FAILURE is considered any setpoint outside this drift band or a failure to actuate.