U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/91025(DRP); 50-249/91025(DRP)

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

Licensee: Commonwealth Edison Company

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

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: August 29 through October 21, 1991

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11/15/91
Date

Inspection Summary

Inspection from August 29 through October 21, 1991 (Report Nos. 50-237/91025(DRP); 50-249/91025(DRP))
Areas Inspected: Routine unannounced safety inspection by the resident inspectors, regional based inspector, and an Illinois Department of Nuclear Safety inspector of licensee action on previously identified items; operational safety; monthly maintenance; monthly surveillance; pre-outage preparations; preparation for refueling; events followup; training effectiveness; safety assessment and quality verification; and site visits by NRC staff.
Results: Two non-cited violations, three unresolved items and two open items were identified.

Plant Operations

Performance of licensed operators during transient conditions was good. Weaknesses in the management directives continued from the previous inspection period. Procedural adherence during routine activities was also a weakness.

Maintenance/Surveillance

Maintenance activities were properly performed. Preparation for the upcoming Unit 3 refueling outage has proceeded satisfactorily. Numerous enhancements in the planning process for this outage have been implemented compared to the 1990 Fall Unit 2 outage. However, a number of improvement actions are still in development. Shutdown risk was factored into outage scheduling but specific actions to implement lessons learned from the Vogtle event before the upcoming Unit 3 refuel outage appeared minimal. The effectiveness of all the improvement actions to improve outage performance will require observation of the implementation of those initiatives during the Unit 3 outage. Procedural weaknesses in surveillance procedures were noted.

Emergency Preparedness

The licensee staff properly identified emergency conditions and activated the emergency plan when appropriate. Emergency response centers were manned in a timely manner and properly functioned.

Safety Assessment and Quality Verification

A strong corrective action with clear goals to identify contactors omitted from surveillance testing was in progress. However, the program for assuring management tours were being conducted, was weak.

Engineering and Technical Support

Good support to troubleshooting and evaluating scram causal factors was exhibited. A weakness in fuse coordination for modifications was noted.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
L. Gerner, Technical Superintendent
*J. Kotowski, Production Superintendent
E. Mantel, Services Director
*D. Van Pelt, Assistant Superintendent - Maintenance
*J. Achterberg, Assistant Superintendent - Work Planning
G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
M. Korchynsky, Operating Engineer
*B. Zank, Operating Engineer
*R. Stobert, Operating Engineer
T. Mohr, Operating Engineer
M. Strait, Technical Staff Supervisor
L. Cartwright, Q.C. Supervisor
J. Mayer, Station Security Administrator
*D. Morey, Chemistry Services Supervisor
F. Kanwischer, Services Superintendent
K. Kociuba, Quality Assurance Superintendent
*D. Lowenstein, Regulatory Assurance Analyst
*L. Jordan, Office Supervisor
*B. Viehl, Site Supervisor, ENC
*S. Couillard, Nuclear Quality Programs
*T. Gallaher, Nuclear Quality Programs
*D. Gulati, Master Instrument Mechanic
*B. Geier, Master Maintenance Mechanic

*Denotes those attending the exit interview conducted on October 21, 1991, and at other times throughout the inspection period.

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, operators, shift engineers and foremen, electrical, mechanical and instrument maintenance personnel, and contract security personnel.

2. Previously Identified Inspection Items (92701 and 92702)

a. (Open) Unresolved Item (50-237/91022-11(DRP)). Safety evaluations for certain classes of procedures were not being routed to the Offsite Nuclear Safety Group (OFSG) for review contrary to the requirements of Dresden Administrative Procedure (DAP) 9-02, "Procedure and Revision Processing," Revision 24, Step F.7.c(4). This DAP had been previously changed in response to an early 1990 Nuclear Quality Programs (NQP) finding of a similar nature, to require procedures which have a completed Safety Evaluation Form 10-2C to be transmitted to the OFSG. The submittal was to ensure the

Technical Specification 6.1.G.1.a required OFSG review of safety evaluations for changes to procedures as described in the Safety Analysis Report (SAR) were performed. Through a review of the procedure distribution log and the corresponding procedure history files, the inspector identified numerous examples of Dresden Instrument Surveillances (DIS), Dresden Operating Procedure (DOP) System Checklists, Dresden Sample Building Procedures (DSBP), and Special Procedures (SP) with associated Form 10-2C that had not been sent to the OFSG for review. Although the administrative procedure had been changed, management failed to revise the instructions associated with the distribution log.

The NQP followup audit of the original finding verified through interviews with administrative personnel and the OFSG representative that procedures were being sent and received. However, a more specific sample audit was not conducted at the time. Following identification of the deficiency by the NRC, an already planned OFSG audit was conducted by NQP. In accordance with NPQ policy, a second followup review of this previous NQP finding was conducted. Since specific audit plans had not been formulated at the time of the NRC inspection, it could not be positively determined whether the licensee would have performed a specific sample audit on the second followup without knowledge of the NRC identified item. During the second followup, NQP confirmed the NRC findings and found additional examples of safety evaluation forms not transmitted to the OFSG.

In response to the occurrence, the licensee reviewed the event with clerical management to insure awareness of requirements, presented this event at a station tailgate, and developed a lessons learned notification. The latest revisions to the missed procedures were also submitted to the OFSG. In addition, a logging program for OFSG transmittals was developed.

The actual safety significance of not having the OFSG review was minimal. The required OFSG reviews were post-change reviews and the procedures had already received on-site review. Also, the procedure changes in question did not affect the SAR. Therefore, Technical Specification 6.1.G.1.a. did not require OFSG review.

The failure to ensure adequate implementation of corrective actions to the previous NQP finding such that the deficiency was not corrected is considered to be a violation of 10 CFR 50, Appendix B, Criterion XVI. However, a Notice of Violation is not being issued in accordance with the criteria of 10 CFR 2, Appendix C, Section V.A.

The second part of this unresolved item remains open pending completion of NRC review of licensee actions in response to the OFSG identification of the Unit 2 high pressure coolant injection steam line flow isolation differential pressure transmitter not having periodic calibration requirements.

b. (Closed) Unresolved Item (50-237/91022-09(DRP)): Inadequate surveillance procedures for source range and intermediate range monitors. The licensee identified the contacts not being tested as part of an integrated program to identify deficiencies of this nature. The inspector reviewed the licensee's integrated program which included drawing enhancements, procedures revisions and contact verifications on fifteen systems. This matter is considered a violation of Technical Specification 6.2.A.7. However, a Notice of Violation is not being issued in accordance with the criteria of 10 CFR 2, Appendix C, Section V.A. This recognizes that completion of the integrated contact review program by May 1, 1991 is the corrective action to the violation and followup on completion of this corrective action is considered an open item (50-237/91025-01(DRP)).

No other violations or deviations were identified in this area.

3. Operational Safety Verification (71707)

The inspectors reviewed the facility for conformance with the license and regulatory requirements and that the licensee's management control system was carrying out its responsibilities for safe operation.

On a sampling basis, the inspectors observed control room activities for proper control room staffing; coordination of plant activities; adherence to procedures or Technical Specifications; operator cognizance of plant parameters and alarms; electrical power configuration; and observed the frequency of plant and control room visits by station managers.

While in the control room various records, such as tagouts, jumpers, shiftly logs and surveillance, daily orders, maintenance items, various chemistry and radiological sampling and analysis were reviewed.

During tours of accessible areas of the plant, the inspectors made note of general plant and equipment conditions. General areas of review included ESF system valve and electrical power alignments, radiation protection practices, security plan implementation, plant housekeeping or cleanliness and control of field activities in progress.

a. Engineered Safety Features (ESF) Systems

Unit 2

2 Emergency Diesel Generator System
Low Pressure Coolant Injection System
2 & 2/3 Diesel Generator Cooling Water System
Isolation Condenser
Control Building Emergency Air Filtration Unit

Unit 3

Low Pressure Coolant Injection System
Core Spray System
3 Diesel Generator Cooling Water System
Isolation Condenser

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

Station maintenance activities affecting the safety-related systems and components listed below were observed and reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review: the Limiting Conditions for Operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

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

The following maintenance activities were observed and reviewed:

Unit 2

2B Reactor Building Ventilation Sample Pump Replacement
2B Condensate/Condensate Booster Pump Overhaul
Unit 2 Thrust Bearing and Thrust Bearing Wear Detector Inspection/Repair

Unit 3

Unit 3 Service Air Compressor
Off Gas Hydrogen Analyzer Repair
125 VDC Battery Charger Repair
No. 3 DG Cooling Water Pump Repair
A Loop LPCI Containment Cooling Heat Exchanger Inspection/Repair
Preventative Maintenance of 4KV breakers

On August 15, 1991, the fire proof material in an existing three inch diameter hole in the Unit 1 control room floor was removed by Fluor craftsmen to facilitate the running of welding leads and subsequently left unattended for a half hour time period. The Unit 1 and Unit 2/3 control rooms were contiguous and were not separated by a rated fire barrier. The Unit 1 control room floor was of concrete construction supported by exposed structural steel and had no fire rating. However, the floor was evaluated in the Safe Shutdown Analysis as a fire barrier and deemed to be adequate to limit the spread of fire either into or from the control room area. The individual responsible for the continuous fire watch had received general training on fire barriers. That individual, who had been working on the Unit 1 control room modification for approximately a year, had been informed at the start of this assignment of the need for a continuous fire watch when opening holes in the floor. Upon identifying a problem with the welding equipment, the individual left the control room area forgetting about the fire watch requirements. The degraded fire barrier was subsequently identified by a Shift Foreman.

Dresden Administrative Technical Requirements (DATR) 3/4.1.6 allowed one hour to either establish a continuous fire watch or to verify operability of fire detectors and establish an hourly firewatch. Since the degraded barrier was left unattended for only an hour, DATR requirements were not exceeded. Dresden Fire Protection Procedure, DFPP 4175-1, "Fire Barrier Integrity and Maintenance," Revision 5, Step F.1.a(2), however, was more stringent than the DATR, by indicating that, in most cases, any work involving breaching of a fire barrier required a continuous fire watch. Step F.3.9 prescribed usage of a Fire Barrier Integrity Checklist for each barrier component affected by a work request or modification. This was to provide control over the degradation and prescribe specific compensatory actions. However, a memorandum from the Technical Staff Supervisor to the ENC Construction Superintendent dated March 12, 1991, indicated that construction work which creates new or affects existing penetrations in Unit 1 control room walls, floor or ceiling, need not be controlled in accordance with the Station's regulatory related program for fire protection. Therefore, no Fire Barrier Integrity Checklist existed for this work. This left only lesser controls from DAP 1-4, "Station Contractor Control," regarding a pre-job walkdown and survey form, which included a fire hazards section. In this case, none were identified. This is considered an unresolved item (50-237/91025-02(DRP)) pending further review of the appropriateness of superseding an on-site reviewed procedure control due to the Technical Staff Supervisor memorandum.

No violations or deviations were identified.

5. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications during the inspection period and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met, that removal and

restoration of the affected components were accomplished, that results conformed with Technical Specifications and procedure requirements were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities:

Unit 2

DOS 2300-1	HPCI Motor-Operated Valve Operability Verification
DOS 2300-3	HPCI System Operability Verification
DOS 6600-1	Unit 2 Diesel Generator Monthly Operability Test
DTS 1600-22	Secondary Containment Leak Rate Test

Unit 3

DOS 700-3	SRM Detector Position Rod Block Functional Test
DOS 700-6	SRM Functional Test Prior to Core Alterations
DOS 2300-3	HPCI Operational Full Flow Test

During the performance of the secondary containment integrity testing on August 26, 1991, the operating authority determined the test procedure acceptance criteria of 0.25" of water average pressure across the reactor building wall at the refuel floor could not be met. The failure was attributed to a test instrument out of calibration. The test was re-performed using more sensitive instrumentation. The test was performed in a number of railway door configurations with one configuration not meeting the test acceptance criteria.

The configuration that failed was the same configuration observed by NRC inspectors on June 24, 1991, at which time the inner railway door was unattended in the open position and the outer railway door was closed but with a degraded bottom seal leaving an approximate 5/8" gap. The as-found condition (inner door open with the outer door closed with a degraded seal) was 0.15" of water pressure across the reactor building wall versus the acceptance criteria of 0.25" of water pressure. A more complete followup and review of this matter will be discussed in a future special inspection report.

No violations or deviations were identified.

6. Pre-outage Review (71707, 61726, and 62703)

The inspectors reviewed licensee planning efforts and actions in preparation for the Unit 3 refueling outage as follows:

a. Schedule Preparation

A review of outage planning methodology indicated that the outage schedule was based upon a model schedule of about 70 days. Upon preliminary establishment of the outage scope, the schedule was

resource loaded and discrepancies between needed and available manpower were identified. This resulted in contracting out of additional work, such as the turbine overhaul and control room recorder upgrades. The inspectors noted that due to the change in the outage start date, the number of mobile maintenance workers available was only half the usual complement. This was also reflected in the amount of contract work. The working schedule was the underlying document for summarizing the aggregate work hours associated with a particular system. The system, along with its hours, were compiled on a "Windows" schedule which showed the system and the work hours expended over a specific period during the outage. The system work periods were integrated into the master outage schedule based on the system availability needs. Some previously designated outage work requests were deferred or scheduled as "on- line" maintenance work. However, these were few in number and of minor significance.

In order to address drywell work interface difficulties encountered during the last refuel outage, the licensee developed an integrated drywell schedule planned by elevations. Also to address previous problems, the outage schedule incorporated contingency plans to accommodate unforeseen changes with the basic outage schedule (i.e. isolation valve LLRT failures). Frequent outage meetings were planned to provide management attention and guidance to the overall outage schedule.

Ample tracking mechanisms were available to status activities preceding the outage, such as contracts awarded, modifications (approvals, designs, packages and reviews) work request packages, and materials. Tracking data was compiled by knowledgeable coordinators and work planners and was frequently updated and issued to station managers. Frequent outage planning meetings were conducted to resolve inter-organizational problems. Outage director's meetings were also conducted to identify and address problem areas. Overview trends such as total work package and material availability were prepared and reviewed in these meetings.

A sample of the modification (mod) packages was selected for review. The packages were being tracked by either the Technical Staff Modification Coordinator or the Technical Staff System Engineer. Associated work packages and materials were also identified and located. In each case, the modification was progressing on schedule. There were discrepancies with material status tracking information; however, material coordinators were aware of material status and it appeared that material timeliness would not impact the work schedule. In most cases, material was found ready for the work to begin.

b. Shutdown Risk Initiatives

In accordance with corporate guidance, the licensee developed specific policy statements to incorporate a shutdown risk philosophy into outage planning. This ensured electrical power and emergency core cooling system availability beyond minimum Technical Specification requirements. Systems such as service water, DC electrical systems, 4KV and 480 Volt electrical systems were summarized on an outage risk summary sheet that contained a brief description of each risk system along with the plans for work on that system during the outage. These systems were integrated into a schedule which outlined the equipment required during critical periods in the outage work. However, the shutdown risk policy was unclear on how it would be utilized for schedule changes. This will be evaluated more fully in a future inspection specifically in regard to licensee actions in conjunction with the Unit 3 diesel generator outage extension. Activities with the potential for draining the vessel, such as bottom head drain line unplugging, reactor recirculation suction line isolation valve work, and control rod drive (CRD) work were detailed on the outage risk assessment schedule. This provided the licensee with the ability to conduct heightened level of awareness (HLA) meetings prior to or during the performance of critical outage work activities. The more obvious activities with the potential for draining the vessel were identified as HLA activities. Less obvious activities such as the reactor building spill event caused by isolating instrument air to the scram pilot solenoids were not. Licensee shutdown risk initiatives were regarded as good by the inspectors considering the short time period available for their development.

The inspectors reviewed licensee actions in response to NRC Information Notice No. 90-25, Supplement 1, "Loss of Vital AC Power With Subsequent Reactor Coolant System Heatup." This Information Notice discussed the need for access and activity control for switchyards in response to the Vogtle loss of power event. In response to the Information Notice the licensee discussed the notice at a substation construction safety meeting to emphasize restricted usage of bucket trucks and to observe all physical clearances near energized equipment. Additional actions were not planned to be completed until after the refueling outage, including a discussion of this issue in operations requalification training, a reading package for mechanical and electrical maintenance departments, and a revision to the substation construction and division safety manual to prescribe an individual to be a guide when backing trucks. The inspectors considered licensee actions in consideration of the Vogtle event to be minimal.

It was noted that during the first day of the refueling outage, September 8, 1991, an unsecured large radwaste shipping cask fell off a truck while being moved from the radwaste building to reactor building truck bay. Although the cask did not fall in the vicinity of powerline structures or transformers, the intended path of the

truck would have taken it near this equipment. Licensee policy for securing of truck loads was not considered in the licensee's review of the Information Notice. Further review of licensee policy for securing truck loads will be reviewed in a future inspection.

c. Operations Initiatives

In response to the emphasis on shutdown risk minimization, licensed operators were trained on this issue in the continuing training cycle just prior to the refuel outage. This included an event based historical perspective to relate the reason for, and importance of, the concern, a general overview of shutdown risk categories, and specific risk minimization initiatives. The training identified abnormal procedure deficiencies in regard to recovery means during shutdown conditions including a discussion of specific scenarios. Existing administrative controls to prevent errors were re-emphasized. Finally, the planned outage schedule was reviewed indicating periods with reduced equipment redundancy. The inspectors regarded this training as a proactive approach toward enhancing operator awareness of this issue.

Operations personnel developed a list of those abnormal operating procedures needing additional instructions for responding to the abnormal conditions while in cold shutdown versus power operation. However, these procedures are not scheduled for revision until after the current refuel outage.

In response to identified operator work practice deficiencies and to provide increased management oversight to prevent recurrence of similar problems, the licensee issued Operations Department Policy No. 27, "Plant Tours By Operations Department Supervision" on May 28, 1991. This policy provided guidelines for supervisor monitoring of equipment and worker performance along with plant and control room cleanliness/material condition. However, a review of control room access data for the period June 1 through July 24, 1991, indicated that this corrective action was not being adequately implemented by at least one crucial management individual. Even discounting for days spent offsite, this individual accessed the control room significantly less than the guidance prescribed in the policy. The inspectors, although regarding the policy as a good initiative, believed the established goals to be minimal. In addition, management, having set certain expectations, was not taking steps to ascertain whether they were being implemented.

Through Dresden Policy Statement No. 39, "Heightened Level of Awareness (HLA) Activities," dated July 1991, the licensee provided a means to identify subject activities and guidance for achieving expectations in this regard. A general definition of HLA activities was presented and a list of specific pre-identified HLA activities

was included. The Operating Engineers were responsible for preparing lists of upcoming HLA activities to be included in the Daily Orders. HLA activities required special briefings and guidelines for such briefings were identified. Implementation and effectiveness of these initiatives will be more fully assessed during the increased activity level of the refueling outage.

d. Maintenance Initiatives

In response to previous work practice problems and to issues raised during the previous station standdown, a work control committee was instituted to review suggestions and formulate corrective actions. This committee consisted of both management and bargaining unit personnel to increase communication and awareness and to establish a working team relationship. As a result of these efforts the following corrective actions were instituted.

In order to increase supervisory oversight of activities, Maintenance Memorandum 100.10, "Conduct of Maintenance Assessments" was issued on July 1, 1991. This prescribed maintenance management performance of field observations to assess working progress at specific intervals. The intent was to establish face to face communication with maintenance personnel and verify that management's expectations were being communicated.

To help ensure adequate pre-job briefings and pre-job and post-job walkdowns, a laminated pocket size guide was developed. This guide listed specific items for discussion in the pre-job briefing and items to verify in the subject walkdowns. In addition, a maintenance job progression and turnover sheet was developed to ensure adequate transfer of knowledge between shifts.

Maintenance also instituted a peer reviewer process consisting of observations of work in progress by work practice committee and pro- committee members to identify poor work practices and weak work control practices. These individuals were given classroom observation training and then accompanied a seasoned work evaluator in the field to gain better observation skills prior to becoming a peer reviewer. The hope was that this would instill a more critical self-review in the evaluators which would spread through peer pressure to the rest of the maintenance organization. The inspector observed the observation training being given and regarded it as beneficial to instilling a critical questioning attitude.

A maintenance work package committee was established with the goal to make work packages more user friendly. Some of the improvements included: (1) standardization of package organization with increased use of divider tabs, (2) removal of extraneous material,

(3) utilization of reference procedures, (4) removal of pre- and post-job checklists which were not required, and (5) separation of modification (mod) work instructions from the modification package design documents, and others. A Work Analyst Handbook for instruction on creating work packages is under consideration. Some of these improvements were observed in the work instructions of modification work packages.

A maintenance group committee was established to improve post-maintenance verifications. The licensee is utilizing a matrix prepared by an industry organization. The matrix takes a type of component and the work performed on that component and relates it to the proper post- maintenance verification required to assure component operability. The matrices are available to work analysts preparing work packages.

A number of other problems had been identified and were being reviewed by the licensee; however, planned corrective actions had not been either completely formulated or implemented by the licensee at the time of the inspection.

Examples included the following:

- Procedures were not being improved or enhanced by procedure users due to lack of knowledge of the requirement to make changes and the methods for doing so.
- Need for better guidance as to expectations for maintenance use and adherence of procedures and independent verification.
- Need for a followup monitoring plan to judge effectiveness of improvement actions.

A review of further actions to address work control practices will be addressed in future inspections as they are instituted by the licensee. Since the majority of these corrective actions were getting underway just prior to or during the inspection of this area, a more detailed review of implementation and effectiveness will be evaluated during observation of refueling outage activities. The inspectors regarded these actions as positive although the formulation and implementation of specific work practice corrective actions appeared slow.

e. Contractor Work Overview

The Engineering and Construction (ENC) organization of Commonwealth Edison is responsible for the oversight of outage work done by contractors. To accomplish this, ENC managers work with plant management on the work scope from which they proceed with contracting out the work and establishing a hiring plan. In discussions with ENC staff, sufficient schedules and computer

tracking systems were available to track jobs and materials. ENC also assigned an engineer to oversee the preparations and performance of each job. On the two modifications sampled, the assigned staff engineers were knowledgeable of the job and the status of preparations required for the work.

f. Technical Staff (Tech Staff) Engineers

The licensee has taken steps to improve control of engineering technical staff overtime. Shift schedules were established using 12 hour shifts for 6 days a week in order to provide coverage for inservice inspection and inservice test activities. Tech Staff Memo, TSM-16, was issued to establish overtime restrictions for tech staff. These restrictions match the NRC guidelines for overtime work.

An overview of reactivity management by tech staff was established via a reactor engineer who was designated to maintain cognizance of plant status and observe reactivity related activities. Tech staff Qualified Nuclear Engineers (QNE) provide fuel move instructions, maintain records, and perform audits of refueling actions. Tech staff QNEs also observe plant startup. The licensee is working on an overview procedure for QNEs and considering a checklist for their use on fuel moves. For other outage activities, systems engineers are included in the writing and directing of modification tests. They are involved informally in the post maintenance test process.

g. Quality Oversight Outage Plans

The Onsite Nuclear Safety Group (ONSG) performed a qualitative assessment of risk for the planned refueling outage schedule. The assessment provided an evaluation of risk contributors, scheduled activities to minimize significant risk situations, and contingencies to bring the scheduled work within acceptable levels of risk. Through attendance at the ONSG presentation to plant management and review of the final report dated August 15, 1991, the inspectors noted that the assessment had resulted in a number of proactive risk based recommendations which were positively received by plant management. The adequacy of the ONSG review of changes in the schedule from a shutdown risk perspective will be evaluated in a subsequent inspection.

The inspectors reviewed the July 31, 1991 Nuclear Quality Programs Overview Plans for the refueling outage. These plans consisted of a list of significant areas on which to concentrate field monitoring/assessment activities. The inspectors noted that the list was primarily based upon Dresden's specific events/experience. However, at the time of the inspection at this area, specific implementation details had not yet been developed. NQP management planned to have these in place prior to the outage such that this area will be evaluated more fully during a subsequent inspection.

A review of Quality Control staffing plans for the outage revealed sufficient personnel certified in appropriate disciplines to provide coverage on all shifts. Appropriate hold and witness points were being incorporated into work packages in accordance with licensee procedures.

A licensee corporate assessment of work planning was performed prior to the refueling outage. The licensee indicated that identified items were minimal in number and safety significance. The formal report of the assessment had not yet been issued at the time of the inspection of this area and, therefore, will be reviewed in a subsequent inspection.

h. ALARA Initiatives

The inspectors interviewed key personnel involved with radiation protection outage planning and reviewed planned measures to be taken during the outage for control of work in the drywell area. The scope of work within the drywell included such projects as vessel bottom drain line unplugging, rebuilding a selected number of control rod drives, and rebuilding and testing of the reactor recirculation B loop suction valve and both shutdown cooling loop suction isolation valves. The licensee planned a dedicated radiation protection coordinator assigned exclusively to the drywell work. This individual was to be in charge of the radiation protection coverage and provide direct supervision of contract radiation technicians. This individual was also to mediate and resolve ALARA related conflicts should they arise between organizations preforming outage work in the drywell.

All requests for protective lead shielding were to be prepared prior to the start of the associated work. In addition, Engineering and Construction (ENC) was to analyze the lead shielding requests for system loading requirements as well as provide the labor to install the lead shielding. This technique departed from the previous Unit 2 outage where each individual work group installed their own shielding. Through consolidating shielding work within a single organization, the licensee hoped fewer man-rem would be expended in shielding placement as the work crews became more familiar, as well as proficient, in their work tasks. Component specific decontamination was to be utilized to reduce work area specific dose.

The licensee also recently acquired a "Drywell Model", which was a replicate scale model of the areas, elevations and components within the drywell, to serve as an informational work planning tool. The model was to be stationed at a location near the drywell entrance so that it could be viewed and studied by all individuals requiring specific as well as general information on entrance and egress routes, material staging routes, and areas where other work was either in progress or was planned.

All radiation pre-job surveys were to be in the form of general radiation work permits (RWPs) and the actual work process was to be addressed and governed under a specific RWP. The general area concept was to reduce the repetitive surveys of areas that normally remain uninfluenced by changes in work activities. General areas were to normally be surveyed twice per working shift while the specific areas that involve welding, grinding, or opening of contaminated systems, or work involving respirators, or special breathing apparatus were to receive dedicated radiation protection coverage.

No violations or deviations were identified.

7. Preparation for Refueling (60705)

The inspector monitored the licensee's activities associated with the preparation for defueling and refueling for the Unit 3 Dresden refueling outage number 12 (D3R12). The inspector reviewed the licensee's refueling procedures to verify congruency between technical specification requirements and limitations disseminated in the refuel procedures. The inspector also witnessed specific equipment surveillance of the source range monitors, intermediate range monitors and refueling interlocks to support fuel movement.

No violations or deviations were identified.

8. Onsite Followup of Events (93702)

a. A recently completed electrical distribution safety functional inspection (EDSFI) expressed concern on the ability of control circuits for motor operated valves to perform in a degraded voltage condition. The licensee had minimal design documentation to support motor performance at the degraded voltage setpoint. In response to these concerns the licensee, using engineering judgement, selected bounding case motors for testing. Test results on six safety-related valves to date have identified one valve on Unit 3 that failed at the 95 VAC acceptance criteria. The valve, the torus cooling discharge valve in the LPCI system, was declared inoperable, its motor contactors replaced, and retested satisfactorily. Subsequently, two other motor contactors in valves on the Unit 2 LPCI system were replaced for the same reason.

b. On August 17, 1991 Unit 3 scrammed from 56% power during stop valve testing when the turbine tripped on reverse power. The reverse power condition was caused by closure of all six combined intercept valves to the low pressure turbine stages reducing generator output below house loads demand. Closure of the six valves was due to a momentary low hydraulic pressure condition on the common header of the emergency trip system when the fast acting solenoid valve to the stop valve being tested failed.

When the Unit 2's onsite electrical distribution system automatically shifted to the reserve auxiliary transformer a low voltage condition occurred at the safety related 4160 VAC buses. This low voltage condition was not sufficient to cause actuation of the degraded grid relays separating the safety buses from the grid and starting the emergency diesel generators to supply power to the safety buses. However, the bus voltage was low enough to require compensatory operator action to a recently identified EDSFI concern associated with a non-conservative setpoint of the degraded grid relays. Operators did not immediately recognize the need for compensatory measures since the low voltage condition occurred one second after the scram.

Licensee management direction for accomplishing the compensatory measures was an operating order. This order was not prepared with the intent that a scram or transient would be in progress when the low voltage condition existed. Therefore, given the mechanism for identification of the low voltage condition (an alarm typer) and the instructions provided it was unreasonable to expect the operators to immediately identify the low voltage condition.

Subsequently, operators did identify the low voltage condition but actions to clear the low voltage condition took greater than one hour. Management expectations were that these actions would be implemented immediately.

The fast acting solenoid was replaced and the operator instructions on identifying a low 4KV bus condition were significantly strengthened. Also, shift personnel were briefed on the need to take timely action.

c. On August 25, 1991, a Unit 2 turbine generator trip occurred at 38% power from an activation of the thrust bearing wear detector relay. Several Group I and Group II primary containment isolation valves failed closed following the automatic transfer of plant electrical loads to the reserve auxiliary transformer. Additionally, five of eight 120 VAC MSIV pilot solenoids de-energized. The valve actuations were caused by an apparent momentary low voltage condition on the essential 120 VAC bus. Region based inspectors were dispatched to review this condition and the results of their inspection will be documented in a future resident inspector report.

d. On August 26, 1991, the Unit 2 turbine was placed back in service to perform troubleshooting as to the cause of the previous day's turbine trip. At 1114 and 28% power the turbine thrust bearing wear detector actuated again tripping the turbine. The pressure oscillation at the steam line low pressure switches tripped the switches closing the main steam isolation valves. Closure of the MSIVs caused the reactor to scram. Station loads were being carried by the reserve auxiliary transformer. Therefore, the 120 VAC bus low voltage condition was not experienced following the turbine trip.

Subsequent inspection of the wear detector identified no abnormalities and the thrust bearing was inspected. During this inspection the licensee determined that the thrust bearing housing was improperly installed. The improper installation allowed excessive movement of the bearing which caused appropriate actuation of the thrust bearing wear detector. Apparently, the improper installation was caused by inattention to detail by maintenance personnel, at the conclusion of the Unit 2 refueling outage in February 1991.

e. On August 30, 1991, the Unit 2 reactor was restarted and the turbine synchronized to the electrical grid for the purposes of turbine testing and to confirm that pressure oscillations in the steam lines at the location of the pressure switches were of enough magnitude to cause their actuation. At 2009 the turbine was manually tripped from 28% power and a Group 1 isolation (closure of the MSIVs) occurred. Special test equipment recorded the pressure oscillations and proved that the oscillations were sufficient to cause the low pressure trip. Additional testing at different power levels revealed that the large oscillations only occur at low power levels and as the power increases the oscillations become significantly smaller. Since station loads were being carried by the reserve auxiliary transformer, the 120 VAC bus low voltage condition was not experienced following the turbine trip/scram.

f. On September 1, 1991, due to an abnormal lineup of the HPCI Turbine Inlet Drain Pot bypass to the Unit 2 torus, torus temperature exceeded the 95 degrees F Technical Specification limit. However, this was not recognized as a Technical Specification limit by the operating crews until later into the following shift. This is considered an unresolved item (50-237/91025-03(DRP)) pending completion of the NRC review of the circumstances surrounding this event.

g. On September 13, 1991, with Unit 3 in cold shutdown the outer containment purge valve was found to leak excessively during the performance of a routine local leak rate test. The leakage resulted from the mis-alignment of the valve butterfly and the operator. On September 20, 1991, the licensee's investigation revealed an inadequate post maintenance test had been performed following an adjustment of the piston rod on February 7, 1990. This matter will be reviewed by region based personnel at a later date and documented in a future inspection report.

h. On September 21, 1991, Unit 2 operators performed the weekly control rod drive exercising test at 85% power. At approximately 0330 a peripheral control rod would move to the position selected but would drift back out of the core at position 48. Eventually, the rod was scrammed and held in that condition by not resetting the scram signal and pulling the scram fuses.

The licensee postulated, based on a 1979 GE Sill discussing a similar situation, that the collet piston was wedged in the engaged position by dirt or some type of foreign material between the collet

piston and the drive piston. With the collet piston in the engaged position the collet fingers are withdrawn and expanded such that they will not engage in the notches of the drive piston. Thus the control rod always drifts to the fully withdrawn position. In a special procedure written and executed on the afternoon of September 21, 1991, the licensee attempted to flush the collet piston area to remove the foreign material or dirt. This action was successful and the rod was able to be latched and maintained in a designated position. The weekly exercising test was completed earlier during the day with no other abnormalities noted. Also, the licensee performed shutdown margin calculations and verified that the control rod could be at any position within the core and still maintain the required shutdown margin.

During the inspector's review of technical staff historical documentation of control rod performance the inspector noted omissions in the documentation. Interviews with cognizant personnel indicated that the documentation had been engineer dependent over the years. Also, the inspector could not ascertain the acceptance criteria associated with the exercising test. These areas dealing with documentation of control rod drive performance and licensee corrective actions to improving documentation are considered an open item (237/91025-04(DRP)).

i. On September 23, 1991, with all fuel removed from the reactor vessel, Unit 3 experienced a loss of power to the ECCS, Reactor Control and Electrical annunciator panels. The Shift Engineer (SE) promptly and correctly classified the event as an "alert" per station emergency procedures and the technical support center was activated. Throughout the event the SE exhibited good command and control and provided a timely dissemination of information to the control room staff. Overall, control room and technical support center personnel responded professionally to the event and displayed team work. The apparent cause of the annunciator loss was a design modification that prescribed the installation of a common fuse for all three annunciator panels coupled with an error in the under sizing of the fuse. This matter will be pursued as followup to the future LER being prepared by the licensee.

j. On September 25, 1991, with all fuel removed from the reactor vessel, approximately 2,800 gallons of contaminated water was released from the Unit 3 east hydraulic control unit (HCU) bank to the reactor building floor and torus basement. The water spill occurred following the isolation of the control air supply to the scram pilot solenoid valves. Fifteen minutes following the isolation of the air supply, the shift supervisor (SS) was notified of water accumulation on the reactor building floor and an equipment operator (EA) was immediately dispatched. Upon arrival the EA restored air to the scram air header which stopped the leakage. The spill resulted in the contamination of the east side of the reactor

building HCU floor and the torus basement. Decontamination efforts, which began immediately, resulted in the contamination of one station laborer. This is considered an Unresolved Item (349/91025-05(DRP).

k. On October 3, 1991, while Unit 2 was operating at 89% power, the licensee temporarily relieved the reactor operator (RO) from licensed duties. The removal followed an incident in the control room in which the RO refused to cooperate with NRC inspection personnel.

9. Training Effectiveness (41400, 41701)

The effectiveness of training programs for licensed and non-licensed personnel was reviewed by the inspectors during the witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during the review of the licensee's response to events which occurred during the inspection period. Personnel performance weaknesses were evident in the operations area regarding procedural adherence.

No violations or deviations were identified.

10. Safety Assessment and Quality Verification (40500)

On September 27, 1991, an augmented "tail gate" session was held by station management to discuss fourteen recent events some related to poor personnel performance. Management indicated the events spoke of a lack of attention to detail, failure to self check, and a failure to adhere to procedures. Management encouraged plant personnel to pay closer attention to detail, double check actions and adhere to procedures. Plant personnel were afforded an opportunity to discuss potential performance improvement ideas with the management representative.

As corrective action to recent events, the Operating Department incorporated the following enhancements to shift operations:

- Required the use of the phonetic alphabet when alpha numeric designators are used in all operations related communications.
- Required 100% repeat back on all operational related instructions.
- Require 100% procedural reference, including main control room annunciator responses, out-of-service check list and operator rounds.
- Required independent verification on all Technical Specification and safety-related equipment when removed from or placed inservice.

These changes were placed into affect by a Dresden Station Operations Department Letter and will eventually be incorporated in the station Administrative Procedures.

No violations or deviations were identified.

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

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

12. Unresolved Items

Unresolved items are matters which require more information in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. Unresolved items disclosed during this inspection are discussed in paragraphs 4 and 8.

13. Open Items

Open items are matters which: have been discussed with the licensee; will be further reviewed by the inspector; and involved some actions on the part of the NRC, licensee, or both. Open items disclosed during the inspection are discussed in paragraph 2 and 8.

14. Meetings and Other Activities (30702)

a. On July 16, 1991 a management meeting was held at the site between Region III and the licensee. Topics discussed included shutdown risk minimization of outages, outage controls and operational events.

b. On September 6, 1991 a management meeting was held at the site between Region III and the licensee. Topics included maintenance improvements, preparation for the Unit 3 refuel outage, cleanup initiatives for the waste demineralizer vault area and operational events.

15. Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) during the inspection period and at the conclusion of the inspection period on October 21, 1991. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.