April 28, 2000

Mr. Oliver D. Kingsley
President, Nuclear Generation Group
Commonwealth Edison Company
ATTN: Regulatory Services
Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: NRC INSPECTION REPORT 50-237/2000003(DRS); 50-249/2000003(DRS)
DRESDEN NUCLEAR POWER STATION, UNITS 2 & 3

Dear Mr. Kingsley:

On March 23, 2000, the NRC completed an engineering, technical support and corrective action inspection at the Dresden Nuclear Power Station, Units 2 and 3.

The inspection included an assessment and evaluation of engineering support, design change, and modification activities including 10 CFR 50.59 safety evaluations and screenings, as well as training, corrective action and self-assessment activities. Within these areas, the inspectors reviewed procedures and representative records, observed plant conditions, and discussed activities and concerns with members of your staff. The inspection objectives were met; however, were made more difficult by your staff's untimely response to data requested by the team. Specifically, the team requested that information be provided within two days of the written request; however, much of the information requested was not provided to the inspection team until the last two days of the inspection. This also resulted in a subsequent re-exit on March 23, 2000. The enclosed report presents the results of the inspection.

Overall, the inspection results indicated that your engineering and problem identification and resolution activities at the Dresden Generating Station were generally acceptable. Design change and modification packages, for the most part, were comprehensive and technically correct. With some exceptions, 10 CFR 50.59 safety evaluations, calculations, root cause investigations and operability determinations reviewed were acceptable. However, the inspection team determined that system engineering did not always aggressively pursue actions to address long standing engineering issues. Examples included recurrent problems with the low pressure coolant injection (LPCI) total flow indicator, the radwaste solidification building differential pressure, and the LPCI room coolers' design basis. In addition, the inspection team identified that your staff failed to re-analyze the operation of the high pressure coolant injection (HPCI) gland seal leak off (GSLO) system at below the minimum required operating voltages. This was needed to ensure that minimal operating voltages were available for various HPCI equipment when the GSLO system components were upgraded to safety-related status in 1997 and 1998 for Units 3 and 2, respectively.

The inspection team determined that the corrective action program was generally effective in identifying and resolving issues that could degrade plant materiel condition. However, the quality assurance audits and engineering department self-assessments were not fully effective in identifying some of the engineering problems identified by the inspection team. The inspection team noted several long standing recurring engineering issues without timely corrective action. Also, the threshold for problem identification by the engineering staff appeared too high as indicated by the fact that system engineers were aware of existing problems on their systems but failed to initiate problem identification forms (PIFs) until questioned by the inspectors.

Based on the results of this inspection, the NRC has determined that four violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs) consistent with Section VII.B.1.a of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violations or the severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response to this letter, if you should choose to respond, will be placed in the NRC Public Electronic Reading Room (PERR) link at the NRC homepage, http://www.nrc.gov/NRC/ADAMS/index.html.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

/RA/

John A. Grobe, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 50-237/2000003(DRS);
50-249/2000003(DRS)

See Attached Distribution

cc w/encl: D. Helwig, Senior Vice President, Nuclear Services
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P. Swafford, Site Vice President
Robert Fisher, Station Manager
D. Ambler, Regulatory Assurance Manager
M. Aguilar, Assistant Attorney General
State Liaison Officer
Chairman, Illinois Commerce Commission

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	50-237/2000003; 50-249/2000003(DRS)
Licensee:	Commonwealth Edison Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	6500 N. Dresden Road Morris, IL 60450-9766
Dates:	January 24 - March 23, 2000
Inspectors:	Z. Falevits, Team Leader D. Chyu, Reactor Engineer L. James, Reactor Engineer B. Norris, Reactor Engineer D. Schrum, Reactor Engineer N. Shah, Reactor Engineer S. Sheldon, Reactor Engineer
Approved by:	R. N. Gardner, Chief Electrical Engineering Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Dresden Nuclear Power Station, Units 2 and 3
NRC Inspection Report 50-237/2000003(DRS); 50-249/2000003(DRS)

An announced Nuclear Regulatory Commission (NRC) team inspection was conducted from January 24 through March 23, 2000, to assess the effectiveness of the Dresden Nuclear Power Station's engineering organization to perform routine and reactive site activities, including the identification and resolution of technical issues. The inspection team also assessed the effectiveness of Dresden's program for the identification, resolution, and prevention of technical issues and problems that could degrade the quality of plant operations or safety.

Overall, our inspection results indicated that your engineering and problem identification and resolution activities at the Dresden Nuclear Power Station were generally acceptable. With some exceptions, 10 CFR 50.59 safety evaluations, calculations, root cause investigations, and operability determinations reviewed were acceptable. However, the team determined that system engineering did not always aggressively pursue actions to address long standing engineering issues. The corrective action program was generally effective in identifying and resolving issues that could degrade plant materiel condition. However, quality assurance audits and engineering department self-assessments were not fully effective in identifying some of the engineering problems identified by the team. The team noted that the threshold for problem identification by the engineering staff appeared too high, as indicated by the fact that system engineers were aware of existing problems on their systems but failed to initiate PIFs until questioned by the team. The following statements summarize the inspection results:

Engineering

- The team concluded that with noted exceptions, the design control process was properly implemented and design changes and safety evaluations were technically sound and documented in accordance with station procedures (Section E1.1).

- In general, temporary modifications were being appropriately controlled. Licensee self-assessments had identified several process deficiencies that were being addressed. One example where a process deficiency was not identified during the program self-assessment was identified by the team (Section E1.2).

- The team concluded that licensee management bypassed the design change process during implementation of a modification to the Unit 2 high pressure coolant injection (HPCI) turbine stop valve. This was considered a violation of 10 CFR 50, Appendix B, Criterion V. This issue is considered a non-cited violation (NCV) (Section E1.3).

- The team determined that inadequate review of the applicable Safety Evaluation Reports (SERs), while performing the 10 CFR 50.59 screening to change the testing methodology for the average power range monitoring (APRM) channel functional test, resulted in a failure to perform a safety evaluation. This oversight contributed to a reduction in the surveillance periodicity for the reactor protection system (RPS) scram contactors without prior notification to the NRC of the change in licensee commitment and without adequate technical evaluation. This is considered a violation of Technical Specification 6.8. This issue is considered an NCV (Section E1.4).

- The design calculation process was properly implemented and the calculations reviewed were generally technically sound. However, the team identified that the licensee failed to re-analyze the operation of the HPCI gland seal leak off (GSLO) system for minimum required operating voltages when the GSLO system components were upgraded to safety-related status in 1997 and 1998 for Units 3 and 2, respectively. This was considered an Unresolved Item pending licensee re-analysis of available voltages (Section E1.5).

- The team considered the failure to properly translate design information regarding the 12-day low pressure coolant injection (LPCI) restoration criterion into station procedures and the Updated Final Safety Analysis Report (UFSAR) as a violation of 10 CFR 50, Appendix B, Criterion III. This issue is considered an NCV (Section E2.1).

- During a review of a station blackout (SBO) modification, the team determined that the licensee did not exercise appropriate software control. The team identified inconsistencies between the checklist and procedure used to control computer software. In response to the team's observations, the licensee initiated PIF D2000-00731 (Section E3.1).

- The training program for engineers appeared to be adequate; however, the team noted that a LPCI system design requirement was not translated into the operator training program (Section E5.1).

- The team concluded that the Dresden corrective action program was generally effective. However, the team identified some examples where the program did not function as required. Deficiencies previously identified by the Dresden engineering staff were not entered into the corrective action program, and repairs to conditions adverse to quality were canceled by staff personnel after they had been entered into the system. Failure to issue PIFs for three unsatisfactory diesel oil samples for Unit 1 diesel fire pumps is considered a violation of 10 CFR 50, Appendix B, Criterion XVI. This issue is considered an NCV (Section E7.1).

- Root cause investigations and effectiveness reviews were performed for significant problems. The team identified a concern with system engineering's lack of trending of equipment problems (Section E7.5).

- The team determined that the assessments were narrow in scope and focused on specific areas of the programs being reviewed (i.e., valve categorization within the Air-Operated Valve (AOV) program). Based on interviews, the team noted a general engineering staff perception that the self-assessment process did not have full management support (Section E7.6).

- The team determined that the licensee had access to industry operating experience reports and was adequately providing them to station staff. However, these reports were not being reviewed for general station applicability in all cases. In one instance, this resulted in a station Licensee Event Report not being included during a concurrent review of an applicable industry report (Section E8.2).

Report Details

The review of engineering included both design and support engineering activities. Engineering support included system engineering, training, problem resolution and corrective action activities, as well as normal engineering involvement with operations, maintenance, and other plant organizations.

To accomplish this inspection the team evaluated whether engineering was appropriately identifying problems, implementing adequate and timely corrective actions, as well as providing the appropriate depth and attention-to-detail of the engineering work being performed. The team's primary focus was on engineering products completed during the previous years, which were considered representative of the current performance of the engineering organization. The team reviewed engineering processes, which included engineering's involvement in and contributions to identification and resolutions of conditions adverse to quality, modifications (both permanent and temporary), calculations, safety evaluations, operability assessments, and responses to generic industry and NRC concerns.

III. Engineering

E1 Conduct of Engineering

E1.1 Permanent Plant Modifications

a. Inspection Scope (37550)

The team reviewed several modifications and design changes that were installed during the previous two years to evaluate all aspects of the modification process and to verify that the modifications were installed in accordance with program requirements and that the engineering resolutions addressed the issue or concern and were technically sound. In addition, the safety evaluations were reviewed to determine if the changes involved an unreviewed safety question.

b. Observations and Findings

In general, the team found that the design changes associated with the reviewed modifications were technically sound and documented in accordance with Procedure DAP 21-22, "Plant Modifications," Revision 3. The safety evaluations (SEs) included sufficient bases to support the conclusions relative to determining if the change constituted an unreviewed safety question, with a noted exception discussed in Section E1.4, "Safety Evaluations."

The team identified one example where the licensee did not follow the modification procedure (high pressure coolant injection (HPCI) valve bushing locking device discussed in Section E1.3) and one example where the design change package (DCP) did not incorporate complete and adequate references (modification to allow the Containment Cooling Service Water (CCSW) to supply cooling water to the Emergency Core Cooling System (ECCS) room coolers).

The team identified that DCP M12-3- 97-007, “Modification to Allow the CCSW Cooling to Supply Cooling Water to the ECCS Room Coolers,” did not provide specific references to the hydraulic calculation and the Environmental Qualifications (EQ) calculation. The modification package stated “...an analysis of the design basis hydraulic calculation for the CCSW system has determined that the CCSW system has enough margin to provide cooling water flow,” but the modification did not reference a calculation number or a title. An appropriate reference to the hydraulic calculation should have been provided.

DCP M12-3-97-007 also stated, “Therefore, if safety-related cooling water can once again be supplied to the HPCI room cooler, assurance can be given that the temperature in the HPCI room will stay below 120°F during operation of the HPCI system and the HPCI room can remain a mild environment.” Through interviews and document reviews, the team determined that the HPCI room temperature actually exceeds 120°F (increases to maximum of 127°F, and drops to 121°F and then slowly increases). Neither the modification nor the SE mentioned that an EQ calculation was completed to show that these temperatures were acceptable.

c. Conclusions

The team concluded that with noted exceptions, the design control process was properly implemented and the design changes and safety evaluations were technically sound and documented in accordance with station procedures.

E1.2 Temporary Modifications

a. Inspection Scope (37001; 37700)

The team reviewed the licensee’s process for controlling temporary modifications (TMods). These controls were summarized in station Procedure No. NSWP-A-21, “Temporary Modifications,” Revision 0.

b. Observations and Findings

As of January 25, 2000, the licensee had 26 TMods installed. These TMods were minor or installed on nonsafety-related equipment. Most were scheduled for removal during the next applicable refueling outage.

The team reviewed selected TMods and verified that they were controlled as required by the procedure. Specifically, that the TMod review checklist (Exhibit A to the procedure) was appropriately filled out and the required supporting documentation (such as 10 CFR 50.59 evaluations) was included. Additionally, system engineers were performing quarterly walkdowns of these TMods, as required.

In July and December 1999, the licensee performed self-assessments of the TMod process. These assessments identified a generic concern with not following procedural requirements. Examples included TMods missing documentation or being potentially unauthorized. These findings were consistent with those documented in station PIFs since 1998. However, the team found a problem that had not been identified by the

licensee. Specifically, Step 6.8.1.1 of the TMod procedure required that the TMod coordinator perform and document monthly reviews of the TMod database. The team was informed that since April 1999, these reviews have apparently been performed, but not documented.

The licensee completed a root cause evaluation of the TMod process on January 25, 2000. This evaluation concluded that an overall poor procedure and a failure by some staff (primarily system engineers) to implement the program were the primary deficiencies. The team reviewed this evaluation and the proposed corrective actions (i.e., supplementary training, procedure revision, etc) and found them acceptable.

c. Conclusions

In general, temporary modifications were being appropriately controlled. Licensee self-assessments had identified several process deficiencies that were being addressed. One example where a process deficiency was not identified by the program self-assessment was identified by the team.

E1.3 Unit 2 High Pressure Coolant Injection Turbine Stop Valve Modification Performed Outside the Modification Process

a. Inspection Scope (37001; 37700)

The team reviewed the licensee's installation of a secondary retaining ring to the Unit 2 HPCI turbine stop valve (Valve No. 2-2303-STPV). The HPCI turbine and associated components were considered safety related equipment. This work occurred on January 21, 2000. The inspection consisted of a review of documents and interviews with licensee personnel.

b. Observations and Findings

The installation occurred following an observed steam leak originating from the stop valve. This leak resulted from a failure of the bushing assembly located inside the valve. The assembly consisted of two bushings adjacent and longitudinal to the valve shaft, located within a stainless steel stuffing box, and secured by a metal pin and peening of the box. Under normal operation, the bushings routed steam to the gland seal condenser. However, the securing pin had sheared, causing bushing misalignment and creating a steam path along the valve stem. The licensee replaced the bushing assembly and securing pin, repeened the box, and installed a secondary retaining ring to prevent recurrence. This work was performed under Engineering Request No. 9904064.

Although the retaining ring was not part of the original valve design, licensee management considered the work a repair and not a modification. Therefore, the work was not controlled per station procedure DAP 21-22, Revision 3, "Plant Modifications." However, the licensee could not provide a documented definition of what constituted a repair, including the associated controls. The team was informed that engineering management had specified informal controls for this work using DAP 21-22 as a reference. Specifically, prior to the installation the licensee consulted with the vendor before installing the ring, performed a 10 CFR 50.59 screening, and instituted a design

change request (DCR No. 990425) to revise the vendor drawings. However, these controls were implemented on an informal basis and there was no evidence that the other evaluations recommended by DAP 21-22 were considered.

Section C(8) of DAP 21-22, defined a design change as “a change that alters the design or technical requirements of any structure, system or component. The change can be a hardware change, which includes physical, setpoint or software, or a document change.” This definition further stated that a design change met at least one of three listed criteria. One of these criteria was that “the change in design requirements requires revising any design output documents including, but not limited to drawings, specifications and design analyses.” The installation of the retaining ring was a hardware change that required a revision to the vendor manual, a design output document, therefore it was a design change.

Section C(19) of DAP 21-22 defined a modification as “a permanent design change that does not meet the criteria for equivalent replacement and includes:

(1) Planned changes in plant design or operation that are accomplished in accordance with the requirements and limitations of applicable codes, standards, specifications, licenses and predetermined safety restrictions; and

(2) Changes to an item made necessary by, or resulting in, a change in design requirements.”

In addition, station procedure NEP-04-00, “Configuration Control Process Description,” Revision 4, Step 3.2(5) states that “changes adding new components where none previously existed” are not considered an equivalent replacement. Consequently, a modification was appropriate in this case.

This ring was intended to be a permanent addition and was installed in accordance with applicable codes and standards. It was not part of the original design and was considered a necessary change to prevent further bushing failures. Therefore, this ring met the definition of a modification. Steps E8 and E10 of DAP 21-22 required that all modifications be documented and evaluated using Appendices A and B to this procedure. These appendices were titled “Design Change Approval and Close-Out” and “Checklist of Engineering Activities and Other Requirements for a Design Change,” respectively. However, as stated above, this work was not controlled as a modification and, therefore, these appendices were not completed.

The licensee’s decision to define this modification as a repair and not follow DAP 21-22, could establish a precedent to bypass the design change process for similar work. Specifically, the lack of an explicit definition over what constituted a repair and associated controls may result in more significant design changes occurring without having performed the appropriate design reviews and approvals. In a subsequent Memorandum, dated February 9, 2000, the licensee’s Corporate Vice President, Nuclear Engineering, restated that the installation of the retaining ring was a repair and not a modification. However, this memorandum did not define a repair or the associated controls. On March 31, 2000, the licensee initiated PIF No. D2000-01922, to determine

if the installation of the retaining ring should have been controlled as a modification per DAP 21-22.

The team considered the failure to control the installation of the retaining ring as a modification in accordance with DAP 21-22, as a 10 CFR 50, Appendix B, Criterion V, violation. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1.a of the NRC Enforcement Policy (NCV 50-237/2000003-01(DRS); 50-249/2000003-01(DRS)).

c. Conclusions

The team concluded that licensee management bypassed the design change process during implementation of a modification to the Unit 2 HPCI turbine stop valve. This issue is considered an NCV.

E1.4 10 CFR 50.59 Safety Evaluations and Screenings

a. Inspection Scope (37001)

The team reviewed Procedure NSP-CC-3005, "10 CFR 50.59 Safety Evaluation Process," Revision 0, fourteen completed SEs, and six screenings.

b. Observations and Findings

(1) Background on Reactor Protection System (RPS) On-Line Testing

In response to Action Item 4.5.3 of Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem anticipated transient without scram (ATWS) Events," the BWR Owner's Group performed a study to evaluate the adequacy of the existing intervals for on-line functional testing. The study results were issued in General Electric (GE) Topical Report NEDC 30844, "BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3," dated January 31, 1985. Section 2 of the report stated that scram contactors are currently tested every 7 days, as part of the APRM testing, and every 31 days as part of other surveillance testing. Section 4.4.4 of this report stated that during the required trip sensor channel tests, each scram contactor which actuated the scram pilot solenoid valve is tested.

GE also performed another study to evaluate the feasibility of extending the surveillance frequency of RPS on-line functional testing. The results of this study were published in GE Topical Report NEDC 30851P, "Technical Specification Improvement Analyses for BWR Reactor Protection System," dated May 31, 1985. Section 5.7.1 of this report stated that scram contactors are currently tested at least once every seven days as part of the APRM sensor channel functional test. Both GE topical reports discussed the scram contactors being the weak-link in the RPS, and current weekly testing during APRM channel functional testing as optimal.

On July 15, 1987, the NRC issued an SER to the BWR Owners Group which stated that GE Topical Report NEDC-30844 provided an acceptable basis for resolving Item 4.5.3 (on-line functional testing of the RPS) of Generic Letter 83-28. In addition, the SER stated that GE Topical Report NEDC-30851P provided an acceptable generic basis for supporting technical specification (TS) changes related to the RPS testing. Section 5.4 of the SER stated that the scram contactors are de-energized whenever an individual sensor and its associated relay are tested.

By letter dated July 20, 1990, from Commonwealth Edison Company (ComEd) to the NRC, Dresden Station indicated their endorsement of the BWR Owner's Group Reports NEDC 30844 and NEDC 30851P as being applicable to Dresden. On August 6, 1990, the NRC issued a SER to the licensee in response to the licensee's endorsement of the GE Topical Reports. Section 3 of the SER stated that the existing intervals, as recommended in the Topical Reports for on-line functional testing are consistent with achieving high RPS availability at all operating reactors.

Prior to 1998, the licensee performed channel functional surveillance tests in accordance with Technical Specification 4.1.A.1 Table 4.1.A-1. These tests included cycling of the scram contactors and the scram pilot valves during the weekly APRM channel functional tests. In 1997 and 1998, the licensee experienced three reactor scrams while performing RPS on-line channel functional tests. Therefore, in an effort to reduce the number of scrams received while in testing, the licensee developed a test method to reduce the number of half-scrams during surveillance testing by allowing channel functional testing without cycling the scram contactors. The scram contactors were tested every 18 months as a part of the logic system functional test. The team discussed the concern with NRR and determined that the licensee conformed to TS requirements for APRM channel functional and logic system functional testing.

(2) <u>Inadequate 10 CFR 50.59 Screening and Safety Evaluation</u>

In 1998, the licensee performed a series of safety evaluations to change the testing methodology for RPS on-line channel functional testing. To prevent time spent in half-scram conditions during RPS channel functional testing, the licensee would install a test box (jumper) around the sensor relay contacts. When a signal exceeding the scram set points was injected to the sensor, the relay would change state and the logic contacts would open. However, the scram contactors (K-108 relays) which are in series with the sensor relay contacts, would not de-energize to produce a half-scram due to the installation of the test box. Therefore, the scram contactors were normally not tested as part of the RPS channel functional tests except in the case of the monthly main steam isolation valves closure test. The team noted that since 1998, the scram contactors were not being tested weekly in accordance with the licensee's commitments.

The team reviewed the 10 CFR 50.59 screening for changes to DOS 500-03, "APRM Rod Block and SCRAM Functional Test." The purpose of the change

was to add steps which jumpered the RPS trip function so that the scram contactors would not be tested (de-energized) as part of the APRM sensor channel functional test. The team determined that the 10 CFR 50.59 screening failed to consider the two applicable SERs in which the licensee committed to perform weekly testing of the scram contactors. This oversight resulted in:

- The failure to perform a safety evaluation as required by Procedure NSWP-A-04;

- Changes in licensee commitment for RPS on-line functional testing without notifying the Commission; and

- Reduction in testing periodicity of the scram contactors without adequate evaluations.

The team also reviewed SE No. 1998-02-178 which revised channel functional testing for electro-hydraulic control system low oil pressure and turbine control valve fast closure scram switches to prevent unnecessary time spent in half-scram condition. Surveillance procedures DIS 0500-08 and DOS 0500-09 were revised in July 1998 to allow installation of a test box. This configuration prevented the logic contacts from the associated sensors from opening and prevented de-energization of the scram contactors during the monthly sensor channel functional testing. Section 2.a of the SE required listing of the SAR sections reviewed, including any other controlling documents such as SERs. However, the safety evaluation failed to list or consider the applicable SERs noted above.

After this deficiency was identified to the licensee, PIF No. D2000-00800 was initiated on February 9, 2000. The licensee initiated the following actions:

- A Nuclear Operations Notification (NON) was issued to inform other ComEd stations on February 11, 2000;

- LaSalle and Quad Cities were informed of this testing deficiency as both stations had adopted the same testing methodology as Dresden; and

- The requirement to perform weekly testing of the scram contactors was adopted as of February 11, 2000.

Based on GE Topical Report NEDC 30851P, the improved technical specification (ITS) will extend the individual sensor channel test intervals to quarterly while keeping the scram contactor test interval fixed at seven days. The licensee indicated that an application for the ITS at Dresden was submitted for NRC review.

The team informed the licensee that failure to maintain weekly testing of the scram contactors as delineated in the above GE topical reports was a deviation to a licensee commitment to the NRC in response to GL 83-28.

In addition, Technical Specification 6.8, “Procedures and Programs,” required, in part, that written procedures shall be established, implemented, and maintained covering activities as recommended in Appendix A of Regulatory Guide 1.33. Appendix A of Regulatory Guide 1.33 stated, in part, that typical safety-related activities should be covered by written procedures. Specifically, administrative procedures are needed for procedure review and approval. Part of the purpose of NSWP-A-04, “10 CFR 50.59 Safety Evaluation Process,” Revision 1-1, was to document whether a Safety Evaluation is required for a proposed procedure change. The procedure required, in part, performing a safety evaluation when the proposed procedure change results in a change to safety analysis report (SAR) commitments. Contrary to the above, in June 1998, the licensee failed to perform a safety evaluation when the proposed change to DOS 500-03 changed the licensee’s commitment to perform scram contactor testing from weekly to monthly. The failure to perform a safety evaluation for the change in testing periodicity of the scram contactors is considered a violation of Technical Specification 6.8. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee’s corrective action program as PIF D2000-00800. (NCV 50-237/2000003-02(DRS); 50-249/2000003-02(DRS)).

c. Conclusions

The team determined that inadequate review of the applicable SERs while performing the 10 CFR 50.59 screening to change the testing methodology for the APRM channel functional test resulted in a failure to perform a safety evaluation. This oversight contributed to a reduction in the surveillance periodicity for the RPS scram contactors without prior notification to the NRC of the change in licensee commitment and without adequate technical evaluation. This was considered a violation of Technical Specification 6.8. The issue is considered an NCV.

E1.5 Calculations

a. Inspection Scope (37550)

The team reviewed selected mechanical and electrical calculations associated with modifications. The calculations were reviewed for completeness, and to verify that the appropriate design inputs, assumptions, and methods were used, and that system tests correctly reflected calculation conclusions.

b. Observations and Findings

The team reviewed several calculations, both mechanical and electrical, and found the calculations to be technically sound and performed in accordance with procedures. In addition, the team reviewed the corrective action plans and implementation of corrective actions for design calculation deficiencies. The team found that final corrective actions were appropriate and appeared effective when implemented. The effectiveness review, based on the initial implementation of corrective actions, was critical and had a positive

impact on the final implemented corrective action and the overall quality of design calculations.

During the inspection, the licensee was initially unable to locate Calculation BSA-D-97-01, Revision 1, “Calculation of LPCI Corner Room Temperature for a Loss of Room Cooler Event,” within the Electronic Work Control System (EWCS). The licensee determined that the calculation title had a typographical error, which made it difficult to locate within the electronic system. The extent of condition revealed seven additional calculation titles that had typographical errors which could have hindered locating the documents within EWCS.

The team also reviewed Calculation No. DRE 96-0189, “Voltages on Loads Fed From the Safety-Related 250 V Batteries,” Revision 1. This calculation was performed to ensure that minimal operating voltages were available for various HPCI equipment operation. The conclusion stated that the HPCI turbine gland steam condenser exhauster and its hotwell drain pump motors would experience less than 90 percent of their rated voltage during one or more periods. Therefore, successful operation of the equipment could not be assured. The calculation also stated that the subject equipment was classified as nonsafety-related and it would not be required for HPCI operation. The conclusion further stated that if these motors were upgraded to safety-related status in the future, additional investigation would be required to demonstrate successful operation at the available voltage.

In April 1998 and June 1997, the Units 2 and 3 HPCI gland seal leak off (GSLO) systems were upgraded to safety-related status, respectively. Continuous operation of the GSLO system was required to support HPCI operation due to room temperature concerns. However, the team determined that the subject calculation was not revised to reexamine the acceptability of the available voltage for the exhauster and hotwell drain pump. When the team identified this concern to the licensee, PIF D2000-00801 was initiated to address this discrepancy. The licensee’s initial review determined that the HPCI system remained operable.

The licensee stated that an extensive review of the calculation would be performed. This item is considered unresolved pending licensee review and re-analysis of available voltages and NRC review of the results (URI 50-237/2000003-03(DRS); 50-249/2000003-03(DRS)).

c. Conclusions

The design calculation process was properly implemented and the calculations reviewed were generally technically sound. However, the team identified that the licensee failed to re-analyze the operation of the HPCI gland seal leak off (GSLO) system for the minimum required operating voltages when the GSLO system components were upgraded to safety-related status in 1997 and 1998 for Units 3 and 2, respectively. This was considered an Unresolved Item pending licensee re-analysis of available voltages.

E2 Engineering Support of Facilities and Equipment

The team reviewed the effectiveness of engineering support to plant organizations, which included plant management, operations, and maintenance. Much of the engineering support involved assistance in the documentation, evaluation, and resolution of problems.

E2.1 Design Basis of LPCI Room Coolers

a. Inspection Scope

The team conducted walkdowns, interviews and document reviews to determine the design basis for the LPCI Room Coolers.

b. Observations and Findings

The team identified conflicting information and requirements relative to the LPCI room coolers. During the walkdown of the LPCI system, the system engineer indicated that the 2A LPCI room cooler was out-of-service and was not needed until 12 days after a postulated LOCA. The basis for the 12-day post-LOCA requirement was a 1993 environmental qualification (EQ) calculation that included the restoration of the LPCI room cooler within 12 days as a design assumption. The team determined that this criterion was not translated into station operating or emergency procedures, was not incorporated into operator training, and was in conflict with statements in UFSAR sections, which stated that the loss of LPCI room coolers did not affect the operability of the LPCI and core spray (CS) systems. Subsequently, the licensee documented these issues in PIF D2000-00700 as follows:

- No site procedure existed to restore LPCI room cooler operation within 12 days.
- If the room coolers were not returned to service and the temperature remains at 178°F, Measurement Analysis and Control (GE/MAC), Rosemount Transmitters, and GE LPCI motors were not qualified to one year. (The team determined that IEEE 323-1974 indicated a requirement of 100 days post-Design Basis Accident (DBA) for BWRs; however, the licensee could not provide a basis for the one year post-LOCA requirement).
- The calculation results appeared to be in conflict with UFSAR Sections 3.11.4 and 9.2.2.4. (These sections stated that operation without the room coolers did not compromise the operability of the LPCI system.)
- The temperature profile assumed in the EQ calculation was updated in 1997, but the EQ calculation was not.

Based on plant conditions during the inspection, the 2A LPCI room cooler being out of service, and calculations of record, the licensee declared the A LPCI train operable but degraded and initiated a formal operability determination.

During the Design Basis Initiative (DBI) conducted in response to NRC 10 CFR 50.54(f), "Letter on Design Bases Information," the licensee identified discrepancies among UFSAR sections and calculations regarding LPCI room temperatures. Specifically, PIF D1998-03208 documentation that "EQ Binder 25D, Tab C, Section 6.2 provides the post accident (LOCA) Environment Conditions with a temperature of 178.6°F (12 days). The EQ limit of 185°F is not mentioned. The same source stated that the room cooler will be restored after 12 days, and room temperature should return to 150°F after 12 days." The resolution of this PIF was an opportunity to identify that the 12-day LPCI room cooler restoration criterion had not been properly incorporated into station procedures and the UFSAR. The PIF resolution did not address the 12-day restoration criterion. The team concluded that the licensee failed to properly translate the design basis into procedures and the UFSAR.

The team considered the failure to properly translate design information, the 12-day LPCI restoration criterion, into station procedures and the UFSAR as a 10 CFR 50, Appendix B, Criterion III, violation. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation has been entered into the licensee's corrective action program as PIF D2000-00700 (50-237/2000003-04(DRS); 50-249/2000003-04(DRS)).

c. Conclusions

The team considered the failure to properly translate design information regarding the 12-day LPCI restoration criterion into station procedures and the UFSAR as a violation of 10 CFR 50, Appendix B, Criterion III. This issue is considered an NCV.

E3 Engineering Procedures and Documentation

E3.1 Modification/Procedure Review

a. Inspection Scope (37550)

The team reviewed a recent modification to the station blackout (SBO) diesel generator digital control system (DCS). The team focused on the procedures used for this modification.

b. Observations and Findings

During a non-safety related modification to upgrade the SBO diesel generator DCS for Y2K compliance, the licensee did not exercise appropriate software control. The vendor based the software revision on a version of the software different from the version installed in the DCS.

NSP-CC-3021, "Control of Computer Software and Services," Revision 0, dated October 20, 1998, was the procedure used by the licensee to control all software installed in the plant. This procedure provided for five levels of classification of software installed or used in the plant. The classification levels were described in Table C.1.1 and the classification flowchart was illustrated in Figure C.1.1. Software owners were

required to fill out Attachment A, “Computer Program Classification Checklist.” The team identified inconsistencies between the checklist and procedure.

The SBO DCS met the requirements in Table C.1.1 of NSP-CC-3021 for level C software. The system engineer used the Computer Program Classification Checklist which led him to erroneously classify the software at level E. Level E software required no programmatic control. Had the software been properly classified at level C, a verification and validation plan would have been written to ensure proper configuration control during the modification. An apparent cause evaluation performed by the licensee determined that the system engineer did not follow the procedure and misclassified the software. This appeared to be accurate, however, inconsistencies between the checklist and procedure contributed to the problem.

c. Conclusions

During a review of an SBO modification, the team determined that the licensee did not exercise appropriate software control. The team identified inconsistencies between the checklist and procedure used to control computer software. In response to the team’s observations, the licensee initiated PIF D2000-00731.

E5 Engineering Training and Qualification

E5.1 Review of Engineering Training

a. Inspection Scope (37550)

The team evaluated the licensee’s training program for engineers. This evaluation included a review of training program procedures, training materials, training records of several engineers, and observation of a class in progress. Discussions were held with cognizant licensee personnel about the training program.

b. Observations and Findings

The licensee recently implemented a new training program complying with a National Academy of Nuclear Training document, ACAD 98-004, “Guidelines for Training and Qualification of Engineering Personnel,” dated May 1998. The program established requirements for initial training, position specific certification training, and continuation training. Training progress for each engineer was well documented and centrally controlled. The training staff appeared dedicated to implementing the program.

Continuation training, of two days duration, had taken place quarterly. Engineers have been required to pass an examination covering the material, and the results have been documented in their training record.

Course material reviewed was detailed. System Engineering course curriculum has been reviewed monthly by a Curriculum Review Committee chaired by the Assistant System Engineering Manager. The modification process included a step for evaluation of any necessary changes to the training materials. However, the team identified that

the LPCI system design requirement discussed in Section E2.1 was not translated into the operator training program.

c. Conclusions

The training program for engineers appeared to be adequate, however, the team noted that a LPCI system design requirement was not translated into the operator training program.

E5.2 Use of Probabilistic Risk Assessment in Engineering Design Reviews

a. Inspection Scope (37550; 37700)

The team reviewed the application of Probabilistic Risk Assessment (PRA) insights during engineering department design reviews. Specifically, the team determined if engineers were familiar with the station specific Probabilistic Safety Assessment (PSA) and whether the use of PRA insights were addressed in station procedures.

b. Observations and Findings

The team reviewed several modification packages to determine whether design engineers were considering PRA insights. Specifically, the team verified that engineers were using the guidance in DAP 21-22, Revision 3, “Plant Modifications,” (Attachment D), which required that the station PRA coordinator be contacted if a proposed design change may significantly affect the PSA.

The engineers had received training on PRA insights, most recently in June 1999. During this training, the engineers were familiarized with the criteria to be used when initially screening modifications for impact on the PSA model. This criteria was summarized in Exhibit B of Procedure No. NEP-17-04, Revision 4, “Nuclear Engineering PSA Model Update.” The team reviewed these criteria and concluded that it reasonably addressed PRA concerns. The team also reviewed the lesson plan for a more in-depth training on PRA that the station conducted in July 1998. This training adequately covered PRA fundamentals in addition to the PSA. Additional classroom training was planned for the first quarter of 2000.

The corporate PRA coordinator performed quarterly assessments of the station PRA process to verify that PRA concerns were being reviewed. These assessments varied from a selective review of modification packages to interviews with staff. According to the corporate coordinator, these assessments have not identified any significant problems.

c. Conclusions

Station design engineers had received training in Probabilistic Risk Assessment, including the station specific Probabilistic Safety Assessment. The team noted that risk insights were included in station procedures and were being considered by engineers during planned modifications.

E7 Quality Assurance in Engineering Activities

E7.1 Corrective Action Program

a. Inspection Scope (40500)

The team reviewed the implementation of the corrective action program at Dresden Station. The review included the mechanisms available for identification, investigation, and corrective action related to deficient conditions. In addition, the team reviewed selected PIFs generated by licensee personnel and verified whether adequate corrective actions were taken to address the problems identified. The team interviewed engineering and operations personnel, representatives of the nuclear oversight group, and station management.

b. Observations and Findings

(1) The team reviewed NSP-AP-4004, "Corrective Action Program Procedure," Revision 4, for the identification of conditions adverse to quality. Per this procedure, the deficient condition was noted on a PIF, routed to the individual's supervisor, and then to the control room for an operability determination. The PIF was then reviewed by station management and Action Requests (ARs) were assigned for resolution; after the ARs were assigned, the PIF was closed. Each AR was then closed to one of several other documents: an apparent cause evaluation (ACE) for root cause analysis; an engineering request (ER) for determination of corrective action; or a work request (WR) for actual maintenance to repair the discrepancy. The team noted that the programs were not interconnected within the ComEd computer system; as such, the corrective action program was disjointed: PIFs and ARs were used for identification of deficiencies, then the PIF or AR could be closed to an ACE or an AR which could be closed to a WR or ER. The team determined that tracking corrective actions was inconsistent because the licensee was using multiple data bases for maintaining records.

The team identified examples where conditions adverse to quality were entered into one of the tracking systems but later canceled resulting in untimely corrective action. In June 1997, AR970051643 was initiated to repair the transmitter for the total flow recorder for the Division 2 LPCI system. (Also see NRC Report 50-237/99023(DRP), Section O4.1). The AR was closed to an engineering request (ER 9703281), which was closed one week later with no action taken. The associated work request (WR970068571) was canceled by the system engineer stating that reading was "OK." In April 1998, another ER was written noting that the original ER was erroneously closed and that the transmitter still needed replacement. As of the end of the inspection, the transmitter was still inoperable. The team was informed that a modification has been initiated to replace the existing LPCI total flow recorders and upgrade them to safety-related status.

(2) The team performed a detailed review of selected PIFs. The PIFs contained a good description of the problem, were correctly prioritized, and most corrective actions were appropriate for the significance of the problems. Approximately 25

to 50 PIFs were reviewed by the licensee during daily event screening committee meetings. For those PIFs reviewed, the most significant PIFs had root cause determinations and effectiveness reviews performed. A recent example of effective corrective actions was the licensee's action to prevent a recurrence of welding problems. However, there were instances where deficiencies were known by the engineering staff but not identified or entered into one of the systems for correction. In addition, there were examples where conditions adverse to quality were entered into one of the systems but later canceled resulting in untimely corrective action.

The team noted that PIFs were not always issued for known conditions adverse to quality. For example, the team identified that PIFs were not issued for three unsatisfactory diesel oil samples for the Unit 1 Diesel Fire Pump. On July 25, 1999, November 11, 1999, and December 20, 1999, the fuel oil for the Unit 1 diesel fire pump was found to be contaminated. The fire protection system engineer was aware of this but did not initiate a PIF. As a result, no corrective actions were taken to prevent recurrence for diesel fuel samples that did not meet the testing criteria.

(3) The team also identified one other example where a recognized deficiency was not entered into the corrective action system. Specifically, during a plant walkdown on February 7, 2000, the team observed that the radwaste solidification building did not meet its required differential pressure of -0.125 inches relative to building external pressure. This value was stated in section F(1) of station procedure DOP 5750-20, Revision 1, "Radwaste Solidification Building Ventilation System." According to the system engineer, this has been a recurring problem since 1992, due in part to a failure to control the solidification building access door. This door is one of three and specifically serves as the boundary between the radwaste solidification and max recycle buildings. While DOP 5750-20 specifies controls over the two doors in the solidification building, it does not address this access door. Neither the solidification or max recycle buildings were considered safety related and both were low contamination areas. Subsequent to the team's review, the licensee documented this issue in PIF No. D2000-00736.

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to promptly identify and take appropriate corrective actions to correct the conditions adverse to quality noted in item b.(2) above. Item b.(2) is considered a violation of 10 CFR 50, Appendix B, Criterion XVI. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The licensee entered this issue in the corrective action program as PIF 2000-00810. (NCV 50-237/2000003-05(DRS); 50-249/2000003-05(DRS)).

c. Conclusions

The team concluded that the Dresden corrective action program was generally effective. However, the team identified some examples where the program did not function as

required. Deficiencies were known by the Dresden engineering staff but were not entered into the corrective action program, and repairs to conditions adverse to quality were canceled by staff personnel after they had been entered into the system. The example noted above in Item b.(2) is considered a violation of 10 CFR 50, Appendix B, Criterion XVI. This issue is considered an NCV.

E7.2 Review Committee Activities

a. Inspection Scope (40500)

The team reviewed the records for the Plant Onsite Review Committee (PORC) and Nuclear Safety Review Board (NSRB). The review included evaluating committee minutes and a review of corrective actions taken for problems identified by the safety committees. The activities of these committees were discussed with cognizant licensee personnel.

b. Observations and Findings

The PORC was a multi-disciplined committee responsible for providing an oversight review of documents required for safe operation of the plant. The meetings observed by the team were conducted in a professional manner and the participants were well prepared, based on their participation in the technical discussions.

The NSRB provided an independent review and oversight function separate from the daily operation of the plant. NSRB used subcommittees to screen issues to determine which items should be actually reviewed by the NSRB. During a review of the NSRBs board meeting minutes and interviews with cognizant licensee personnel, the team determined that the NSRB was actively and effectively performing their assigned responsibilities.

c. Conclusions

The team concluded that the onsite and offsite review committees were effective in performing their assigned reviews, investigations and evaluations.

E7.5 Root Cause Analysis and Trending

a. Inspection Scope (40500)

The team assessed the program for trending plant problems and reviewed selected trend reports. In addition, the team reviewed the root cause program and selected root cause reports. Effectiveness reviews were also evaluated.

b. Observations and Findings

The trend coordinator coded and tracked PIFs by the root or apparent causes using the PIF historical database. This data could be searched and sorted by codes and key words to identify trends. Upon identification of an adverse trend, an adverse trend PIF

was issued to identify if additional corrective actions were necessary. The team reviewed several trend reports and determined that the reports were of good quality. This was due, in part, to having a trend coordinator who was knowledgeable about the plant. However, the team identified that some engineers did not trend equipment problems. This included a failure to trend equipment out-of-tolerances. The team was not given the data requested for this item until the end of the inspection. Consequently, the resident inspectors were informed of this issue for followup.

The licensee performed root cause determinations for the most significant problems. Approximately 50 root cause determinations were performed each year. The team reviewed selected root cause determinations and concluded that they were comprehensive, and the associated corrective actions helped prevent problem recurrence.

The licensee was performing effectiveness reviews and had identified instances where corrective actions were ineffective. Additional corrective actions were assigned to these problems.

c. Conclusions

Root cause investigations and effectiveness reviews were performed for significant problems. The team identified a concern with system engineering's lack of trending of equipment problems.

E7.6 Engineering Department Self-Assessments

a. Inspection Scope (40500)

The team reviewed the Engineering Department self-assessment program implemented under AD-AA-103, "DGG Self-Assessment Procedure." The program evaluation consisted of reviews of self-assessment reports completed within the past two years, recent performance indicators, and corrective actions for select issues identified in the assessments.

b. Observations and Findings

Engineering Department Self-Assessment Program

The self-assessment process was described in AD-AA-103, NGG Self-Assessment Procedure, Revision 1 and included focus area self-assessments, One-on-One management observations, monthly assessments reports (summarized assessments and management observations), and quarterly assessment reports (summarized the monthly reports). The department quarterly reports were reviewed and challenged by department self-assessment coordinators at the Station Trending Analysis Function (STAF). The station self-assessment coordinator compiled the department quarterly self-assessments for presentation to the Trending Review Function (TRF). The TRF, consisting of senior station managers who reviewed the station self-assessment report, challenged the departmental assessment conclusions, and approved the report.

The team reviewed engineering One-On-One management observations completed during the period of December 12, 1999, to January 15, 2000, eight focus area self-assessments, and the Quarterly Engineering Assessment Report for the 4th Quarter 1999. The team also attended the TRF meeting on February 8, 1999. The team concluded the required number of self-assessments was completed and met the intent of AD-AA-103. The assessments were narrow in scope and focused on specific areas of the programs being reviewed (i.e., valve categorization within the AOV program).

Engineering Staff and Supervisor Perception of the Self-Assessment Process

The team interviewed approximately 20 design and system engineering personnel, including staff, leads, and managers. There was a general engineering staff perception that the self-assessment process did not have full management support. The majority of the staff interviewed had not personally participated on a self-assessment team. Those that had participated stated that prior to their personal experience, self-assessments were considered required but not very useful. After personal experience by both staff and managers, views changed to see the benefits of performing quality, critical self-assessments.

c. Conclusions

The team determined that the assessments were narrow in scope and focused on specific areas of the programs being reviewed (i.e., valve categorization within the Air-Operated Valve program). Based on interviews, the team noted a general engineering staff perception that the self-assessment process did not have full management support.

E8 Miscellaneous Engineering Issues

E8.1 Inspector Followup Item 50-237/94014-08(DRP); 50-249/94014-08(DRP): Licensee's resolution of the radwaste, max recycle and high range sample system (HRSS) building ventilation concerns. In October 1994, the licensee identified several long standing problems with unsealed pressure boundaries, excessive flow resistance (such as blocked ducts) and improper air distribution that adversely affected the ventilation systems. Most of these problems consisted of material defects needing repair. However, the overall concern required flow balancing of the individual systems to identify whether the associated equipment was functional.

During system walkdowns, the team observed that most of the material defects were corrected. For example, the team observed that the HRSS sample panels and radwaste control room door seals were generally well maintained. Additionally an approved plan was developed for performing flow balancing on the HRSS building and a draft plan was being developed for the reactor building. Both of these plans had associated action requests for work scheduling.

However, the team observed that the radwaste and max recycle building problems were not being effectively addressed. The respective system engineers were aware of the

deficiencies and had prioritized corrective actions, but had difficulty obtaining management support to schedule and address their concerns. This led to some long standing problems being handled at the engineers' level rather than through the corrective action process. One specific example identified by the team, regarding the control of the radwaste solidification building access door, is discussed in Section E7.1.

Licensee management acknowledged the radwaste ventilation system problems and, in particular, the failure to document these problems in the corrective actions process. These issues were being addressed under Problem Identification Form D2000-00736. Because this issue was being addressed through the licensee's corrective actions process, this item is considered closed.

E8.2 Use of Industry Operating Experience

a. Inspection Scope (40500)

The team reviewed the licensee's process for receiving and reviewing industry operating experience (OPEX) reports. This process was described in CWPI-NSP-AP-1-10, Revision 0, "Operating Experience." The inspection consisted of a review of documents and interviews with personnel.

b. Observations and Findings

Industry OPEX reports were distributed to the station OPEX coordinator by the licensee's corporate group. The coordinator was responsible for assigning all applicable items to an appropriate individual for review and resolution. The team reviewed several selected OPEX reports and verified that, with one exception, they had been appropriately addressed.

The exception was Operating and Maintenance Report (O&MR) No. 425, which was reviewed by the station's Instrument Maintenance Department (IMD). This report described reactor scrams caused by inadvertent equipment actuations from air entrapped in instrument sensing lines or during operation of instrument system valves. The team determined that the IMD review focused primarily on internal department issues and not on overall station applicability. This resulted in a concurrent, applicable Licensee Event Report (LER No. 50-249/99001-00) not being included. This LER discussed an inadvertent reactor scram occurring, in part, from deficiencies in an operations department procedure used during work on various reactor pressure instruments. Although these deficiencies were similar to those discussed in the O&MR, they were not included in the IMD review.

Several similar examples were identified in the preliminary results of a OPEX self-assessment conducted in December 1999. This indicated a potential, generic concern with whether the assigned reviewers considered general station applicability when evaluating industry events. This concern was documented in licensee PIF No. D2000-00501.

c. Conclusions

The team determined that the licensee had access to industry operating experience reports and was adequately communicating them to station staff. However, these reports were not being reviewed for general station applicability in all cases. In one example, this resulted in the results of a station Licensee Event Report not being included during a concurrent review of an applicable industry report.

IV. Management Meetings

X1 Exit Meeting Summary

The team presented the inspection results to members of licensee management in an exit meeting on February 11, 2000, and during a subsequent meeting with the engineering manager and a telephone re-exit on March 23, 2000. The licensee acknowledged the findings presented. The team asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Ambler, Regulatory Assurance Manager
S. Barrett, System Engineering Manager
P. Chabot, Site Engineering Manager
C. delaHoz, Reactor Engineering Supervisor
R. Fisher, Station Manager
B. Hanson, Shift Operations Superintendent
R. Kelly, Regulatory Assurance NRC Coordinator
L. Licata, Engineering Administration Supervisor
A. Lintakas, Assistant System Engineering Manager
W. Lipscomb, Training Manager
R. Peak, Design Engineering Manager
J. Stone, Nuclear Oversight Manager

NRC

D. Smith, Senior Resident Inspector
B. Dickson, Resident Inspector
D. Roth, Resident Inspector

INSPECTION PROCEDURES USED

IP 37001:	10 CFR 50.59 Safety Evaluation Program
IP 37550:	Engineering
IP 37700:	Design Changes and Modifications
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237/249 2000003-01	NCV	Failure to control an HPCI modification in accordance with Procedure DAP 21-22, “Plant Modifications,” Revision 3
50-237/249 2000003-02	NCV	Inadequate review of the applicable SERs while performing the 10 CFR 50.59 screening to change RPS contactor testing interval
50-237/249 2000003-03	URI	Failure to re-analyze the operation of the HPCI gland seal leak off (GSLO) system at below the minimum required operating voltages when the system was upgraded to safety-related status
50-237/249 2000003-04	NCV	Failure to properly translate design information, the 12-day LPCI restoration criterion, into station procedures and the UFSAR
50-237/249 2000003-05	NCV	Licensee failed to promptly identify and take appropriate corrective actions to correct some long standing conditions adverse to quality

Closed

50-237/249 94014-08(DRP)	Licensee’s resolution of the radwaste, max recycle and high range sample system (HRSS) building ventilation concerns.

Discussed

None

LIST OF ACRONYMS USED

AOV	Air-Operated Valve
AR	Action Request
BWR	Boiling Water Reactor
CCSW	Containment Cooling Service Water
ComEd	Commonwealth Edison Company
CFR	Code of Federal Regulations
CS	Core Spray
DAP	Dresden Administrative Procedure
DCS	Digital Control System
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EHC	Electro-Hydraulic Control
EQ	Environmental Qualification
ER	Engineering Request
EWCS	Electronic Work Control System
HPCI	High Pressure Coolant Injection
HRSS	High Range Sample System
IMD	Instrument Maintenance Dept.
LER	Licensee Event Report
LPCI	Low Pressure Coolant Injection
LORC	Loss of Room Cooler
NGG	Nuclear Generation Group
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
O&MR	Operating and Maintenance Report
OPEX	Operating Experience
PIF	Problem Identification Form
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
RIII	NRC Region III
SBO	Station Blackout Diesel Generator
SE	Safety Evaluation
TMod	Temporary Modification
TRF	Trending Review Function
WR	Work Request

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that the NRC team reviewed the documents in their entirety, but, rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Nor does inclusion in this list imply NRC acceptance of the document, unless specifically so stated in the body of the inspection report.

Assessments and Audits

Nuclear Oversight Assessments:

NOA-12-99-ES01:	VETIP [Vendor Equipment Technical Information Program] Assessment
NOA-12-99-ES02:	Modification and Temporary Alteration Assessment
NOA-12-99-ES03:	Seismic Qualification and Corrective Action Assessment
NOA-12-99-ES04:	Battery Charger and DC [Direct Current] Systems (125/250VDC)
NOA-12-99-ES06:	Design Control Assessment
NOA-12-99-ES07:	System Engineering Assessment
NOA-12-99-ES08:	Corrective Action Program
NOA-12-99-ES11:	Engineering Administration, Qualifications, and Quality Assurance Records

Self-Assessments:

Trending, March 1999
Operability Determination, June 1999
Maintenance Self-Assessment: Foreign Material Exclusion Program
Maintenance Rule Implementation, June 1999; Engineering Effectiveness, August 1998
Evaluation of Changes Made to D2R15 Modification After Start of Implementation, May 1998
Engineering Self-Assessment Report (ATI No. 15723)

Quality Assurance Audits:

ComEd-98-05:	Audit of All ComEd Engineering Organizations and Functions
QAS-12-98-19:	Dresden Engineering Assurance Group
QAS-12-98-31:	Self-Assessment

Calculations

DRE96-0189	Voltages on Loads Fed From the Safety-Related 250 V Batteries, (Revision 1)
DRE96-0224	Determination of Minimum Required Core Spray and Low Pressure Core Injection Lines Static Head for Keep Fill Function, Revision 0, November 1996
DRE96-0241	ECCS Suction Hydraulic Analysis without the Strainers, Revision 0, December 1996
DRE97-0002	Dresden LPCI/CS NPSH Temperature Limits, Revision 0, January 1997

DRE97-0161	Justification for Continued Operation of HPCI Gland Seal and Exhauster Subsystem Components
DRE97-0252	Sizing of CCSW Pipe and Flow Limiting Orifices for ECCS Room Coolers
DRE97-0276	Assessment of Leakage Current for Class 1E Instrumentation Circuits That are Terminated on GE and Marathon Terminal Blocks, Revision 0, December 31, 1997
DRE97-0277	Assessment of Leakage Current for Class 1E Control Circuits That Are Terminated on GE and Marathon Terminal Blocks, Revision 1, October 21, 1999
DRE98-0077	HPCI Room Thermal Response with Reduced Room Cooler Capability
VT 10	Unit 1 HPCI Building 125 Vdc Battery Room Ventilation to Dilute Hydrogen Concentration
7328-00-19-2	250 Vdc Battery Bus Voltage Drop
BSA-d-97-01	LPCI Room Thermal Response for a Loss of Room Cooler Event, Revision 1, October 14, 1997
EQC-DR-11	Evaluation to Assess the Impact of LOCA/LORC on the EQ Equipment Located in the ECCS Pump Rooms, Revision 0, March 23, 1993

Engineering Requests

ER9803041	Identify Fuses and Populate Data for Panel 3-2253-25, September 8, 1998
ER9803580	U3 125 VDC Battery Charger No. 3 Fuses Do Not Match Prints, October 27, 1998
ER9900139	Fuse Data Needs to Be Populated in EWCS, January 13, 1999
ER9900676	3B Recirc PMP Xducer/VMS Fuse Size Correction, February 14, 1999
ER9900801	Various Fuse Discrepancies Need Engineering Assistance, February 20, 1999
ER9901245	Evaluate Fuse 1FU in Local HPCI Sig Converter Panel-10 or 15, March 27, 1999
ER9902943	Fuses in 903-27 Panel Not Listed in EWCS (RPIS Indication), October 5, 1999
ER9903163	Labeling of Fuses in Panel 2203-27, October 18, 1999
ER9703671	Wrong Fuse Found in Panel 2253-11 3L1 Block, September 15, 1997
ER9900066	Panel 2/3-944-5 CKT 5 Fuse Doesn't Match Print Data, January 7, 1999
ER9900563	U3 RFP Vent Control Panel 2253-25 Fuses, February 9, 1999
ER9901532	Wrong Fuse Found Installed in U2 SBO Battery Supply Fan CKT, April 28, 1999
ER9902070	Please Verify Fuse Listed Is Correct Type for Application, June 23, 1999
ER9904064	Six Foot Steam Plume with High Pressure Core Injection System Operating, January 21, 2000

Modifications

DCP-9500051:	Various Unit 2 Control Room Panel Enhancements
DCP-9500071:	Unit 2 24/48VDC Battery & Battery Charger Replacement Re-Power Analog Trip System Panel 2202-73a
DCP-9700244	Design Change Package Feedwater Control System M12-2-97-006, July 27, 1998

DCP-9700246	ECCS Room Cooler Cooling Water Supply Modification
DCP-9800172	Design Change Package for Unit 3 Feedwater Control System Upgrade, July 28, 1998
DCP-9800220	Install Unit 2 Tie-In to 345KV Switchboard Battery and Bus
DCP-9800238	Bus 28 and 29 UV Reset Pushbuttons
DCP-9800289	Unit 2 Modify Reactor Recirculation Pump Motor Generator
DCP-9800300	Unit 3 Modify Reactor Recirculation Pump Motor Generator
DCP-9800311	Install and AGASTAT Relay to Function as an Alarm Indicating When the Power Supply to the DGCW Pump Is Not Available, Unit 2, June 17, 1999
DCP-9800312	Install and AGASTAT Relay to Function as an Alarm Indicating When the Power Supply to the DGCW Pump Is Not Available, Unit 3, September 3, 1999
DCP-9800402	Install Unit 3 Tie-In to 345KV Switchboard Battery and Bus
DCP-9900101	Scram Instrument Volume Level Transmitter Replacement, October 19, 1999
DCP-9900117	Upgrade SBO Diesels Software/Hardware for Y2K Compliance, July 9, 1999
DCP-9900226	Install U2 Equipment Drain Sump Transmitter & Logic Change, October 26, 1999
DCP-9900257	Weld Stop Bar to Top Head Cover of Unit 2(B) Low Pressure Core Injection Heat Exchanger
DCR 9900425	Add Bushing Retaining Device to High Pressure Coolant Injection Stop Valve
E12-2-96-238	LPCI Heat Exchanger 2-1503-A Partition Plate Repair
M12-3-97-007	ECCS Room Cooler Cooling Water Supply
M12-3-97-007	ECCS Room Cooler Cooling Water Supply Modification, July 17, 1998
M12-2-97-007	ECCS Room Cooler Cooling Water Supply Modification, December 12, 1999
M12-2-96-006	ECCS Suction Strainer Replacement

Problem Identification Forms (PIFs)

D1998-00312	Safe Shutdown Lighting Errors/Incorrect Closure of NTS [Nuclear Tracking System] Item Identified by Unit One
D1998-03779	HPCI Emergency Oil Pump Failure to Start
D1998-04532	Nuclear Oversight Identifies Corrective Actions to Prevent Calculation Errors
D1998-05045	SCR's Installed Backwards During Unit 2 250VDC Battery Charger Maintenance
D1998-06129	NRC Information Notice 98-36
D1999-00043	Unit 2 125VDC Alternate Battery Electrolyte Temperature Below Tech Spec Limit Of 65 F
D1999-00083	NSRB Identified Weak Trend Investigation Reports
D1999-00085	NO Identifies Inadequate Corrective Actions
D1999-00119	Diesel Fire Pump 2/3 Failed Surveillance
D1999-00412	Washers Found in the Bottom of Check Valve
D1999-00419	Dropped Diaphragm Arch Spring Spacer on 11/12th Stage Diaphragm
D1999-00518	Erected Scaffold at Wrong Location in Dry Well
D1999-00611	Loose Bolting on U3 ECCS Suction Strainers
D1999-00767	Welding Helmet Pieces Found in 2C Condensate Pump

D1999-00955	Inadequate Ambient Temperatures/U3 125V Alt. Batteries
D1999-00978	NO Identifies Deficiencies in Scaffold Package Preparation and Execution
D1999-01073	ISO Condenser Valves Off-Normal Alarm Comes in with 3-1301-1 Valve Open
D1999-01789	Scaffold NSWP Not Adhered to and Rigging Scaffold Not Properly Built
D1999-02010	NO [Nuclear Oversight] Identified That Snubber Tests Performed During D3r15 Don't Meet Acceptance Test Criteria
D1999-02057	250 Volt Battery Voltage Drops below Tech Spec Minimum - Unplanned LCO [Limiting Condition for Operation] Entry - Potential Reportable
D1999-02338	NO Identifies Unauthorized Temporary Modification above Rx Lvl Inst. Rack 2202-8.
D1999-02315	No Identifies Welding Program Deficiencies
D1999-02697	Feedwater Reg. Valve Backup Nitrogen System Rupture Disk Found Ruptured
D1999-02750	Cup Lock Scaffolding to Be Brought on Site and Used by Untrained Personnel
D1999-02760	No Identifies Adverse Trend with Site Weld Issues
D1999-02832	Completed TMODS Not Located in Central File
D1999-02892	NO Identifies Seismic Component Not Considered During Rigging Evaluation
D1999-02946	Review of Recent PIFS Identifies Possible Adverse Trend Exists in Document Prep for Mods and DCDS
D1999-02994	2/3 DFP Tripped Due to Zebra Mussels in Strainer
D1999-03226	NO Identifies Reactor Services Training Record Storage Deficiency
D1999-03466	Nuclear Oversight Identifies Potential Unauthorized Temporary Modification
D1999-03942	Temporary Modification Not Installed as Required by Rigging Permit No. 99-049
D1999-03943	FME Found in U2 HPCI Stop Valve Strainer
D1999-03947	FME Integrity Degraded - Dropped Nut in Low Pressure Turbine Extraction Line
D1999-03952	LPB Turbine Rotor: Small Piece of Chicken Wire Found in 7th Stage
D1999-03973	Foreign Material Found in 2-7400-YF11 Filter Housing
D1999-03988	Worker Drops ED from "A" Condenser Area
D1999-03991	FME Found During Initial Disassembly of Turbine Main Stop Valves
D1999-04099	Lost TLD in D2 Torus Internals
D1999-04129	Metallic Piece Found Inside of the #5 CIV-ISV Actuator
D1999-04224	Loss of Tube Guide in B LPCI Ht Exch
D1999-04236	FME Found in the U-2 B RFP Discharge Valve
D1999-04241	Loss of FME Integrity
D1999-04242	FME Found in 2B Recirc Motor
D1999-04276	FME on Fuel
D1999-04320	FME (Cotter Pin) in 2B LPCI Hx
D1999-04336	Plastic Sleeve Left on LPRM after Put in Rx Cavity
D1999-04351	Scram Discharge Volume Header Flange Leak
D1999-04353	NO Identifies DCP Part Replacements Installed under WR Not Associated with the DCP
D1999-04375	Nuclear Oversight Identifies Discrepancies with Temporary Modification No. III-28-99
D1999-04386	Eye Bolt Dropped in Bearing #10 Lower Bearing Housing
D1999-04433	NO Identifies FME Control Violation on Refuel Floor
D1999-04435	Unsafe Scaffolding Leading to D2 Mn Cond South Center Water Box.
D1999-04455	FME in "A" Bay Condenser
D1999-04458	FME in "B" Bay Condenser

D1999-04460	FME in “C” Bay Condenser
D1999-04496	Historical Debris Found in D2 Reactor Annulus - FME
D1999-04499	FME Procedure Violation Concerning the Initiation of PIF’s for FME in a Zone 1 Area
D1999-04515	FME Found During Desluging of Torus
D1999-04587	FME in ARC’s Eductor
D1999-04628	Loss of FME Control in U1 Transfer Pool
D1999-04409	Nuclear Oversight Identifies Potential Temporary Modification
D1999-04671	Nuclear Oversight Notes Concern with OPEX, Pre-job Brief
D1999-04700	No Identified Potential FME Deficiency on Refuel Floor
D1999-04734	Software Control Problems During SBO Y2K Upgrades, November 12, 1999
D1999-04744	Unexpected Automatic Start of 2B Condensate/condensate Booster Pump Due to Low Reactor Feed Pump Suction Pressure
D1999-04746	Potential FME in the Feedwater Heater Emergency Spill Lines
D1999-04809	Bussmann MIN Fuse Rating Reduction, November 19, 1999
D1999-04905	Temporary Modification II-28-99 Deficiency
D1999-04906	Temporary Modification II-15-99 Deficiency
D1999-04925	Cribhouse Bay 3B Zebra Mussel Treatment May Not Have Been 100% Successful
D1999-05085	NO Identifies Recall of M&TE for Calibration Not Performed
D1999-05140	Brush and Piece of Duct Tape Found in Annulus
D1999-05148	Discrepancies Identified During Review of Closed Temporary Modifications
D1999-05250	LPCI [Low Pressure Coolant Injection] Inoperable
D1999-05310	Unauthorized Temporary Modification in Unit 2 Turbine Building Equipment and Floor Drain Systems
D1999-05314	ADS [Auto-depressurization System] Permissive
D1999-05359	Possible Unauthorized Temporary Modifications
D2000-00164	NRC Inspector Identifies Two Issues with Regard to Unauthorized Temporary Modifications and Deficiency in Plant
D2000-00360	Unit 2 High Pressure Coolant Injection System Stop Valve Packing Leak
D2000-00468	Missing Documentation on Temporary Modification
D2000-00415	50.59 Screening Does Not Match Temporary Modification Description
D2000-00449	NRC Concerns Brought to the Attention of Operations
D2000-00480	Turbine Building Ventilation Ice Buildup
D2000-00486	Reactor Building Ventilation Doors Propped Open Due to Excessive Snow Buildup on Inlet Plenum
D2000-00501	NRC Identified Concern During E&TS Inspection
D2000-00700	Discrepancies Identified in Eq Assessment for LOCA/LORC Event
D2000-00731	Corporate Procedure NSP-CC-3021 Is Misleading and Leads to Misclassification of Software, February 8, 2000
D2000-00736	Failure to Maintain Radwaste Solidification Building Differential Pressure

D2000-00806	Wording in Corporate Procedure NES-MS-04.1 Doesn't Match NSWP-A25(24)
D2000-00810	Diesel Fuel Oil Sample (PIFS Not Written)

Procedures

AD-AA-103	Independent Technical Reviews, Revision 0
CC-AA-10	Configuration Control Process Description, Revision 0
CC-AA-204	Control of Vendor Equipment Manuals, Revision 1
CWSP-NSP-AP-1-10	Operating Experience Instructions, Revision 1
DAN-902(3)-3-G-13	Drywell Make-Up N_2 [nitrogen] Flow High, Revision 5
DAN 923-5 G-3	U2 LPCI/CS PP Area Temp Hi, Revision 4
DAP-02-25	Design Basis Document Program, Revision 3
DAP 9-13	Procedural Adherence, Revision 6
DAP 21-07	Control and Maintenance of Fuses and Fuse Data Revision 3
DAP 21-22	Plant Modifications, Revision 3
DAP 21-21	Design Verification, Revision 1
DFPS 4123-01	Unit 1 Diesel Fire Pump Operability, Revision 15
DFPS 4123-05	2/3 Diesel Fire Pump Operability
DOP-1500-02	Torus Water Cooling Mode of Low Pressure Coolant Injection System, Revision 36
DOP 5750-01	Turbine Building Ventilation, Revision 9
DOP 5750-02	Reactor Building Ventilation, Revision 16
DOP 5750-20	Radwaste Solidification Building Ventilation System, Revision 1
DOS 8900-01	Semi-Annual High Radiation Sampling System Air Filtration Unit Operability Test, Revision 1
DSSP 0100-CR	Hot Shutdown Procedure-Control Room Evacuation, Revision 20
DTS 3900-06	HPCI and LPCI Room Emergency Room Coolers 2(3) -5747, 2(3) -5746 A(B) Performance Test Procedure
ER-AA-610	Performance Based Evaluation For Fire Protection, Revision 0
N-CSST	Seismic Scaffold Training
NEP 04-00	Roadmap to Configuration Changes Revision 4
NEP 04-01	Plant Modifications Revision 4
NEP-12-00	Roadmap - Design Control, Revision 1
NEP-12-01	Preparation, Review, and Approval of Design Input Requirements, Revision 2
NEP-12-02	Preparation, Review, and Approval of Calculations, Revision
NEP-17-04	Nuclear Engineering Plant Specific Assessment Model Update Procedure, Revision 0,
NES-MS-04.1	Seismic Prequalified Scaffolds, Revision 0
NO-AA-11	Nuclear Oversight Continuous Assessment Process, Revision 0
NSP-CC-3001	Operability Determination Process, Revision 0
NSP-CC-3021	Control of Computer Software and Services", (Rev 0)
NSP-TQ-3000	Conduct of NGG Training
NSP-AP-1002	Plant Operations Review Committee, Revision 1,
NSP-WC-3006	On-Line Maintenance, Revision 2,
NSP-ER-3018	Instrument Performance Trending, Revision 2
NSP-WC-3008	Foreign Material Exclusion, Revision 1
NSP-AP-4004	Corrective Action Program Procedure, Revision 0
NSWP-A-24	Station Scaffold Erection and Inspection, Revision 0

NSWP-A-25	Station Scaffold Installation/Modification and Removal Request, Revision 0
NSWP-A-21	Temporary Modifications, Revision 0,
OP-AA-101-301	Operational Configuration Control, Revision 0,
RS-AA-115	Operating Experience, Revision 0,
TQ-AA-117	Engineering Support Personnel
TID-MS-02	Seismic Analysis of Scaffolds, Revision 0
WC-AA-101	Work Screening and Classification, Revision 1
WC-AA-105	Post-Maintenance Testing Program, Revision 0

Operability Determinations

Operations and Maintenance Reminder (O&MR) No. 425, "Air Entrapment and Inappropriate Valve Operations During Maintenance and Calibration of Instrumentation"
NRC Information Notice No. 98-36, "Inadequate or Poorly Controlled, Nonsafety-Related Maintenance"
General Electric Service Information Letter (SIL) No. 173, Supplement 1, "Control Rod Drive High Operating Temperature"
Significant Event Notification No. 204, "Water Chemistry Induced Fuel Leaks"
WANO Significant Event Report No. 1999-2, "Spurious Containment Spray Resulting in a Severe Plant Transient"

OP-99-001:	U2/3 Diesel Fire Pump Engine Water Temperature Below Acceptance Criteria
OP-99-007:	Bolting Loose/Missing on Unit 3 ECCS [Emergency Core Cooling System] Suction Strainers
OP-99-009:	MOV [Motor Operated Valve] Wiring Problem Causing ISOL CONDR VLVS OFF NORM" [Isolation Condenser Valves Off Normal] Alarm
OP-99-017:	Snubbers Tested Outside Test Criteria
OP-99-019:	U2 250VDC Battery Charger Below Technical Specification Minimum Voltage
OP-98-030:	HPCI [High Pressure Coolant Injection] Emergency Oil Pump Failure to Start
OP-98-036:	SCR's [Silicon Controlled Rectifiers] Installed Backwards During U2 250VDC Battery Charger Maintenance
OP-98-055:	HPCI [High Pressure Coolant Injection]

Safety Evaluations

1997-03-166:	Recirculation pump MG set scoop tube
1997-04-236	Update UFSAR for 250 VDC and 125 VDC batteries
1998-01-047:	Revise UFSAR to clarify existence of high pressure piping in torus room
1998-02-138:	CCSW tie-in to ECCS room coolers
1998-02-178:	Jumpering of the HFA Relay Trip System Contacts During Testing to Prevent the Initiation of a ½ Scram
1998-02-178:	EHC low oil pressure/turbine control valve fast closure scram switches
1998-02-183:	Power increase following resolution of increased steam flow
1998-03-127:	Increased ambient temperature in shutdown cooling pump room
1998-03-234:	SBGT increased iodine release, Revision 1
1998-04-247:	Removal of reactor shield blocks at power
1998-04-272H:	250 VDC description
1998-04-282:	Unit 2 HPCI auxiliary oil pump switch modification
1998-04-286:	Time delay relay for ATWS-ARI

1999-03-123: Isolation Condenser Non-ESF [engineered safety features]

10 CFR 50.59 Screenings

1999-2563: Operator Aid for FWLC
2000-0011: DIS 1500-01, reactor low pressure ECCS permissive, Revision 15
2000-0032: Additional valves to checklist
1999-2591: Particulate and iodine sampling from SPING
1999-2458: Torque values in maintenance procedure
DOS 500-03: APRM Rod Block and SCRAM Functional Test

Temporary Modifications

II-27-99: Maintain Unit 2 Turbine Building ventilation system supply control damper in the closed position to facilitate ongoing work
II-30-99: Bypass the hydrogen addition system low flow switch due to cycling of the shut off valves
III-18-97: Sealant injection to control blowdown line leakage in the 3A Steam Jet Air Ejector Room
III-17-99: Install temporary patch on low pressure feedwater heater extraction steam nozzle to stop leakage
II-15-99: Install temporary fans to provide area and panel cooling in the station blackout diesel building
II-32-98: Provide an alternate path to exhaust air from the Unit 2 125 Volt Battery room as the installed fan is out-of-service

Technical Specification Sections

1.0 Definitions, Operable-Operability
3.5/4.5.A., Emergency Core Cooling System - Operating
3.8/4.8.A, Containment Cooling Service Water System

UFSAR Sections

6.2.1.3.2.2, Containment Short-Term Response to a (DBA) LOCA for Minimum NPSH Available, Revision 3
6.2.1.3.2.3, Containment Long-Term Response to a Design Basis Accident, Revision 2
6.2.2, Containment Heat Removal System, Revision 2
6.3.2.2, Low Pressure Coolant Injection Sybsystem, Revision 2
9.2.2, Service Water System, Revision 2
9.4.6, Emergency Core Cooling Ventilation System, Revision 3

Meeting Minutes

Dresden Station PORC Meeting Minutes of October 21, 1999
Dresden Station PORC Meeting Minutes of December 9, 11, 13, 16, 20, 22, 28, 30, 1999
Dresden Station PORC Meeting Minutes of January 3, 17, 20, 2000
Dresden Nuclear Safety Review Board Meetings (January 5-6, 1999).
Dresden Nuclear Safety Review Board Meetings (April 26-27, 1999).
Dresden Nuclear Safety Review Board Meetings (November 9-10, 1999).
Dresden Nuclear Safety Review Board Meeting (July 27-28, 1999).

Correspondence

GE NEDC-30844A, March 1988, "BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3"
GE NEDC-30851P-A, March 1988, "Technical Specification Improvement Analyses for BWR Reactor Protection System"
Various Correspondence Between Commonwealth Edison and the NRC Related to GL 83-28, Item 4.5.3
System Health Indicator Programs (SHIP) Report for November 1999 (dated 12/29/99)
Event Screening Meeting Notes, February 8, 2000
Nuclear Oversight (January - December) 1999 Corrective Action Program and Assessment Report
SHIP Detail Text Reports for December 1999 for Low Pressure Coolant Injection (LPCI), High Pressure Coolant Injection (HPCI), 125VDC Batteries, 250VDC Batteries
Diesel Generator Fuel Oil Test Reports (1 year)
Root Cause Report: Foreign Material Sucked into Two Condensate Pumps Due to an Inadequate Inspection/Cleanup Following Work Activities Inside the Condenser
NRC Inspection Report 50-237/249/98003(D.P.)
Dresden Nuclear Power Station-Trend Analysis Report (January - December 1999)
Dresden Station Open Chronic Problem Summary (as of December 23, 1999)
DOC ID#0005987361, "Binding of Valve 3904-A(B)(C), RBCCW Temperature Control Valve", July 16, 1999
DOC ID#0006089367, "System Health Indicator Program (SHIP) Report - November 1999", December 29, 1999
Root Cause Report No. 20906, Revision 0, "Adverse Trend In Temporary Modifications Due to Organizational and Programmatic Deficiencies Results in Procedure Adherence Violations"
CHRON Letter No. 211656, dated October 28, 1994, "Walkdown Report–Radwaste and High Range Sampling System Heating and Ventilation Systems"
Heating and Ventilation Controls Technical Position Paper No. HVAC-TI-002, dated October 6, 1997
Memorandum from B. Bohlke to P. Chabot, dated February 9, 2000, Regarding the Installation of a Retainer in a Valve Under a Work Request Versus a Design Change Package
Memorandum from Atwood and Morrill (P. Syrakos) to N. Radloff, dated May 15, 1991, Regarding Construction of Vushing for High Pressure Coolant Injection System Turbine Stop Valve
Memorandum from Atwood and Morrill (J. Peters) to B. Geier, dated January 21, 2000, Regarding Retaining disk for High Pressure Coolant System Stop Valve
Memorandum, The Current State of the ComEd Welding Program, November 23, 1999

Miscellaneous Documents

ACAD 98-004, “Guidelines for Training and Qualification of Engineering Personnel,” May 1998
General Electric Design Specification No. 22A1031, Revisions 0 and 1, dated December 27, 1965 and August 22, 1969, respectively
Design Specification ENC-QE-76.5, Plant Ventilation, Cooling and Heating Design Specification, August 22, 1969
DBD-DR-172A, Low Pressure Coolant Injection System, Revision A, December 20, 1995
Design Basis Document DBD-DR-006, Revision A, “125/250VDC Systems”
Charter and Interface for the Engineering Rapid Response Team (RRT)
Plant Engineering 1 Handbook, Revision 0
Work Package Nos. 990137449-01 and -02, both dated January 21, 2000, “Six Foot Steam Plume From Packing with High Pressure Coolant System Operating”
Vendor Equipment Technical Information No. V-047, “Steam Turbine Drive for High Pressure Coolant Injection Pump”
Atwood and Morrill Vendor Drawing No. 20747-H, “High Pressure Coolant System Turbine Stop Valve Assembly”
AR 00016412-77 NOA 12-99-OP10 FME Assessment
CARB Meeting Package, January 27, 2000
DES 4153-04, D2 18M DATR Safe S/D Emerg Light Discharge Test (Surveillances for 1999)
Follow-up Investigation of Foreign Material in U2 Condensate Pumps
Lesson Plan dated July 1, 1998, for Training on Changes to the Dresden Plant Specific Assessment Model