U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Report Nos. 50-315/91014(DRP); 50-316/91014(DRP)

Docket Nos. 50-315; 50-316 License Nos. DPR-58; DPR-74

Licensee: Indiana Michigan Power Company
1 Riverside Plaza
Columbus, OH 43216

Facility Name: Donald C. Cook Nuclear Power Plant, Units 1 and 2

Inspection At: Donald C. Cook Site, Bridgman, MI

Inspection Conducted: June 15 through July 22, 1991

Inspectors: J. A. Isom

D. G. Passehl

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Approved By: B. L. Jorgensen, Chief
Reactor Projects Section 2A

JUL 30 1991
Date

Inspection Summary

Inspection from June 15 through July 22, 1991 (Report Nos. 50-315/90014(DRP); 50-316/90014 (DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of: plant operations; maintenance and surveillance; safety assessment/quality verification; engineering and technical support; actions on previously identified items; security; radiological controls; and, reportable events. A management meeting was held at the NRC Region III office between NRC and licensee representatives on July 16, 1991.

Results: No violations or deviations were identified in any of the eight areas inspected. The inspection disclosed no notable weaknesses in any of the eight areas. The inspection noted that the quality of the self-assessment performed by the maintenance department with regard to performance indicators and the maintenance improvement plan was a strength.

Plant Operations:

During this reporting period, both Unit 1 and 2 operated essentially at 100 percent power with no major operational problems. Late in the inspection period, the licensee identified a potential failure scenario for their diesel

generators (DGs) caused by a tornado. The licensee was unable to determine whether the DG combustion intake and exhaust lines and the DG room ventilation system could withstand the high winds or vacuum conditions caused by a tornado. Consequently, the licensee made a conservative operational decision and declared all DGs inoperable. The licensee requested a Temporary Waiver of Compliance from the NRC to allow their staff to perform calculations for the purpose of determining whether the DGs could survive the effects of a tornado. Interim compensatory actions and training were initiated. Considering low event probability and compensatory actions, a Temporary Waiver of Compliance was verbally granted until an exemption from General Design Criterion 2 of 10CFR50 Appendix A could be processed pursuant to 10CFR50.12.

Maintenance and Surveillance:

The inspector's review of the surveillance and maintenance activities during this reporting period found that most of the activities were performed satisfactorily. The maintenance self-assessment of their performance indicators was noted as a strength.

DETAILS

1. Persons Contacted

a. Management Meeting - July 16, 1991

American Electric Power/Indiana Michigan Electric

D. H. Williams, Jr., Senior Executive Vice President, AEPSC
E. E. Fitzpatrick, Vice President, Nuclear Operations, AEPSC
T. O. Argenta, Assistant Vice President, Nuclear Engineering, AEPSC
A. A. Blind, Plant Manager
P. A. Barrett, Director, Quality Assurance, AEPSC
B. P. Lauzau, Senior Engineer, Nuclear Safety & Licensing, AEPSC
W. G. Sotos, Senior Engineer, I&C Nuclear Engineering Depart, AEPSC
D. R. Williams, Manager, RAD Support, AEPSC
H. A. Ruggles, Senior Engineer, Major Equipment Section, AEPSC
P. G. Schoepf, Nuclear Engineering Department Liaison, IMP
D. C. Loope, Radiation Protection Supervisor

Nuclear Regulatory Commission (NRC)

A. B. Davis, Regional Administrator, Region III
H. J. Miller, Director, Division of Reactor Safety, Region III
R. J. Barrett, Acting Deputy Director, DRP, Region III
T. G. Colburn, Licensing Project Manager, NRR
W. O. Long, Licensing Project Manager, NRR
L. B. Marsh, Director, PD III-1, NRR
R. N. Gardner, Section Chief, Plant Systems Section, Region III
B. L. Jorgensen, Chief, Projects Section 2A, Region III
E. R. Schweibinz, Senior Project Engineer, Region III
J. A. Isom, Senior Resident Inspector
R. A. Westberg, Reactor Inspector, Region III
C. A. Gainty, Reactor Inspector, Region III
H. A. Walker, Reactor Inspector, Region III

b. Routine Inspection

*A. A. Blind, Plant Manager
*J. E. Rutkowski, Assistant Plant Manager-Technical Support
L. S. Gibson, Assistant Plant Manager-Projects
*K. R. Baker, Assistant Plant Manager-Production
*B. A. Svensson, Executive Staff Assistant
J. R. Sampson, Operations Superintendent
*P. F. Carteaux, Safety and Assessment Superintendent
T. P. Beilman, Maintenance Superintendent
*G. A. Weber, Technical Superintendent-Engineering
*T. K. Postlewait, Design Changes Superintendent
L. J. Matthias, Administrative Superintendent
J. T. Wojcik, Technical Superintendent-Physical Sciences
M. L. Horvath, Quality Assurance Supervisor
D. C. Loope, Radiation Protection Supervisor

The inspector also contacted a number of other licensee and contract employees and informally interviewed operations, maintenance, and technical personnel.

*Denotes some of the personnel attending the Management Interview on July 19, 1991.

2. Plant Operations (71707, 71710, 42700)

Routine facility operating activities were observed as conducted in the plant and from the main control rooms.

The performance of licensed Reactor Operators and Senior Reactor Operators, of Shift Technical Advisors, and of auxiliary equipment operators was observed and evaluated including procedure use and adherence, records and logs, communications, shift/duty turnover, and the degree of professionalism of control room activities. The Plant Manager, Assistant Plant Manager-Production, and the Operations Superintendent were well-informed on the overall status of the plant, made frequent visits to the control rooms, and regularly toured the plant.

Evaluation, corrective action, and response to off-normal conditions or events, if any, were examined. This included compliance with any reporting requirements. Additionally, observations of the control room monitors, indicators, and recorders were made to verify the operability of emergency systems, radiation monitoring systems and nuclear reactor protection systems, as applicable.

a. Unit 1 operated routinely throughout the inspection period at essentially 100-percent power. There were no significant operational difficulties. The licensee's investigation into the June 10, 1991 electrical arcing event (ref. NRC Inspection Report 50-315/91011; 50-316/91011(DRP), Paragraph 2.a) was incomplete at the close of this inspection. The event will be addressed further in the next routine resident inspection report.

b. Unit 2 began the inspection period at 100-percent power and operated essentially at full power throughout this inspection period. Reactor power was briefly lowered to 81-percent for moisture separator reheater repairs from June 28 to July 1, 1991. Reactor power was again briefly lowered to 54-percent power from July 5 to July 7, 1991, for feedwater and main turbine condenser waterbox cleaning. Reactor power was lowered to and maintained at 97-percent from July 7, 1991, through the end of the inspection period, based on the licensee's calculations that the unit had reached its thermal discharge effluent limitation. There were no significant operational difficulties with Unit 2.

c. The inspector reviewed Operating Memo 89-107(A), "Operating at ESW (Essential Service Water) Temperatures Above 85 degrees," dated August 1, 1989, and noted that the operators were operating the unit within the bounds of the Operating Memo. The memo was reissued June 28, 1991, as a reminder to plant staff of the special requirements during summer months when high lake temperatures are

expected. The Operations Department is required to begin logging the circulating water (CW) temperatures hourly on both units before CW temperature for either unit exceeds 82° F. The licensee performed analyses that determined operation of Unit 1 and Unit 2 with ESW temperatures above 85° F was acceptable, but limited to 90° F. Unit 2 was further required to reduce thermal power to no greater than 3250 MWt should ESW temperature exceed 85° F. The Unit 2 requirement was based on a containment integrity analysis; the Unit 1 requirement was based on design of the emergency diesel generator coolers.

d. On July 18, 1991, at 12:15 p.m. EDT the licensee declared an Unusual Event due to their inability to prove that certain emergency diesel generator (EDG) auxiliaries were designed to sustain the wind loadings and differential pressure associated with a design basis tornado. The licensee submitted a request for a Temporary Wavier of Compliance from the requirements of Technical Specification 3.8.1.1.b. to have two OPERABLE EDGs. The request was based on compensatory actions that would alleviate the concerns associated with wind loading and differential pressure to the EDG ventilation system. The licensee was initially granted temporary relief (verbally) by NRR from Technical Specification 3.0.3 to avoid shutting down both units. Subsequently, the licensee request was reviewed during a conference call between NRR, Region III, and the licensee. NRR then granted a temporary waiver until an exemption to 10CFR50 Appendix A, GDC 2 (Design Basis for Protection Against Natural Phenomena), could be processed pursuant to 10CFR50.12. The licensee exited the Unusual Event at 2:20 p.m. EDT.

No violations, deviations, unresolved or open items were identified.

3. Maintenance/Surveillance (62703, 61726, 42700)

Corrective maintenance activities in the plant were inspected. The focus of the inspection was to assure the maintenance activities reviewed 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 post maintenance testing was performed as applicable.

Additionally, the inspector reviewed Technical Specifications required surveillance testing as described below and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were properly accomplished, that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The following activities were inspected:

a. The inspector reviewed the June 14, 1991 event when both Unit 2 Essential Service Water (ESW) trains were declared INOPERABLE when maintenance work was started on the expansion joint of the wrong train. The licensee entered Technical Specification (T/S) 3.0.3 for 37 minutes until a train of ESW was returned to OPERABLE status. The licensee subsequently performed an evaluation of the operability of the ESW system during the event and concluded the ESW system would have remained OPERABLE. The event was reported to NRC in a Licensee Event Report (LER), which will be reviewed by NRC during a future inspection.

While Unit 2 was at 100 percent power, the ESW Train B was drained, depressurized, and declared inoperable to replace a degraded expansion joint on the ESW header. The associated T/S Limiting Condition for Operation (LCO) required that the train be returned to OPERABLE status within 72 hours. Train A was intended to remain OPERABLE throughout the work.

At about 6:00 a.m. on June 14, 1991, maintenance technicians began removing the alignment and connecting bolts from the flanges of the expansion joint labelled "west" (Train B). At 12:40 p.m., after removing the bolts from the flanged connection, the licensee determined that the "east" (Train A) and "west" expansion joint labels were reversed. Train A was declared INOPERABLE and T/S 3.0.3 (one hour to begin shutdown) was entered. At 1:17 p.m. the Train A expansion joint flange bolts were replaced and torqued. Train A was then declared OPERABLE and T/S 3.0.3 was exited.

The inspector's review found several factors that caused the event in addition to the mis-labelled expansion joint. These included lack of communication between workers in the field and the on-shift supervising personnel, lack of supervisory presence in the field, and a misunderstanding of the physical indications which gave evidence that the incorrect ESW train was breached.

The Operation's Department performed a thorough Problem Report (No. 91-0737) investigation, and identified several causes for the event that included:

(1) Incorrectly labelled expansion joints. It appeared that labelling was not doubted (there have been few labelling errors in the past) until all other possibilities had been exhausted. For example, boundary valves suspected of leakby were tightened more, the drain valve was verified to be unclogged, and the Train B header pressure was verified to be zero.

(2) Not believing indications. Although the "W" ESW header was verified to be depressurized, the force of water spray from the expansion joint and the fact that it did not dissipate were indication that the expansion joint was still under pressure. Although the Maintenance personnel at the job site and an Auxiliary Equipment Operator (AEO) had thought that the

expansion joint was still pressurized based on this indication, they accepted suggestions from the Assistant Shift Supervisor and the Unit Supervisor that the water spray was probably from either a head of water that had to be drained, isolation point leakby, or a combination of both.

(3) Unusual Plant Configuration. The upstream and downstream piping from the expansion joint were buried in concrete. This made it extremely difficult or impossible to visually check piping from the joint to the associated drain point.

The licensee's preventive actions included a walkdown of all Unit 1 and Unit 2 EDG supply and return line ESW expansion joints. The labels for the Unit 2 return line expansion joints were determined to be reversed. This labelling problem was also corrected. Additionally, a "lessons learned" memo was issued that made several points, including:

(1) The benefit of in-Plant Operations supervisory involvement.

(2) Expectations for component draining.

(3) The importance, from a personnel safety aspect, of keeping some fastening devices loose but in place until it is positively known that it is safe to remove the component.

(4) The importance of ensuring that Operations personnel clearly understand any abnormal conditions which are observed and the need to pursue action until concerns are resolved.

The licensee stated additional verifications would be performed on similar systems involving buried or embedded piping where a visual walkdown of the piping could not credibly ensure labelling. These additional verifications would only be done on those systems that have not previously received such verifications.

b. The inspector's observation of the work (Job Order A31876) on the Unit 1 Reciprocating Charging Pump to repair a water leak through cover plugs (zinc plugs) on the bearing oil cooler indicated that the cause of the leak was that the zinc plugs had been depleted to the point that they caused the cooling water to leak from the bearing oil cooler. The inspector noted that the zinc plugs (provided for cathodic protection of the oil cooler) were completely consumed and in the form of a spongy crust. The licensee indicated the oil cooler plugs for both the reciprocating and centrifugal charging pumps were not routinely replaced because they were not on a preventive maintenance schedule. Instead, they are replaced when a corrective maintenance work order is requested to repair the leaking water condition. The licensee issued Problem Report number 91-0782 to evaluate whether the replacment of zinc plugs for these coolers on a periodic basis is warranted, and whether there are other heat exchangers with depleted zinc plugs in more adverse environments.

Otherwise, the inspector noted the technicians who performed the work were knowledgeable and qualified and the required tools were at the job site.

c. The inspector observed the following surveillances.

**1 IHP 4030 STP.035, "Reactor Coolant Pump No. 4 Undervoltage Bus 1A Surveillance Test." Rev. 9, December 4, 1989.

**1 IHP 4030 STP.037, "Reactor Coolant Pump No. 2 Underfrequency Bus 1C Surveillance Test." Rev. 6, July 3, 1986.

**2 IHP 6030 IMP.250, "4 kV Diesel Start, 4 kV ESS Bus Undervoltage Relay Calibration." Rev. 8, August 21, 1990.

**2 MHP 4030 STP.035, "2 AB Battery Quarterly Surveillance." Rev. 4, February 15, 1990.

The inspector observed that the surveillances were conducted properly, the procedures were on hand, the data sheets were completed and the Measuring and Test Equipment (M&TE) used were in calibration. The technicians appeared to be knowledgeable and qualified for the jobs performed.

The inspector noted a minor discrepancy during the calibration of the 4 kV ESF Bus Under Voltage Relays, (**2 IHP 6030 IMP.250). The "as-found" reset pick-up voltages for 12 relays were below the acceptance criteria and yet no condition report was generated to ensure further evaluation. The measurements were in the range of 98.8 to 99.6 volts AC and the procedure specified acceptance criteria of 100.0 to 101.0 volts AC. Although these reset pick-up voltage values were associated with the reset of these undervoltage relays and, consequently, appeared to have no safety significance (did not affect the detection of the 4 kV ESF Bus undervoltage condition) the inspector reviewed the calibration reports for these relays for the previous two months to determine if similar conditions had been unreported. The inspector found that the reset pick-up voltages of all these relays were found to be higher (101.3 to 102.0 volts AC) during their calibration check in May 1991, while all these relays were found to be within the calibration tolerance during the month of April 1991. The I&E Department had not generated a condition report so that these relay drifts could be properly evaluated. This observation was referred to the I&E department and discussed at the management interview.

No violations, deviations, unresolved or open items were identified.

4. <u>Safety Assessment/Quality Verification (37701, 38702, 40704, 92720)</u>

a. The inspector noted the assessment performed by the Maintenance Department of the performance indicators and the implementation of the maintenance improvement plan was a strength. Since April of

1991, the Maintenance Department has issued a Monthly Management Report which contains graphs of various performance indicators such as numbers of:

Total Open Job Orders
Job Orders - aging by Trade
Control Room Job Order Tags
Job Orders in Planning
Job Orders in Planning - 60 days
Job Orders in Engineering - 30 days
Job Orders on Hold for Parts - 60 days
Job Orders Ready For Scheduling
Corrective Maintenance Job Orders - aging
Post Maintenance Tests Incomplete
Preventive Maintenance Jobs - Past Due By Age

Additionally, the report contained an assessment section by a Maintenance Program Analyst of these performance indicators. The inspector's review of the assessment found them to be insightful and informative.

Although one could question the characterization of some of the issues in the evaluation/analysis section, the inspector noted that critical self-evaluation of the effectiveness of the maintenance program was a positive indication of management's desire to improve in this area. In this context, the inspector believed that performance of this assessment was a strength. Some of the issues raised in the evaluation/analysis section were:

(1) Lack of significant progress being made to reduce the total number of open non-outage corrective maintenance job orders.

(2) Difficulty in planning/scheduling corrective maintenance job activities because of resource constraints and lack of spare parts.

Although at present the inspector noted that the trends for some of these performance indicators were not positive, discussions with the program analyst indicated that improvements to reverse these trends were being made, but positive results were yet to be obtained. Additionally, the inspector was informed by licensee management that despite the increase in the number of open non-outage job orders, the licensee had made improvements in the number of open non-outage safety-related job orders. The inspector agreed with the views of the program analyst that because of new program initiatives which required maintenance support, improvement in the performance indicators were yet to be realized and various program changes, when fully implemented and realized, would improve the maintenance (planning and scheduling) process at the facility.

b. In the process of closing out various open items, the inspector noted that in some cases it was difficult to obtain sufficient information needed for closure of unresolved or open items.

Additionally, in one case, the inspector noted that a recommended engineering resolution, to resolve containment spray pump testing concerns, had yet to be completed (See Paragraph 6.h). The difficulty encountered in obtaining sufficient documentation to close the open items appeared to be particularly applicable for the older unresolved or open items. It appeared to the inspector that this difficulty stemmed partly from not knowing to whom (department or individual) responsibility for closure of these unresolved or open items had been assigned. Discussions with the licensee and the inspector's review of the licensee's problem identification program entitled "Condition Reports and Plant Reporting" procedure, PMI-7030, Revision 17, May 23, 1991, indicated that currently neither unresolved nor open items are required to be tracked by the responsible department for resolution. The "Condition Reports and Plant Reporting" procedure does, however, require that items identified as violations or emergency preparedness weaknesses at NRC inspection "exit" meetings have condition reports initiated by the department responsible for preparation of meeting minutes.

The inspector noted that timely resolution of unresolved issues which have a potential to result in a violation appeared to be prudent in that the resolution may either correct existing deficiencies or prevent future recurrence of similar problems. Additionally, although open items do not require responses from the licensee, the inspector noted that exchange of information needed to close these open items appeared to be beneficial to both the inspector and the licensee. The licensee stated that in the future, Unresolved Items would be investigated via the "Condition Report" tracking system.

No violations, deviations, unresolved or open items were identified.

5. Engineering and Technical Support (71710)

The inspector monitored engineering and technical support activities at the site and, on occasion, as provided to the site from the corporate office. The purpose of this monitoring was to assess the adequacy of these functions in contributing properly to other functions such as operations, maintenance, testing, training, fire protection and configuration management.

The inspector reviewed the status of the licensee's Large Bore Piping Reconstitution Program (LBPRP). The program is being implemented to obtain accurate as-built information on all safety-related large bore piping systems, and will be used to reconstitute the design basis of the plant as described in the UFSAR. The information is being obtained through detailed field walkdowns to assure that the current design documents can be utilized for re-analysis of the piping and pipe support systems for the LBPRP.

The licensee is roughly 54 percent complete with the actual physical walkdowns, which began in March 1991. The Auxiliary Building walkdown is scheduled for completion by the end of July 1991. The remaining walkdowns, those of the piping systems inside containment, are scheduled

for completion during the February 1992 and July 1992 refueling outages for Units 1 and 2, respectively. The completed design basis reconstitution (including design calculations and updated drawings) is scheduled for completion in late 1996 or early 1997.

No violations, deviations, unresolved or open items were identified.

6. Actions on Previously Identified Items (92701, 92702)

a. (Closed) Unresolved Item 50-315/89018-01: During review of a licensee problem report on a containment airlock door seal leak test failure, the inspector identified and questioned the acceptability of wiping down and greasing the containment airlock door seals before performing the airlock door seals leakage test. The inspector viewed these activities as test preconditioning. As a corrective action, the licensee revised "3-Day Airlock Door Test" procedure, **12 THP 4030 STP. 227, Revision 5, September 28, 1989, to include a statement that the use of grease or lubricant to improve the performance of airlock door seals is not acceptable. The licensee since then has conducted containment airlock door leak tests satisfactorily without use of any lubricants.

b. (Closed) Open Item 50-316/88009-01: The inspector's review of completed job order packages identified a valve stem which was installed in June 1987 was found bent in November 1987. The licensee was asked to investigate the failure of this valve stem in the Unit 2 Containment Spray System. The licensee's investigation found that they could not conclusively determine the root cause for the bent stem. The licensee stated that the most likely cause was the valve being over torqued with the hand wheel. As a corrective action to prevent recurrence, the operations personnel received training on hand operation of motor operated valves.

c. (Closed) Open Item 50-316/89002-01: The inspector's review of "Maintenance Procedure for the Disassembly, Repair, and Reassembly of the Turbine Driven Auxiliary Feed Pump Governor Valve," **12 MHP 5021.056.008, Rev. 0, Jan 22, 1987, found that diagrams used in the procedure did not appear to provide sufficient detail concerning where measurements on the various governor components were to be taken. The inspector's review of the current revision of the procedure "Maintenance Procedure for the Disassembly, Repair, and Reassembly of the Turbine Driven Auxiliary Feed Pump Governor Valve," **12 MHP 5021.056.008, Rev. 2, June 8, 1990, found that the procedure appeared to be sufficiently detailed for a knowledgeable mechanic to determine where component measurements should be taken.

d. (Closed) Part 21 Notification 50-315/86-001-PP and 50-316/86-001-PP: On January 9, 1986, NRC received a Part 21 notification from Westinghouse regarding an error in the reactor vessel water level instrumentation system (RVLIS) for the non-upper head injection analog version of RVLIS. The review of the RVLIS system during resolution of the steam density compensation issue led to the discovery that insufficient electronic circuitry existed to ensure proper compensation, for all possible temperatures and pressures, on

one of the three level ranges. Additionally, Westinghouse found inconsistencies in their system manual guidelines for scaling RVLIS. Westinghouse estimated that the circuit inadequacy, which is small below 400 pounds per square inch (psi), might cause an error of as much as 20 percent of the vessel height at maximum pressure of 2500 psi.

The inspector's review of the licensee's February 27, 1986, memorandum from the lead engineer responsible for resolution of this Part 21 issue and the July 23, 1987, memorandum from the Nuclear Safety and Licensing section indicated that the modification to the electronics had been performed by Westinghouse Field Services and the scaling guidelines had been implemented.

e. (Closed) Part 21 Notification 50-315/87-001-PP and 50-316/87-001-PP: During modification work on six BBC Brown Boveri transformers for Unit 1 in May 1987, the licensee discovered pitting and corrosion on bolted connections between the aluminum buses and tinned copper braids on the Brown Boveri Company (BBC) dry type transformers. These transformers were being taken from storage to be installed in Unit 1 and the problem was discovered during inspection of the transformers before installation. Because the conditions found on the transformers could potentially be applicable to other similar transformers supplied by BBC, the licensee made a Part 21 Notification to the NRC on July 27, 1987.

The Transformer and Switch Division of Brown Boveri Equipment, Inc. determined that the corrosion was caused by an acid flux used on the braided flexes during the tinning process. Because the flexes were not cleaned as thoroughly as they should have been after they were tinned, the acid flux residue on the flexes attacked the aluminum bus and caused the corrosion. The BBC vendor recommended that the licensee clean the transformer connection surfaces on the buses and the copper braids and that these surfaces be coated with a corrosion inhibitor. The field repairs were made to the Unit 1 transformers in June of 1987 and reinspection of BBC transformers installed on Unit 2 was recommended by the licensee in order to determine whether similar problems existed. Because the infra-red temperature readings did not indicate cause for immediate concern, the Unit 2 dry transformer bus/flex braid corrosion inspections for the Unit 2 BBC transformers were not performed until the 1988 Refueling/Steam Generator Replacement Project Outage.

The inspection of the Unit 2 transformer found no visible evidence of corrosion or pitting on any connection of any transformer. Nonetheless, following inspection and testing of the transformers, contact surfaces were cleaned and coated with a corrosion inhibitor compound.

f. (Closed) Part 21 Notification 50-315/88-001-PP and 50-316/88-001-PP: The Limitorqe Corporation notified the licensee on March 30, 1988, that the torque switches on some Model SMB-00 valve operators in use at the D.C. Cook plant had not been qualified for nuclear safety-related service. As a result, the licensee

performed a review of their motor-operated valves to determine which Model SMB-00 valve operators were affected. The review identified a total of 70 valves, 34 valves in Unit 1 and 36 valves in Unit 2, which required a torque switch replacement. The licensee installed qualified torque switches on all but two valve operators by February 22, 1989. After a detailed evaluation, the licensee determined that torque switches on valves 1-IMO-320 and 2-IMO-320 did not have to be environmentally qualified and consequently, they were not replaced.

g. (Closed) Part 21 Notification 50-315/89-001-PP and 50-316/89-001-PP: On February 8, 1989, during conduct of routine cleaning and inspection of circuit breakers installed in the 4 kV distribution system for Unit 1, a BBC 5HK250 breaker, which had been removed from service for testing, failed to close when the closing circuit was energized. The breaker supplies the Unit 1 East residual heat removal pump and is required to close to perform its safety function. On February 27, 1989, a second BBC 5HK250 breaker also failed to close during routine testing. Because the failures of these breakers were determined to be caused by aging and contamination of the grease on the breaker closing mechanism, and because similar breakers of about the same age were used in safety-related applications elsewhere in the industry, the licensee submitted a 10 CFR 21 report.

The licensee identified 18 type 5HK250 breakers in each unit for a total of 36 breakers which were required to close in order to perform a safety-related function. The systems affected were high-head and intermediate-head safety injection, auxiliary feed water, containment spray, residual heat removal, essential service water, component cooling water, and emergency diesel generators. The licensee performed inspection, cleaning and lubrication of all 36 breakers by March of 1989.

The licensee's investigation into the causes of the breaker failures found that the breaker maintenance procedure did not require any cleaning and lubrication of the breaker closing mechanisms. This was because the cleaning and lubrication of these breaker closing mechanisms were not addressed in the vendor manual. The licensee's discussion with the vendor revealed that periodic cleaning and lubrication of the closing mechanism was not addressed in the BBC technical manual because the lubrication performed at the factory was believed to be sufficient for the life of the breaker. However, after these failures were reported, the vendor recommended a change to their technical manual to periodically clean and lubricate the breaker closing mechanisms. To prevent recurrence of similar breaker failures, the licensee revised "Inspection and Repair of 4 kV Breakers," procedure **12 MHP 5021.082.001, Revision 7, April 17, 1989, to include steps for proper cleaning and lubrication of the closing mechanisms.

h. (Open) Open Item 50-316/89009-01: During a Unit 2 Containment Spray System operability test, the inspector raised a concern that because of the difficulty in establishing a stable recirculation flow for the surveillance, it may be difficult to verify compliance with Technical Specification requirements or to detect

pump performance changes. The operability of the containment spray system is verified by the containment spray pump developing a discharge pressure of 255 psig or greater at a flow of 700 gpm or greater while on recirculation flow. Once the required recirculation flow is established, pump discharge pressure is measured. The inspector noted that after the manual recirculation valve was throttled to obtain flow within the required range of 77 to 81 divisions, the flow gauge oscillated irregularly over a band of 10 to 20 or more divisions requiring the operator to visually average the oscillations to arrive at the value of the indicated flow.

The inspector found that the licensee's actions to reduce or to eliminate the flow oscillations were incomplete and that neither Unit 1 nor Unit 2 containment spray pump instruments adheres to Engineering Control Package (ECP) 1/2-I2-03. The inspector was informed that the problem with the flow gauge had been identified prior to being noted as an open item (50-316/89009-01) in an NRC inspection report and that ECP 1/2-I2-03 had already been issued on June 30, 1987, to address this problem. The ECP recommended that the flow gauges in both units be replaced with 0-300 inches water bellows assemblies and 0-1700 GPM square root scales. The 0-300 inches water bellows has a much stronger spring than the current bellows and its installation is believed to either dampen or eliminate the flow oscillations. The installation of the 0-1700 GPM gauges would eliminate the math and plot calculations presently necessary to translate the divisions on the flow meter into GPM containment spray pump flow. The licensee plans to implement ECP 1/2-I2-03 through a minor modification process. Until the minor modification is complete, 50-316/89009-01 will remain open.

No violations, deviations, unresolved or open items were identified.

7. Security (71707)

Routine facility security measures, including control of access for vehicles, packages and personnel, were observed. Performance of dedicated physical security equipment was verified during inspections in various plant areas. The activities of the professional security force in maintaining facility security protection were occasionally examined or reviewed, and interviews were occasionally conducted with security force members.

On July 14, 1991, at 12:56 p.m. a site security guard was making rounds and noticed a small box in the licensee's cafeteria marked with the words "boom, you're dead." The security force executed their contingency procedures and notified the Berrien County Sheriff's Department bomb squad, the Federal Bureau of Investigation, and NRC. The box was subsequently x-rayed and nothing was found other than used packing material. The licensee began an investigation and NRC Region III security specialists were given detailed information for follow-up action.

No violations, deviations, unresolved or open items were identified.

8. Radiological Controls (71707)

During routine tours of radiologically controlled plant facilities or areas, the inspector observed occupational radiation safety practices by the radiation protection staff and other workers.

The inspector noted good licensee performance in the areas of personnel contamination events and personnel exposure. The licensee recently revised the year-end goals for personnel contaminations from 234 to 90; and personnel exposure from 146 person-Rem to 92. The licensee's current performance was noted to be 38 personnel contaminations (for the year) and total exposure of 49.057 person-Rem.

No violations, deviations, unresolved or open items were identified.

9. Reportable Events (92700, 92720)

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and, as applicable, the immediate corrective action and appropriate action to prevent recurrence had been accomplished.

(OPEN) LERs 50-315/89002-11, 50-315/90013-11, and 50-316/90006: Failure of the Main Steam Safety Valves (MSSVs) to meet Technical Specification lift setpoint requirements. The inspector reviewed the LERs, each of which described instances when several MSSVs failed to lift at setpoints required by plant Technical Specifications. The licensee attributed the events to incompatibility of the required T/S setpoint tolerance to the setpoint repeatability inherent to the MSSV design. In all cases, the as-found lift setpoints would not have affected the pressure relief capacity of the affected Steam Generators nor would there have been the potential for an overpressurization of the Main Steam System beyond its design criteria. The licensee's immediate corrective actions were to reset the MSSV lift setpoints to within their specified ranges as required by procedure.

The inspector reviewed proposed preventive actions and the as-found lift setpoints in the respective LERs. The licensee's proposal is to change the current T/S lift setpoint values on the MSSVs from plus or minus one percent, to plus three and minus one percent. Assuming the T/S change is granted, the inspector noted that there would still be some safety valves which would lift outside the new proposed tolerance range, and hence an LER would still be required. It appeared to the inspector that the proposed corrective actions as described in the LERs may be inadequate. Until the licensee resolves this potential concern, these items will remain open.

10. Management Meeting (30702)

A management meeting, attended as indicated in paragraph 1.a. was conducted at the Region III office on July 16, 1991. The purpose of the meeting was to discuss licensee performance and initiatives.

The topics presented by the licensee staff were:

AEP nuclear short and long term goals

Progress made in the maintenance area

Outage management organization and effectiveness

Management of shutdown risks

Reactor protection system instrumentation replacement

Radiation protection program

Additionally, the developing issue regarding potential inoperability of diesel generators for both Unit 1 and 2 in the event of a design basis tornado was discussed. The licensee indicated that as a result of their readiness review for the upcoming electrical distribution system functional inspection, they had concerns regarding whether their DGs would be operable under worst case tornado scenarios (See Paragraph 2.d.).

11. Management Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) on July 19, 1991, to discuss the scope and findings of the inspection. In addition, the inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary.