U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/92018(DRP); 50-316/92018(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: September 16, 1992 through October 27, 1992

Inspectors: J. A. Isom
D. J. Hartland

Approved By: Edward R. Schweibinz for B. L. Jorgensen, Chief
Reactor Projects Section 2A

11-6-92
Date

Inspection Summary: Inspection from September 16, 1992 through October 27, 1992 (Report Nos. 50-315/92018(DRP); 50-316/92018(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of: plant operations; engineering and technical support; radiological controls; reportable events; actions on previously identified items; and, outages. In addition, a routine periodic management meeting was held at the plant site on October 22, 1992.

Results: Of the six areas inspected, the inspector identified a noncited violation in the reportable events area. The inspector did not identify violations or deviations in any of the other areas inspected.

The inspection disclosed strengths in the system engineer's thorough review of past emergency diesel generator start failures which identified the licensee's failure to place one of the diesel generators on increased surveillance frequency.

The inspection disclosed weaknesses in the licensee's operations surveillance program which contributed to the EDG start failure on September 28, 1992.

One Unresolved Item was identified and is discussed in paragraph 2c. Additionally, two open items were identified and are discussed in paragraphs 5d and 6a.

DETAILS

1. Persons Contacted

a. Management Meeting - October 22, 1992

American Electric Power Service Company AEPSC

D. H. Williams, Senior Executive Vice President
E. E. Fitzpatrick, Vice President, Nuclear Operations
S. J. Brewer, Manager, Nuclear Safety and Licensing
S. P. Hodge, Manager, Mechanical Systems
J. A. Kobyra, Manager, Nuclear Design
J. B. Kingseed, Manager, Nuclear Safety
D. H. Malin, Manager, Nuclear Licensing

Indiana Michigan Power/Cook Nuclear Power Plant

A. A. Blind, Plant Manager
L. S. Gibson, Assistant Plant Manager-Projects
J. E. Rutkowski, Assistant Plant Manager-Technical Support
K. R. Baker, Assistant Plant Manager-Production
J. S. Wiebe, Safety and Assessment Superintendent
D. C. Loope, Radiation Protection Superintendent
M. E. Barfelz, Nuclear Safety Analysis Supervisor
D. M. Fitzgerald, General Supervisor, Environmental
G. A. Weber, Plant Engineering Superintendent
T. K. Postlewait, Design Changes Superintendent

Nuclear Regulatory Commission (NRC)

C. J. Paperiello, Deputy Regional Administrator, RIII
W. D. Shafer, Chief, Reactor Projects Branch 2, RIII
J. A. Isom, Senior Resident Inspector, RIII
K. D. Ward, Reactor Inspector, RIII
D. J. Hartland, Resident Inspector, RIII

b. Inspection - September 16 through October 27, 1992

* A. A. Blind, Plant Manager
K. R. Baker, Assistant Plant Manager-Production
L. S. Gibson, Assistant Plant Manager-Projects
J. E. Rutkowski, Assistant Plant Manager-Technical Support
B. A. Svensson, Executive Staff Assistant
T. P. Beilman, Maintenance Superintendent
P. F. Carteaux, Training Superintendent
D. C. Loope, Radiation Protection Superintendent
L. J. Matthias, Administrative Superintendent
* T. K. Postlewait, Design Changes Superintendent
* J. R. Sampson, Operations Superintendent
P. G. Schoepf, Project Engineering Superintendent

L. H. Vanginhoven, Site Design Superintendent
* G. A. Weber, Plant Engineering Superintendent
* J. S. Wiebe, Safety and Assessment Superintendent
J. T. Wojcik, Chemistry Superintendent
M. L. Horvath, Quality Assurance 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 October 29, 1992.

2. Plant Operations (71707, 71710, 42700)

The inspector observed routine facility operating activities as conducted in the plant and from the main control rooms. The inspector monitored the performance of licensed Reactor Operators and Senior Reactor Operators, of Shift Technical Advisors, and of Auxiliary Equipment Operators including procedure use and adherence, records and logs, communications, and the degree of professionalism of control room activities.

The inspector reviewed the licensee's evaluation of corrective action and response to off-normal conditions. This included compliance with any reporting requirements.

The inspector noted the following with regard to the operation of Units 1 and 2 during this reporting period:

a. Unit 1 Summary of Operations:

At the beginning of the inspection period, the licensee had Unit 1 in Mode 6 with the core off-loaded and was continuing with the refueling outage that began on June 22, 1992. The licensee completed core reload on September 20, 1992, and the reactor was taken critical on October 25, 1992. Other outage activities are described in paragraph 7. At the end of the inspection period, the licensee had the unit in Mode 1, preparing to parallel it to the grid for the first time following the outage.

b. Unit 2 Summary of Operations:

At the beginning of the inspection period, the licensee had Unit 2 in Mode 3. The generator rotor had been removed for shipment to a vendor facility for analysis and resolution of the vibration problem. The unit was maintained in Mode 5 from September 25, 1992, through the remainder of the inspection period. The generator rotor is scheduled to be shipped back to the site on November 8, 1992.

c. Unit 2 AB EDG Low Lube Oil Pressure Trip

On September 28, 1992, while starting the Unit 2 AB Emergency Diesel Generator (EDG) for performance of a required monthly surveillance test, the EDG tripped on low lube oil pressure. The licensee subsequently discovered that the lube oil tank level indicator was reading 42 percent full, or the equivalent of 309 gallons, which was below the licensee's administrative limit of 400 gallons. The actual amount of oil in the tank, as measured by a dipstick, was only 127 gallons. A low level alarm, which should have come in at 50 percent (383 gallons), was never received. The inspector identified two concerns during followup of the event. The first concern related to the erroneous level indication and failure of the low level alarm. This is discussed briefly in paragraph 3. The other issue, concerning the failure of operations personnel to identify that the level indication had fallen below the licensee administrative limit, is discussed below.

OHI 5030, "Unit 2 Operations 5030 Surveillance," required that the EDG lube oil indicators be read once a week by an auxiliary equipment operator. To get the reading, the operator was required to temporarily valve in a non-seismic pressure gauge, which provided an indication in "% level". The operator was then required to refer to the Tech Data Book to convert the indication to the number of gallons in the tank.

The inspector reviewed the OHI 5030 surveillance records and noted that the lube oil inventory had been trending downward for several weeks and had gone down to 383 gallons, below the administrative setpoint of 400 gallons, on September 2, 1992. Three more weekly readings were taken prior to the day of the event, the last one recorded as 326 gallons on September 23, 1992. Leakage from the Before and After pump had resulted in a higher than normal leakage rate from the EDG lube oil system. A work request was initiated in May 1992 to repair the pump seal. The inspector noted that OHI 5030 did not contain any acceptance criteria for the lube oil level, nor any mechanism for identifying the adverse trend.

As immediate corrective action, the licensee began monitoring EDG lube oil level on a daily basis using a dipstick until a reliable alternative was established. The licensee also established a task team to evaluate the process/procedures for performing operator tours and reviewing data gathered.

The EDG may have been incapable of performing its intended safety function for some time before the discovery of the problem on September 28. There was available evidence to show an adverse safety condition was developing. Licensee actions involving failure to identify and correct a condition adverse to plant safety is an unresolved item.
(Unresolved Item 50-315/92018-01(DRP);50-316/92018-01(DRP)).

One unresolved item, and no violations, deviations, or inspector followup items were identified.

3. Engineering and Technical Support (37828)

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.

Erroneous EDG Lube Oil Sump Tank Level Indication

As discussed in paragraph 2.c., the Unit 2 AB EDG tripped on September 28, 1992, on low lube oil pressure. A contributing cause to the event was an erroneous lube oil tank indication, which was reading the equivalent of 309 gallons, when only 127 gallons were actually in the tank. In addition, a separate low level alarm, which should have actuated at 383 gallons, was never received.

The level indication was provided by a locally-mounted pressure gauge, which read out in "% level". The gauge was installed in June 1991 by Minor Modification 12 MM 184 to replace the existing level transmitter, which provided an indication on the EDG subpanel. The original transmitter had failed and replacement parts were unavailable. Pressure gauges were also installed on the other three EDGs to be used in the event the transmitters for those EDGs also failed. Licensee root cause evaluation of the level indicator and alarm failures, and the operability determination of the EDG at the time of the event will be reviewed by the inspector as followup to the Licensee Event Report (LER) that will be submitted in response to the event.

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

4. 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.

Radiation Surveys

On October 1, 1992, during a routine tour of the auxiliary building, the inspector noted that the routine radiation/contamination survey of the RHR pump rooms had not been performed since September 9, 1992, over three weeks earlier. The RHR system had been in service part of this period. Followup of this observation found the licensee had not performed routine surveys within their intended frequency, because they had not performed an adequate review of a procedure revision.

Some time ago, the licensee revised RPSO 004, "Radiation Survey Schedule Frequency," to reduce the required frequency of routine surveys of the RHR pump rooms (when the pumps were not operating) from semi-monthly to monthly. The previous procedure revision contained a separate stipulation that the rooms be surveyed weekly when the pumps were operating. This stipulation was intended to be reduced to semi-monthly, but it was inadvertently deleted during the revision. The licensee's procedure revision review process failed to detect the omission of the requirement. As a result, surveys of the RHR pump rooms when the pumps were operating were only being performed on a monthly basis. The licensee implemented semi-monthly surveys immediately upon being notified by the inspector.

The inspector was also concerned that, after the licensee became aware of the error and corrected it, no corrective action Condition Report was written to document the problem. Licensee internal procedures state that procedure revisions will receive a critical evaluation to ensure the document is correct. The revision in question was not correct, as discussed above, leading to the conclusion that the "critical evaluation" process failed. This deviation from the approved procedure is an example of a problem which is included in Attachment 2 of procedure PMI 7030, "Condition Reports and Plant Reporting" as requiring documentation as a Condition Report. This was noted during the Management Interview.

The inspector identified a separate concern relating to the adequacy of formal mechanisms to ensure that non-routine surveys are done on a timely basis in response to changes in plant status. Initial RHR system operation during an outage is an example. Late in the inspection period, the inspector received some radiation survey data of the RHR systems of both units, covering the period since the beginning of each of the last refueling outages. Review of the survey data, to determine if RHR operation had inadvertently caused a high radiation area without proper controls, is ongoing.

No violations, deviations, unresolved items, or inspector followup items were identified.

5. Reportable Events (92700)

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, that immediate corrective action and appropriate action to prevent recurrence had been accomplished.

Unit 1 LERs:

a. (Closed) LER 50-315/91008-LL: Four Radioactive Sealed Sources Not Leak Tested In Accordance With Technical Specifications (TS) Due to Misclassification.

The LER is being closed based on adequate licensee root cause evaluation and corrective action.

On September 24, 1991, the licensee determined that four radioactive calibration sources had not been leak tested in accordance with Technical Specifications 3/4.7.7 (Unit 1) and 3/4.7.8 (Unit 2) since they were received on site in April 1987.

The licensee determined the root cause to be that the sources were incorrectly misclassified as unsealed sources due to inadequate procedural detail. Leak tests were immediately performed and were satisfactory. In addition, all sources were evaluated to verify appropriate classification. As corrective action, the licensee updated the applicable procedure and technician training criteria to clarify the definition of a sealed source and require leak testing of all sources that exceed the activity requirements of the TS.

b. (Closed) LER 50-315/91011-LL: Emergency Diesel Generator Not Placed On Increased Surveillance Frequency When Required By Technical Specifications.

The licensee found that the Unit 1 AB emergency diesel generator (EDG) was not placed on an increased surveillance frequency period as required by Technical Specifications because of inadequate documentation of a valid start failure in December of 1990. Because the licensee had not recognized the December 1990 start failure as a valid failure, another start failure on June 3, 1991, was not recognized as the second failure within the last twenty starts. The event was discovered on April 7, 1992, by the EDG system engineer while conducting routine reviews of EDG records to become familiar with the history of each emergency diesel generator. The licensee's review of records indicated that by a January 15, 1992, EDG surveillance run, they had, with the exception of the June 3, 1991, failure, accumulated 22 successful starts, so that Unit 1 AB EDG was no longer subject to increased surveillance frequency requirements.

The inspector's review of corrective actions taken to prevent recurrence of this problem found that the licensee's new program implemented through procedure "Emergency Diesel Generator (EDG) Reliability Monitoring Program,"PMI-6080, Revision 0, July 31, 1992, should minimize the possibility of missed surveillances on the EDGs because of start failures. This new program is intended to ensure that data on all EDG demands are logged and properly evaluated. All EDG start demands, manual or automatic, are recorded in the Control Room EDG Run Log and on page 1 of Data Sheet 13 of "Diesel Generator Operability Test," **12 OHP 4030 STP.027AB/CD procedure. In addition, an Incident Report per Attachment 1 of PMI-6080, is generated for each start failure.

Based on the new program, the EDG system engineer is responsible for maintaining the EDG Reliability Monitoring Program and the Operations Department Superintendent or an Operations Production Supervisor is responsible for reviewing and approving increased frequency testing determinations specified in the Incident Reports.

The missed EDG surveillances from about June of 1991 to January of 1992 was a violation of Unit 1 Technical Specifications (TS). However, this TS violation is not being cited in a Notice of Violation because the criteria specified in Section V.G. of 10 CFR Part 2, Appendix C, (NRC Enforcement Policy) were satisfied. This LER is closed.

Unit 2 LERs:

c. (Closed) LER 50-316/91006-LL: Reactor Trip-Turbine Trip from Main Generator Protective Relay Operation During Failure of a Main Generator Output Breaker Current Transformer.

This LER is being closed based on adequate licensee root cause evaluation and corrective action.

On August 1, 1991, the Unit 2 reactor tripped as a result of a turbine trip initiated by the generator differential protective relays. The relays actuated as a result of a fault/explosion of the phase three current transformer (CT) on the main generator output breaker located in the 765 Kv switchyard.

The CT was subsequently disassembled and inspected. The licensee could not conclusively determine the origin of the fault, but suspected that insulation deterioration had begun some time before the failure. The licensee determined that annual oil samples for dissolved gasses to detect insulation degradation had not been performed since November 1988. As a result, the responsibility for scheduling the preventive and predictive maintenance for the CT's was transferred to the AEP Nuclear Organization from an offsite licensee group.

d. (Closed) LER 50-316/91007-LL: Simulator Scenario Identified Flowpath that Diverted ECCS Flow Caused By Plant Design/Emergency Response Guidelines.

This LER is being administratively closed and an Open Item initiated pending receipt and review of a revised report.

The LER documents a concern that was identified by the licensee on August 2, 1991, during a small break LOCA run on the plant simulator. At that time, the licensee identified a potential flowpath which would divert water away from the ECCS and the containment building to the VCT holdup tanks in the auxiliary

building. The licensee's analysis concluded that the amount of water that would be diverted is not significant from a core cooling and radiological perspective; however, it is a condition that is considered outside of the plant design basis.

As corrective action, in addition to revising applicable EOPs to caution operators, the licensee requested a vendor to conduct further review of the issues identified by the simulator scenario. The licensee committed to submit a revised report to document any additional corrective action by December 21, 1991. Due to delays in the completion of the vendor review, the licensee has revised the submittal date of the supplemental LER to December 31, 1992. Receipt and review of the supplemental report is an inspector followup item (Item 50-315/92018-02; 50-316/92018-02).

e. (Closed) LER 50-316/91008-LL: Containment Pressure Relief Performed with the Radiation Monitor Trip Function Blocked Due to Personnel Error.

This LER is being closed due to satisfactory licensee root cause evaluation and corrective action.

This LER documented an event that occurred on November 5, 1991, when a reactor operator trainee inadvertently opened the containment pressure relief valves to perform a containment pressure relief while the valve's associated radiation monitoring system trip function was blocked. This condition would have prevented automatic closure of the valves upon receipt of a high radiation alarm signal from the monitoring system. However, auto closure of the valves on a phase A or phase B signal, as well as the high radiation alarm capability in the control room, were available throughout the event. In addition, the licensee review of the applicable radiation monitor printouts revealed no elevated readings.

The licensee determined the root cause to be inadequate control of the trainee by a licensed operator. As a corrective action, the Operations Superintendent issued letters to all licensed operators and trainees stressing each individual's responsibility for control room trainees. The requirements in the letters were also incorporated into Operations Head Instruction (OHI) 2070, "Training."

f. (Closed) LER 50-316/91009-LL: Inoperable Ice Condenser Due To Incorrect Flow Passage Inspections

The licensee's engineering evaluation revealed that the ice condenser flow passage inspection to satisfy Technical Specification Surveillance requirements did not include the entire flow as assumed in the short term containment integrity analyses presented in the Updated Final Analysis. Since the flow area assumed in the containment integrity analysis was not fully

inspected, the potential existed for an unacceptable degradation of the flow area.

The licensee revised the "Inspection of Ice Condenser Flow Passages," surveillance procedure, **12 EHP 4030 STP.250, Revision 0, November 12, 1991, to include the new inspection areas. The ice condenser flow passages inspection in both units were completed and found to be operable prior to expiration of the TS LCO time limit.

One inspector followup item and no violations, deviations, or unresolved items were identified.

6. Actions on Previously Identified Items (92701)

a. (Closed) Open Item 50-316/91027-04: Loss of Turbine Driven Auxiliary Feed Water Pump (TDAFWP) Flow Retention Due To Inaccurate Flow Measurements.

The licensee's continuing investigation into the root cause of the TDAFW pump flow retention element inaccuracy found that the smaller orifice at the pump discharge did not have an effect on the measurement inaccuracy between the pump discharge and test line flows. The test results indicated that the smaller diameter orifice, while reducing the magnitude of the flow error, did not completely correct it. As a result, the licensee is continuing with actions to identify the cause for the flow measurement inaccuracy. The licensee plans to relocate the orifice further downstream in a long straight run of pipe, away from bends and other components which might have an effect on the flow readings at the orifice. Installation of this modification, RFC-4126, is planned for 1993-1994 refueling outage. The licensee's completion of investigation and correction for the root cause of the flow retention element inaccuracy will be an inspector followup item (Item 50-316/92018-03).

b. (Closed) Open Item 50-316/92009-02: Degradation of Divider Seal Located Between Containment Wall and Crane Wall.

The inspector's review of LER 50-316/90008, "Degradation of Divider Barrier Seal Located Between Containment Wall and Crane Wall," found that divider barrier seal degradation of the type identified in the LER would remain undetected using the existing surveillance procedure. The licensee has since issued a new "Containment Divider Barrier Seal," surveillance procedure **12 EHP 4030 STP.249, Revision 0, July 1, 1992, to require removal of two one-foot sections or "coupons" for testing purposes every 18 months. After reviewing the new surveillance procedure, the inspector concluded that the removal and testing of the divider seal barrier coupons should allow for detection of divider barrier seal degradation in areas not normally visible for inspection. Based on the revised surveillance procedure, this item is closed.

One inspector followup item and no violations, deviations, or unresolved items were identified.

7. Outages (37700, 61726, 62703)

Some of the major work accomplished during the Unit 1 refueling outage included eddy current testing and plugging/sleeving of steam generator tubes, reactor coolant pump seal replacements, extensive erosion/corrosion inspection of turbine steam piping, refurbishment of all four main steam stop valves, modification to the auxiliary feedwater emergency leakoff valves, repair to the high pressure turbine casing, low pressure turbine refurbishment, and satisfactory completion of containment integrated leak rate test.

No violations, deviations, unresolved, or inspector followup items were identified.

8. Inspector Followup Items

Inspector Followup Items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Inspector followup items disclosed during the inspection are discussed in Paragraph(s) 5.d. and 6.a.

9. Unresolved Items

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An Unresolved Item disclosed during the inspection is discussed in Paragraph 3.c.

10. Management Meeting

A management meeting, attended as indicated in paragraph 1.a., was conducted at the plant site on October 22, 1992. The purpose of the meeting was to discuss information relative to Unit 2 turbine generator repair/modification status, Unit 1 steam generator inspection and repair, the life cycle assurance program, and plant and engineering initiatives.

11. Management Interview

The inspectors met with licensee representatives as identified in paragraph 1 of this report on October 30, 1992, 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 or processes as proprietary.