U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/92022(DRP); 50-316/92022(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: December 3, 1992, through December 18, 1992

Inspectors: J. A. Isom

D. J. Hartland

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

12/31/92
Date

Inspection Summary: Inspection from December 3 through 18, 1992 (Report Nos. 50-315/92022(DRP); 50-0316/92022(DRP)).

Areas Inspected: Special safety inspection by the resident inspectors of Unit 2 emergency diesel generator trip on September 28, 1992, and Unit 2 operation in Mode 2 with expired steam generator stop valve surveillance on November 22, 1992. Three apparent violations were identified relating to failure to maintain an emergency diesel generator OPERABLE as required, failure to provide appropriate procedural acceptance criteria, and failure to correct an adverse condition relating to the diesel generator. These items are detailed in paragraph 2.b.

DETAILS

1. Persons Contacted

* 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
* J. M. Kauffman, Construction Manager
  T. P. Beilman, Maintenance Superintendent
* T. K. Postlewait, Design Changes Superintendent
* J. R. Sampson, Operations Superintendent
* P. G. Schoepf, Project Engineering Superintendent
* J. S. Wiebe, Safety & Assessment Superintendent
* M. E. Barfelz, Safety and Assessment Supervisor
* J. B. Kingseed, AEPSC Nuclear Safety Manager
  L. H. Vanginhoven, Site Design Superintendent
* G. A. Weber, Plant Engineering Superintendent

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 Interviews on December 21 or 23, 1992.

2. Unit 2 "AB" Emergency Diesel Generator (EDG) Low Lube Oil Pressure Trip

a. Description of Event

On September 28, 1992, 24 seconds after starting the Unit 2 "AB" EDG for performance of the Technical Specifications (TS) monthly surveillance, the EDG tripped on low lube oil pressure. The licensee subsequently discovered that the remote lube oil tank level indicator, located in the EDG sump pit, was reading 42 percent full, or the equivalent of 309 gallons. This was below the licensee administrative low limit of 400 gallons. The actual amount of oil in the tank, as measured by a dipstick, was only 127 gallons. In addition, a low level alarm, independent from the level indicator, should have come in at 50 percent (383 gallons). This alarm was never received. As followup to the event, the inspector identified a concern related to the failure of operations personnel to identify that the level indication had fallen below the licensee administrative limit. Additionally, the inspector performed a detailed investigation into this event in order to determine whether the Unit 2 "AB" EDG had become inoperable for a period of time in excess of that allowed by Technical Specifications (TS).

b. Event Root Causes

Diesel generator 2AB had a small chronic lubricating oil leak which continued uncorrected over a period of several months until oil level fell too low to sustain diesel operation. Weekly monitoring of the level utilized an inaccurate gauge and did not result in detection and correction of the adverse trend. Also, an installed level alarm failed to annunciate a low level condition in the tank. Thus, operations, engineering, and maintenance factors all contributed to the diesel operability.

Based on review of licensee work request and surveillance records and interviews with key personnel, the inspector determined that the failure of licensee personnel to identify the low lube oil level was primarily caused by a lack of acceptance criteria in the licensee's surveillance procedures. In addition, the licensee failed to take action to repair a leak on the Before and After Pump, which was the source of the loss of lube oil inventory.

1) Lack of Procedural Acceptance Criteria

Test No. 73A of Attachment No. 2 of "Preventative Maintenance and Performance Monitoring Surveillance Testing for Non- Technical Specification Equipment," OHI 5030, Revision 10, April 19, 1990, required that the EDG lube oil level indicator be read once a week by an auxiliary equipment operator. The operator was required to obtain the level reading from the indicator in the EDG sump pit. Because the indication read in percent level, the operator was then required to refer to the Tech Data Book to convert the reading 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 since May 1992. Recorded level 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. The inspector noted that OHI 5030 did not contain any minimum acceptance criteria for the lube oil volume.

2) Failure to Take Corrective Action

The inspector noted that the decreasing lube oil level was caused by a leak from the Before and After pump. The primary function of this pump was to maintain engine lubrication while in standby. Although a work request was written to repair the pump seal on May 9, 1992, the repair work had not yet been initiated at the time of the event. The work request did not quantify the leak, and the licensee assigned the request a low work priority without evaluating the significance of the leak.

In addition, a plant Environmental Chemistry Engineer documented a concern in an electronic mail (E-mail) message to plant management on June 12, 1992, related to the routing of the leaking oil to an adjacent floor drain. The oil eventually ended up in the Unit 2 Transformer Deck Catch Basin, which was designed to be used in the event of an accidental spill, rather than for routine collection. In the E-mail message, the pump leak rate was documented as being 1 pint per hour, or the equivalent of 3 gallons per day.

3) Contributing Factors

The licensee determined that the inaccurate level indication was due to the presence of air in the sensing line. The licensee has subsequently demonstrated that air was entering the line while drawing oil samples. The sample point was located at a slightly lower elevation than the level gauge on the same pipe, allowing air to enter the line when the sample valve was opened.

During the investigation into the event, the licensee determined that the lube oil level readings obtained by the operators were inaccurate and the level error was non-conservative. The licensee determined that the level gauge indicated about 182 gallons higher than the actual volume in the tank.

The licensee could not determine a definitive root cause for the failure of the low level alarm to actuate. During diagnostic testing, however, they noted that the alarm operated intermittently, suggesting that some foreign matter may have been in the pivots of the alarm switch.

A review of the initial modification package revealed that it did not include adequate as-installed-post-modification testing. No actual verification of proper operation versus dip stick levels was performed. Additionally, this would have been an opportunity to discover the improper geometry that allows air to be introduced into the level gauge piping.

c. EDG Operability Evaluation

The low-low lube oil supply pressure trip occurred because oil supply to the shaft driven lube oil pump was interrupted. There was a 20 second time delay relay in the lube oil pressure trip circuit which would allow the pump to come up to speed and establish normal operating pressure after the EDG was started. The low lube oil pressure trip actuated, as designed, to shut down the EDG because the lube oil pressure failed to reach normal required pressure. The operation of the pump, which occurred

automatically as the engine began to roll, lowered the oil level down to the point of uncovering the suction check ("foot") valve in the suction piping within the lube oil tank. The inspector learned through discussions with the EDG system engineer that the lube oil level in the tank decreases after the EDG starts to provide extra oil to the engine.

The foot valve was located about 10.5" above the bottom of the tank, which corresponded to a volume of approximately 130 gallons required to maintain suction to the oil pump.

Although the licensee was unable to conclude when the lube oil inventory reached the point where the EDG was unable to perform its designed safety function, the licensee determined that a lube oil inventory of at least 211 gallons would be sufficient to maintain short-term EDG operability. This conclusion was based on the last monthly surveillance test which was performed successfully on the Unit 2 "AB" EDG on September 1, 1992. The licensee calculated that there were approximately 211 gallons in the tank at that time. This figure was derived from a volume of 127 gallons measured on September 28, compensated for by a fairly constant 3 gallon per day oil loss as determined by review of level indicator readings taken over several weeks prior to the event.

The inspector concluded that the EDG was rendered inoperable when the oil level reached the point where the foot valve would have become uncovered after an EDG start and subsequent oil level draw down. The inspector determined a typical draw down volume from data taken by the licensee during a routine monthly surveillance run on the Unit 1 CD EDG conducted on December 2, 1992, which was witnessed by the inspector. The licensee measured the lube oil level before and during the run, and the inspector determined 56 gallons to be the oil draw down volume. Adding this figure to the minimum 130 gallon oil volume required to cover the foot valve, a minimum of 186 gallons of inventory is required to maintain EDG operability. Using the 3 gallon a day leak rate, the <u>EDG became inoperable, on or about September 10, 1992, 18 days prior to the event</u>.

d. <u>Statement of Apparent Violations</u>

1) Unit 2 TS 3.8.1.1 requires that both EDGs be operable for unit operation in Modes 1 through 4. With one EDG inoperable, the inoperable EDG is required to be restored to an operable status within 72 hours or the unit must be put in Hot Standby within 6 hours and Cold Shutdown within the following 30 hours.

Contrary to the above, the licensee operated Unit 2 in Modes 3 and 4, on September 10 through 25, 1992, during which time Unit 2 "AB" EDG was in an inoperable condition for a period in excess of 108 hours, but the unit was not placed in cold shutdown.

The failure to maintain both EDGs operable for unit operation in MODES 1 through 4 is an apparent violation of TS 3.8.1.1 (Violation 50-316/92022-01).

2) 10 CFR Part 50, Appendix B, Criterion V., states, in part, that "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances...". In addition, "instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished."

Contrary to the above, Test No. 73A of Attachment No. 2 of licensee procedure "Preventative Maintenance And Performance Monitoring Surveillance Testing For Non Technical Specification Equipment," OHI 5030, Revision 10, April 19, 1990, which monitored the lube oil inventory, did not include acceptance criteria for EDG lube oil level. This contributed to oil inventory falling below the level required to maintain EDG operability.

The failure to include acceptance criteria for EDG lube oil level is an apparent violation of 10 CFR Part 50, Appendix B, Criterion V (Violation 50-316/92022-02).

3) 10 CFR Part 50, Appendix B, Criterion XVI, states, in part, that "measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected."

Contrary to the above, the licensee failed to take action to repair a Unit 2 "AB" EDG Before and After Pump seal leak, which was identified as early as May 1992. This contributed to the lube oil inventory falling below the volume required to maintain EDG inoperability.

The failure to promptly identify and correct the Unit 2 "AB" EDG Before and After Pump seal leak is an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI (Violation 50-316/92022-03).

e. Licensee Corrective Action

As immediate corrective action, the licensee was monitoring EDG lube oil level on a daily basis using a dipstick until a reliable alternative was established. The licensee also revised the log sheet to include the minimum required level.

Long-term corrective actions, as documented in LER 316/92008, include:

* review of the operations' tour/surveillance procedures and data review process to identify and resolve problems in recognizing and responding to adverse trends

* engineering review of the lube oil level indication design

* review of the work request process for possible enhancements to the prioritization system

Three apparent violations were identified in this area, which are being considered for escalated enforcement. No deviations, unresolved, or inspector followup items were identified.

3. Operating in Mode 2 with Expired SG Stop Valve Surveillance:

a. Background:

D. C. Cook Unit 2 started up late on November 21, 1992. This was the first startup after receiving the generator rotor back from the vendor facility, where it had been shipped for inspection and balancing to correct excessive vibration which had been observed on the turbine generator during startup and parallel operations. The licensee had completed a 116 day refueling outage on June 16, 1992, and had been actively investigating the turbine vibration problems since June 20, 1992. Because of the excessive vibration on the turbine generator, the licensee had been unable to maintain the generator paralleled to the grid for any length of time.

At 12:21 a.m. on November 22, 1992, the licensee declared an unusual event when the shift supervisor determined that only one steam generator (SG) stop valve was allowed to be inoperable in MODE 2. The plant was operating in MODE 2 without current surveillance testing on any of the four stop valves. The operators commenced a reactor shutdown, and the licensee exited the unusual event at 12:32 a.m. when the Unit was placed in MODE 3. Although all SG stop valves were closed for the time that Unit 2 was in MODE 2, the shift supervisor considered all SG stop valves inoperable because surveillance on all of the SG stop valves had expired.

b. Technical Specifications (TS) Requirement:

Section 3.7.1.5 of Unit 2 TS require that each SG stop valve shall be OPERABLE in MODES 1, 2, and 3. If not, the ACTION statement requires that with one SG stop valve inoperable, subsequent operation in MODES 2 or 3 is allowed if the SG stop valve is maintained closed. In addition, with one SG stop valve inoperable, the TS allow the Unit to change from MODE 3 to MODE 2 providing the inoperable SG stop valve is maintained closed. Otherwise, the Unit must be placed in MODE 4, or HOT SHUTDOWN within the next 12 hours. Also, the TS allow the licensee to enter into MODE 2 when performing PHYSICS TESTS at the beginning of a cycle provided that all steam generator stop valves are maintained closed.

The inspector reviewed the operations department surveillances, logs, and records, interviewed various members of the licensee's staff, and initially concluded that the licensee had violated the TS requirement to have each SG stop valve operable in MODE 2 by entering MODE 2 with an expired SG stop valve surveillance. These surveillances, "Steam Generator Stop Valve Operability Test" **2-OHP 4030.STP.019F, Revision 1, June 11, 1992, verify that the SG stop valves are able to meet the closure time of eight seconds which is specified in Section 4.7.1.5.1 of the TS.

The last surveillances for the stop valves were performed June 13, 1992, for MRV-210, 220, and 240. The last surveillance on MRV-230 was completed on June 17, 1992. These SG full stroke surveillances are required to be performed by Section IWV-3412(a) of the American Society of Mechanical Engineers (ASME) Code, during each shutdown period, if the interval between shutdowns is greater than 92 days. In this case, the inspector calculated that the 92 day time period ended on September 16, 1992. The inspector used the end of the refueling outage on June 16, 1992, as the beginning of the 92 day time period to make this calculation.

Additionally, the inspector reviewed the licensee's completed "Zero Power and Power Ascension Tests for Post Refueling Startup," **2 EHP 6040 PER.359, Revision 0, June 8, 1992, and determined that all of the low power physics tests had been completed at the time of Unit 2 startup from the refueling outage in June of 1992. Therefore, TS 4.7.1.5.3 which allows entry into MODE 2 for physics testing was not applicable for the November 21, 1992, startup.

c. Safety Significance:

The Unit 2 entry into MODE 2 with an expired surveillance test was of minimal safety significance based on the following:

1) Surveillance Results:

The inspector reviewed the surveillances performed on the SG stop valves bracketing the time period Unit 2 was in MODE 2 with an expired surveillance. The inspector's review of the surveillances performed on the SG stop valves on June 13 through 17, 1992, and on November 30, 1992, verified that all SG stop valves satisfied the closure requirements of the TS. Based on these surveillances, the inspector concluded that the SG stop valves would have satisfactorily performed their safety function if called upon.

2) Status of the SG Stop Valves:

The inspector noted that during the entire period in which Unit 2 was operated in MODE 2 with expired surveillances, all SG stop valves were closed. Also, the licensee had placed red tags for equipment and personnel protection on the stop valves thereby placing an additional administrative control on the ability to open these valves.

3) Duration:

The inspector noted through review of the control room logs that the duration of Unit 2 operation in MODE 2 was short. Unit 2 was operated in MODE 2 for about four hours before the surveillance problem was identified and actions taken to return the Unit to MODE 3.

d. Corrective Actions:

Once the shift supervisor determined that transition to MODE 2 was not allowed with more than one SG stop valve not demonstrated operable, he took immediate actions to place the Unit in MODE 3 where the Unit could operate with expired SG stop valve surveillances. The shift supervisor made this determination at 11:30 p.m. on November 21, 1992, and commenced reactor shutdown at 12:21 a.m. on November 22, 1992. Unit was in MODE 3 at 12:32 a.m. on November 22, 1992. The inspector concluded that the strong positive actions exhibited by the shift supervisor was a strength. Also, the support for his decision to shut down the Unit despite prior management approval for the MODE change was a strength in the licensee's shift organization and management support of that shift organization. In the event that the shift supervisor had not shut down the Unit to MODE 3, the inspector noted that the "Reactor Startup Procedure," **2-OHP 4021.001.002, Revision 15, November 17, 1992, would have required the operators to equalize and open all SG stop valves in the next few steps. The inspector concluded that the shift supervisor actions prevented a situation in which the operators were required to open the stop valves with

expired surveillances later in the startup. The licensee successfully completed the surveillances on all SG stop valves on November 30, 1992, before Unit 2 was placed in MODE 2.

Further review of ASME Code IWV-3416 reveals that: "For a valve in a system declared inoperable or not required to be operable, the exercising test schedule need not be followed. Within 30 days prior to return of the system to operable status, the valves shall be exercised and the schedule resumed in accordance with requirements of this article."

Based on the main steam system being out of service to facilitate work on the main generator, this article applies to the periodicity of the surveillance test and there was no violation of TS. If the shift supervisor had not decided to shut down to MODE 3 until the surveillances were performed, the unit would have been in MODE 2 without stroke-time testing four main steam stops as soon as either a main steam stop was opened or the main steam system was required to be operable.

4. Conclusion:

The inspector concluded that the Unit 2 EDG became inoperable approximately 18 days before it failed during testing on September 28, 1992. Consequently, the licensee appeared to have violated the requirements for EDG operability stated in TS 3.8.1.1 for a time period greater than allowed by the applicable LCO. This problem occurred because the licensee failed to detect and correct a potentially adverse lube oil tank level condition until the EDG tripped.

The inspector determined that, in retrospect, the SG stop valves were not opened during the time Unit 2 was in MODE 2 on November 21 and 22, 1992. Since the licensee did go to MODE 3 and perform the required surveillance prior to opening a SG stop valve in MODE 2, no violation of TS occurred.

5. Management Interview

The inspectors met with licensee representatives denoted in paragraph 1 on December 21, 1992, to discuss the scope and findings of the inspection. A followup meeting was conducted on December 23, 1992, to further discuss certain aspects of the findings. The second meeting clarified the number and nature of the enforcement findings as a result of an Enforcement Board meeting held on December 21, 1992. 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.