U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/94009(DRP); 50-316/94009(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: April 23 through June 3, 1994

Inspectors: J. A. Isom
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Reactor Projects Section 2A

Inspection Summary:

Inspection from April 23, 1994, through June 3, 1994
(Report Nos. 50-315/94009(DRP);50-316/94009(DRP))

Areas Inspected: Routine, unannounced safety inspection by resident and regional inspectors of action on previous inspection findings; operational safety verification; current material condition; housekeeping and plant cleanliness; radiological controls; security; safety assessment/quality verification; maintenance activities; surveillance activities; MOV testing; reactor coolant pump vibration; and analog to digital instrumentation replacement.

Results: Of the twelve areas inspected, one violation was identified that pertained to MOV testing (paragraph 6.a). One non-cited violation was identified that pertained to AFW valve positioning (paragraph 3.a). Two Unresolved Items were also identified that pertained to maintenance (paragraph 5.a.2) and containment housekeeping (paragraph 3.c).

The following is a summary of the licensee's performance during this inspection period:

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PDR ADOCK 05000315
Q PDR

Plant Operations:

Licensee performance in this area was adequate. The licensee improved the RCS draindown procedure. However, the inspectors identified some mispositioned AFW pump bearing cooling valves and a concern with the inspection of the containment prior to entering Mode 3.

Maintenance and Surveillance:

The licensee performance in this area was adequate. The licensee's PM program did not include an inspection of some non-safety 4kv cables. However, once damage to one of these cables was identified, the repair was of high quality. Technicians performing MOV testing responded well to difficulties encountered during testing. The inspectors identified a concern with a pitted valve stem on a main steam stop valve dump test valve that resulted in the licensee entering a four hour LCO four times since 1992 to replace the valve's packing. This issue will be reviewed further by the NRC in a future inspection.

Engineering and Technical Support:

The licensee's performance in this area was adequate. The licensee had not aggressively pursued validation of assumptions in the motor-operated valve program. However, the identification and troubleshooting of an electrical noise in the new reactor protection system equipment was considered good.

DETAILS

1. Persons Contacted

A. A. Blind, Plant Manager
*K. R. Baker, Assistant Plant Manager-Production
*L. S. Gibson, Assistant Plant Manager-Technical
*J. E. Rutkowski, Assistant Plant Manager, Support
R. K. Gillespie, Executive Staff Assistant
D. C. Loope, Executive Staff Assistant
*T. P. Beilman, Maintenance Superintendent
P. F. Carteaux, Training Superintendent
*D. L. Noble, Radiation Protection Superintendent
L. J. Matthias, Administrative Superintendent
T. K. Postlewait, Design Changes Superintendent
*J. S. Wiebe, Quality Assurance and Control Superintendent
*R. W. Hennen, Plant Engineering Superintendent(Acting)

*Denotes those attending the exit interview conducted on June 3, 1994.

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

2. Action on Previous Inspection Findings (92701)

a. (Closed) Violation 50-315/93016-02: Inoperable EDG due to failure to perform a safety evaluation.

The licensee failed to perform a safety evaluation prior to de-energizing the emergency diesel generator room ventilation damper in the open position. The open damper position caused excessive room cooling that contributed to the trip of the Unit 1 "AB" diesel generator during a surveillance test. The licensee added a caution to paragraph 5.4.3 of "Temporary Modification" procedure, PMP 5040 MOD.001, that stated pulling fuses to fail open the diesel generator room ventilation damper could result in diesel system degradation from excessive room cooling.

b. (Closed) Violation 50-316/93016-01: Degraded motor-driven auxiliary feedwater pump due to failure to repair pump packing leak.

The licensee's failure to repair a minor auxiliary feedwater pump packing leak in a reasonable time lead to a condition where water intruded into the outer bearing housing. This condition caused water contamination of the oil in the housing and lead to damage to the bearings and pump internals. As corrective actions to prevent recurrence of the problem, the licensee:

- established a plant wide oil analysis program
- reviewed the pump sealing arrangement
- provided written guidance to the operators

c. <u>(Closed) Violation 50-316/93018-03:</u> Inadequate procedure for installing pump thrust bearings.

The maintenance procedure lacked the specificity required to install the auxiliary feedwater thrust bearings correctly. This caused accelerated bearing wear. The licensee revised procedure, "Motor Driven Auxiliary Feed Pump Maintenance," **12-MHP 5021.056.001, with a note to install bearings in the proper back-to-back configuration with reference to a diagram in the procedure that showed this configuration.

d. <u>(Closed) Violation 50-315/93018-02; 50-316/93018-02:</u> No inspection sign-offs sheet verifying tightening of conoseal.

There was no inspection hold points for conoseal installation. The conoseals were a reactor pressure boundary and the lack of inspection hold points could lead to the seals being improperly installed. The licensee determined that the inspection sign-offs were removed during the procedure's revision process. Procedure "Reactor Reassembly," **01-OHP 4050.FHP.004 for Unit 1 was revised to include inspection holdpoints when reassembling the conoseal assemblies. No revision was required for the Unit 2 procedure since the procedure contained quality control inspection steps.

e. <u>(Closed) Violation 50-316/93020-01:</u> Failure to correct deficient turbine-driven auxiliary feedwater pump trip and throttle valve condition.

Operators failed to recognize that repeated attempts to open the trip and throttle valve constituted a valve failure under the ASME Code Section XI. This resulted in the operator not declaring the trip and throttle valve inoperable during a surveillance when several attempts were made to meet the stroke time requirement under the ISI program. The licensee revised Operational Standing Order 74 to require that the turbine-driven auxiliary feedwater pump be declared inoperable if the trip and throttle valve failed to pass the first valve stroke test.

f. <u>(Closed) Unresolved Item 50-315/94002-07:</u> Unexpected closure of hot leg suction valve to the RHR pump.

The inspectors reviewed the licensee's root cause and corrective action documented in Condition Report 94-304 for this operational event. The licensee determined that the valve went shut because the closure permissive bi-stable was deenergized. The bi-stable was de-energized because the protection set II channel was turned off for a planned reactor protection system modification.

Therefore, when the electrical power was restored to valve ICM-129, the valve went closed. The licensee was planning to incorporate experiences learned from the Unit 1 outage so that similar problems can be prevented during the reactor protection system modification for Unit 2. This review is planned to be held in June of 1994.

g. <u>(Closed) Inspection Follow-up Item 50-315/92020-01:</u> Failure to implement LER corrective actions.

The inspectors were concerned that the licensee had not adequately addressed instrumentation and control (I&C) department work control processes that contributed to the Unit 2 trip on November 15, 1991. As a result of the reactor trip on February 21, 1994 caused by an I&C work activity, the licensee evaluated the I&C involvement in trip events and trip event precursors since 1990. This study concluded that the I&C's overall performance has shown improvement and I&C involvement in trip event precursors has decreased over the past 4 years. The inspectors have no further questions in this matter.

h. <u>(Closed) Inspection Follow-up Item 50-315/93011-01;50-316/93011-01:</u> Potential safety relief valve discharge on Appendix R emergency lighting.

The inspectors identified that component cooling water safety relief valves discharged above Appendix R emergency lights. The inspectors learned that the addition of an emergency light unit for Unit 1 and a modification performed to the safety valve discharge piping to address possible lift inaccuracy problems for Unit 2 caused the emergency lights to be near the general vicinity of the discharge from the safety valves. The licensee has since hard-piped the discharges to the floor drain and wrote a memorandum to the project engineering group of the subtle effect of one modification causing problems for already installed equipment.

i. <u>(Closed) Inspection Follow-up Item 50-315/93011-02; 50-316/93011-02:</u> Consequences of potential failure of Appendix R emergency lighting.

The inspectors discussed the potential loss of Appendix R emergency lights on the ability of the operators to safely shutdown the unit and found that the safety consequences from loss of these lights to be small. These lights provide general area lighting of some essential service and component cooling water valves that may require local operation during an appendix R shutdown.

3. Plant Operations

At the beginning of the inspection period, Unit 1 was in Mode 5 for the completion of the cycle 13-14 refueling outage. After entering Mode 3, the licensee discovered leakage from canopy welds on the core exit thermocouple seal assemblies. Unit 1 was placed in Mode 5 and the leaks were repaired. On May 30, 1994, at 3:57 pm, Unit 1 was paralleled to the grid and has since operated up to 70 percent power.

At the beginning of the inspection period, Unit 2 was at approximately 7 percent power, following an extended forced outage for replacement of the main generator rotor. Unit 2 was paralleled to the grid at 10:28 pm, on April 24, 1994, and has since operated up to 100 percent power.

On May 26, 1994, due to the extended Unit 2 operating cycle, the licensee was granted a notice of enforcement discretion (NOED) with regards to compliance with the requirements of paragraph 4.6.1.2.d of Technical Specification (TS). This paragraph required that Type B and C leak rate tests be performed at an interval no greater than 24 months. The NOED was in effect until a TS amendment was issued on June 1, 1994.

a. Operational Safety Verification (71707)

The inspectors verified that the facility was being operated in conformance with the licenses and regulatory requirements, and that the licensee's management control system was effective in ensuring safe operation of the plant.

On a sampling basis the inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored control room indications for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station management. The inspectors reviewed applicable logs and conducted discussions with control room operators throughout the inspection period. The inspectors observed a number of control room shift turnovers. The turnovers were conducted in a professional manner and included log reviews, panel walkdowns, discussions of maintenance and surveillance activities in progress or planned, and associated LCO time restraints, as applicable. The inspectors had the following observations:

- The inspectors have been concerned with the licensee's control of non-essential service water (NESW) inlet and outlet valves to the Auxiliary Feedwater AFW pump bearings. Two examples were identified and discussed previously in Inspection Report No. 50-315/94005(DRP); 50-316/94005(DRP) that pertained to when NESW cooling water should be supplied to a running AFW pump.

On May 3, 1994, the inspectors observed a third example during a routine tour of the Unit 2 AFW pump areas. The inspectors noted that the NESW outlet valves for each of the pumps' bearings were open. The unit was in Mode 1 and the pumps were in standby at that time. Licensee procedure "Filling and Venting the AFW System and Placing System in Standby Readiness," 02OHP4021.056.001, Revision 10 requires that these valves be closed. Having these valves in the open position is a violation of procedure 02OHP4021.056.001 and Technical Specification 6.8.1. However, this violation is of minimal safety significance and is not being cited because the criteria specified in Section VII.b(1) of the Enforcement Policy were satisfied.

The inspector informed the Shift Supervisor of this condition. The valves were closed and CR# 94-0945 was initiated to document the deficiency.

- On April 26, 1994, the inspectors observed the Unit 1 RCS draindown to approximately 2 feet below reactor flange level to support the replacement of the RCP #13 motor. The inspectors observed that the evolution was well-planned and coordinated. The inspectors reviewed the procedural and process changes implemented due to problems encountered during a previous draindown evolution as documented in Inspection Report 50-315/94004(DRP). The inspectors noted the following:

1) A wide-wide range level instrument, NLI-132, was installed to provide indication from about middle of the pressurizer to the mid-loop area. The inspectors observed that NLI-132 provided accurate indication of the RCS level throughout the evolution.

2) The licensee also revised procedure, "RCS Draining," 01-OHP4021.002.005, to require that draining operations be stopped if discrepancies between NLI-132 and other level indicators were identified. The procedure also contained a table that correlated the level instrument, NLI-132, to other level indicators to determine whether a discrepancy existed between the level instruments.

3) Procedure 01-OHP4021.002.005 also required the operators to record the expected volume of water to be drained from the RCS and the initial level in the tank that collected the RCS water. The inspectors noted that this information would be more useful if the procedure provided a method to convert the percent

tank level change to a volume measurement so the operators could validate the initial estimate of the draindown volume.

4) The licensee prepared plant drawing #1-5663-0, "Unit 1 RCS Loop Details," to provide a correlation between level indication readings and plant reference elevations.

5) The licensee conducted a special training session for all shifts to address the enhancements made to the draining process. The training included a discussion of the proper way to depressurize the RCS to minimize level perturbations. The operators conducted pre-job briefings for each shift involved in the draindown evolution. The licensee also added a sign-off to the procedure to verify the performance of a shift briefing prior to the start of the draindown. Although the procedure did not require senior plant management participation and required briefings only to subsequent shifts assuming duties for a unit entering or operating at "reduced RCS inventory," discussion with the operations management indicated that such briefs would be conducted for each of the shifts conducting the draindown evolution.

b. Current Material Condition (71707)

The inspectors performed general plant as well as selected system and component walkdowns to assess the general and specific material condition of the plant, to verify that work requests had been initiated for identified equipment problems, and to evaluate housekeeping. Walkdowns included an assessment of the buildings, components, and systems for proper identification and tagging, accessibility, fire and security door integrity, scaffolding, radiological controls, and any unusual conditions. Unusual conditions included but were not limited to water, oil, or other liquids on the floor or equipment; indications of leakage through ceiling, walls or floors; loose insulation; corrosion; excessive noise; unusual temperatures; and abnormal ventilation and lighting.

During plant tours, the inspectors noted the following:

- The charge light on the following three emergency light units were not flickering which could be indicative of a problem with an internal charger:

1-BATLIT-191:	Auxiliary Feedwater Pump Hallway
1-BATLIT-10:	Unit 1 4KV electrical room
1-BATLIT-356:	Unit 1 "W" RHR room

The inspectors discussed this concern with the electrical maintenance engineer. The engineer verified that all three units were functioning satisfactorily and did not need repair. The aim for one emergency battery light in the Unit 1 "W" RHR room was corrected.

- During a Unit 1 control room tour on May 6, 1994, the inspectors noted an alarm for high tailpipe temperature for pressurizer safety valves. Because the inspectors were concerned that this was an indication of a leaking pressurizer safety valve, the inspectors contacted the onsite valve engineer. The inspectors were informed that one of the pressurizer safety valves, 1-SV-45B, had been leaking slightly but the leak was stopped by halting the reactor heatup. The engineer believed that the leak was caused by the heatup of the pressurizer that caused a temperature gradient across the valve seating surface. This temperature gradient caused some temporary seat deformation and slight leakage. The condition was corrected through halting the primary plant heatup and allowing the valve to reach thermal equilibrium.

  Additionally, the engineer determined that the pressurizer safety valve, 1-SV-45C, high tailpipe temperature alarm observed during startup on May 26, 1994, was because of the high ambient temperature condition in the pressurizer "doghouse" in combination with too low an alarm setpoint. The inspectors review of the pressurizer "doghouse" temperature and the alarm setpoint confirmed that the safety valve was not leaking.

c. Housekeeping and Plant Cleanliness

The inspectors monitored the status of housekeeping and plant cleanliness for fire protection and protection of safety-related equipment from intrusion of foreign matter.

On May 8, 1994, the inspectors toured Unit 1 containment after the licensee's closeout inspection of containment performed on May 2, 1994, using procedure 01-OHP.4030.001.002, Revision 12, "Containment Inspection Tour." The inspectors had the following observations:

- several minor valve leaks
- red and grey tape on the missile wall and the control rod drive ventilation piping
- ear plugs, allen wrench, bolt, nut and washer, etc., on the lower containment basement floor.

The extraneous items were subsequently removed from the containment by the licensee. However, the inspectors were concerned that extraneous items were found on the containment basement floor after inspection of the containment by the licensee per Technical Specification (TS) surveillance requirement 4.5.2.c. This TS surveillance requires a visual inspection to verify that no loose debris would be present in the containment which could be transported to the containment sump and cause restriction during a LOCA. Previously poor housekeeping in the containment during the outage was addressed in Inspection Report 50-315/94005(DRP);50-316/94005(DRP). This matter is considered an Unresolved Item pending further review by the NRC (50-315/94009-01(DRP)).

On May 26, 1994, after the licensee had made repairs to the conoseal assemblies, the inspectors made another tour of Unit 1 containment and noted that the housekeeping in the lower containment area had improved. The inspectors noted no visible primary leaks although some dry boric acid deposits were noted around #1, #3, and #4 reactor coolant pump (RCP) mechanical seal areas, and also on some valves. The inspectors discussed these items with the engineer in-charge of identifying material discrepancies in containment. The licensee had identified all but one valve noted as having boric acid deposit by the inspectors. This valve was entered in their job order system for repair during future outages.

d. Radiological Controls (71707)

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc. and randomly examined radiation protection instrumentation for use, operability, and calibration.

The inspectors identified an apparent hot spot in the Unit 1 charging pump room, that was not indicated on the latest survey. The radiation protection (RP) superintendent was notified. In response, the licensee verified and posted the hot spot of approximately 140 milli-rem per hour. There was no work being conducted in the room at the time, and the inspectors have not noted any recurring problems with regards to RP surveys.

e. 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.

In response to a concern regarding unsecured doors to radiation areas in the auxiliary building, the inspectors verified that Action Requests (AR) were pending to repair some unsecured doors in the auxiliary building; however, there is no safety significance to the unsecured doors, as the doors were not vital and the areas were not high radiation areas.

Also, in response to a concern that card readers on some vital area doors did not work, the inspectors verified that the licensee has a program in place to identify and repair inoperable card readers. In addition, the inspectors verified that the licensee's program included immediate compensatory actions, as required, for inoperable card readers.

The inspectors were unable to confirm a concern that a battery room door was not checked by a fire watch tour for an entire shift on about March 2-3, 1994. However, the licensee identified, during an investigation, that a fire watch did not complete required tours of the security UPS battery room on March 2. The licensee discovered that the individual had entered the UPS battery inverter room instead. No compensatory actions were required, however, as the detection system in the missed room was not required by Technical Specifications. The licensee initiated CR 94-1058 to document and investigate the discrepancy.

One non-cited violation and one unresolved item were identified. No deviations or inspection followup items were identified.

4. <u>Safety Assessment/Quality Verification</u> (40500 and 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following Licensee Event Reports were reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished, and that corrective action to prevent recurrence had been or would be accomplished in accordance with Technical Specifications (TS):

<u>(Closed) LER 316/93004:</u> Exceeded TS LCO As A Result of Inaccuracies In Control Rod Position Indication.

On April 8, 1993, the licensee entered TS 3.0.3 for approximately one hour when the position indication for two control rods in the same group were found to be reading greater than twelve steps from the demand position indication. The licensee exited TS 3.0.3 when one of the rod indications (H-12) returned to within twelve steps of demand. The licensee verified the position of the other rod (M-8) using the movable in-core detectors every eight hours, as required by TS 3.1.3.2, until that rod position indication was returned to service later that day.

The licensee attributed the problem with the rod H-12 indication to be the inherent sensitivity of the transformer located at the top of the control rod drive mechanism (CRDM) to temperature changes. The licensee found the signal conditioning module for the rod M-8 indication out-of-specification high and recalibrated it. As long-term action, due to continuing problems with the individual rod position indicators, the licensee was currently evaluating the replacement of the system with a more reliable one.

In addition to the LERs, the inspectors reviewed the licensee's condition reports (CRs) generated during the inspection period. This was done in an effort to monitor the conditions related to plant or personnel performance, potential trends, etc. CRs were also reviewed to ensure that they were generated appropriately and dispositioned in a manner consistent with the applicable procedures.

One non-cited violation was identified. No deviations, unresolved items, or inspection followup items were identified.

5. <u>Maintenance/Surveillance</u> (62703 & 61726)

<u>Maintenance Activities</u>

Routinely, station maintenance activities were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with technical specifications.

The following items were also considered during this review: limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

Portions of the following maintenance activities were observed and reviewed:

a. <u>Job Order (JO) No. C0023287</u>

While hanging ground protection for clearance support for breaker 2C6, feed to 4kv bus 2C, licensee electrical maintenance personnel discovered that cables connecting the breaker to the normal feed transformer 2CD were split open and discolored from overheating. The inspectors noted that the electricians' repair of the cable terminations was of high quality.

The licensee believed that the root cause of the damaged cables was that the cables and the lugs, which were used to connect the cables to the breaker, were made of dissimilar metals. The cable shrouds were made of aluminum, while the lugs were copper. Since the two metals expand and contract due to temperature changes at different rates, the mating surface of the cables and the lugs loosened over time. This increased the resistance in the cable and eventually resulted in an overheated condition.

As immediate corrective action, the licensee replaced the cables and replaced the lugs with aluminum ones. The licensee also inspected the cable connections on the other Unit 2 normal and reserve feed breakers and transformers. The licensee did not identify any similar conditions.

During review of JO# C0023287, the inspectors noted that the initial revision of the JO did not require that the applicable plant procedure be "in-hand", as the cables were not safety-related. This deviated from plant policy, which required that technical documents designated as "in-hand" be used by individuals during the performance of the activity. This discrepancy was also identified by site QC and documented in CR 94-0847. The JO was subsequently revised to require that the procedure be used.

As follow-up, the inspectors also noted that the licensee replaced the lugs to the Unit 1 normal feed breakers and transformers and the Unit 1 and 2 reserve feed breakers and transformers with aluminum ones in 1983 and 1984. The Unit 2 normal feed cables were not part of the modification because, apparently, the cables were in acceptable condition at that time. As long-term corrective action, the licensee intends to develop a preventive maintenance task to inspect these cables using thermographic techniques. The licensee was also evaluating expanded use of thermography for other electrical components in the plant.

b. <u>2-MMO-240 Packing</u>

During review of maintenance history, the inspectors identified that in July 1992 the licensee identified a pitted valve stem had contributed to degraded packing on 2-MMO-240. The licensee had initiated JO# C0011197 to replace the stem during the next refueling outage scheduled for August 1994. Since July 1992, the valve has been repacked 4 times without consideration for reprioritizing the stem replacement for a forced outage. The repacking of this valve required entry into a four hour Technical Specification Limiting Condition of Operation. The inspectors noted that Unit 2 had several forced outages during the cycle. This matter is considered an Unresolved Item pending further review by the NRC (50-316/94009-02(DRP)).

c. <u>Motor Operated Valve (MOV) Testing</u>

The inspectors observed portions of VOTES testing and packing adjustments on MOV 1-MCM-231, a rising rotating stem globe valve. During testing, the valve exhibited higher than expected packing loads and could not be set within the thrust window after several attempts. Also, the technicians encountered difficulties during calibration of the VOTES sensor due to the rising rotating stem arrangement. The inspectors observed that the technicians responded well to the difficulties encountered during the test and appropriately contacted the MOV coordinator for guidance. The licensee planned to repack the valve at a later date and retest. The inspectors had no concerns with this maintenance activity.

6. Surveillance Activities (61726)

During the inspection period, the inspectors observed technical specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with technical specifications and procedure requirements and were reviewed, and that any deficiencies identified during the testing were properly resolved.

The inspector reviewed licensee records, including QA/QC inspection reports and condition reports, with regards to the performance of 12EHP4030STP.211, "Ice Condenser Surveillance", during the recent Unit 1 refueling outage. The inspectors did not identify any discrepancies.

The inspectors also witnessed portions of the following surveillance:

02 OHP 4030.STP.050W, West RHR Train Operability Test

One unresolved item was identified. No violations, deviations, or inspection followup items were identified.

7. Engineering & Technical Support (37700)

The inspectors monitored engineering and technical support activities at the site including any support from the corporate office. The purpose 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.

a. MOV Testing

The inspectors reviewed three random MOV static or dynamic test packages and found one package that was returned to service without adequate evaluation. In the job order package for valve 1-QMO-226, tested May 14, 1993, the inspectors noted that the measured thrust had exceeded the allowable thrust, however, no evaluation of the condition was contained in the package.

Step 7.11.8 of procedure "MOV Diagnostic Testing - VOTES," **12IHP5030.EMP.002, Revision 1, specified that "maximum thrust is less than or equal to allowable valve/actuator maximum ratings" and Step 8, Acceptance Criteria, specified that "Thrust meets the required criteria at Running, TST, and Maximum. (If an over-thrusting condition exists, Columbus AEP Engineering must be notified.)"

The test results indicated that the measured maximum thrust was 14,721 lbs, which exceeded the specified allowable maximum rating of 12,400 lbs. Although the MOV exceeded the maximum thrust, no engineering evaluation was performed to determine acceptability. Although subsequent review found that this condition was acceptable, the inspectors were concerned with the lack of review performed to determine the acceptability of the test results. This is considered a violation of 10 CFR 50 Appendix B Criterion XI (50-315/94009-03(DRS)).

The inspectors noted two other general concerns regarding acceptance criteria used for MOV tests:

- The licensee could not demonstrate that there was sufficient margin between torque switch trip (VOTES point C14) setpoint and the torque observed at the valve at the extrapolated 100 percent flow cutoff (C10) point. Typically this setpoint includes inaccuracies to account for torque switch repeatability and the switch degradation.

- The OATIS test data was not completely evaluated to compare torque switch settings to extrapolated thrust requirements due to the limitations of the data. For MOVs tested at less than full design basis differential pressure (DP), the evaluation was necessary to determine the ability of the MOV to function at full DP.

The licensee indicated that the above inspector concern would be reviewed.

b. <u>Reactor Coolant Pump (RCP) Vibration:</u>

The inspectors reviewed the numerous "high vibration" alarms received on #23 RCP on Unit 2 to determine whether these vibrations alarms could be an indicator of degrading pump condition. Although the pump exhibited higher vibration levels as compared to the other three RCP pumps, around 15.5 to 17.0 mils, the inspectors noted no adverse pump performance problems as a result of increased vibration levels.

The inspectors' discussion with the plant engineer responsible for analyzing pump vibration found that increased vibration on #23 RCP was primarily attributable to a loose lower motor bearing. This condition has resulted in loss of some stiffness quality with the RCP that had been detected through increased vibration levels. Westinghouse engineers recommended in a 1992 analysis that the shaft alert limit be raised for the pump to 20 mils and the danger limit to 25 mils. The licensee was planning to have Westinghouse obtain confirmatory data during the Unit 2 outage planned for August 1994.

The inspectors also reviewed the operations procedure "Malfunction of a Reactor Coolant Pump," 02-OHP 4022.002.001, Revision 5, August 5, 1993, to determine whether the operations department had procedurally addressed the elevated vibrations on #23 RCP. After the initial review, the inspectors were concerned that the engineers needed to install additional instrumentation in the event that the pump vibration exceeded 20 mils. The installed instrumentation maximum reading was at 20 mils. The "OHP" required the operators to shutdown the pump at 25 mils. On May 24, 1994, the plant engineer demonstrated that the temporary instrument hookup did not require much time although there was a slight delay in the hookup because an extension cord was needed to power the unit. The operators were required to contact the plant engineering department to install the temporary vibration monitoring device when the vibration levels on an RCP reached 19 mils.

c. <u>Analog to Digital Instrumentation Replacement</u>

The inspectors reviewed 64 Design Change Deviation Requests (DCDR) pertaining to the analog-to-digital process instrumentation replacement program. One of the DCDRs written on March 3, 1994 identified that octal base relays manufactured by C. D. Clare or Potter Brumfield can produce high noise levels when de-energized.

Another DCDR written on March 3,1994 identified that during Reactor Protection System (RPS) pre and post-installation testing electrical noise was induced on the wiring on multiple occasions that caused some FOXBORO Spec 200 MICRO RPS control cards to detect a failure and revert to an "Error Standby" mode. In this mode the cards ceased to function and indicated an alarmed status locally. These RPS control cards were used to provide trip and alarm functions.

"Card Failure" alarm circuits, were unused in the D. C. Cook application. However, Foxboro connected the wiring for this circuit as an option that was accepted by the licensee. The wiring from MICRO card to MICRO card and then to a terminal block acted as an antenna and was part of a standard Foxboro design practice. The electrical noise was caused by some output relays (mentioned above) that did not have relay coil noise suppression. The noise was transmitted by test hook-up wiring and picked up by the card failure alarm circuit wiring. There would be no direct indication in the control room of a card failure, but an RPS trip or alarm would result. This design deficiency could have resulted in equipment mis-operation and subsequent unnecessary challenges to plant safety systems.

The licensee has removed the "Card Failure" alarm circuit wiring from all protection racks and added metal oxide varistors across all interfacing relay coils, 120 VAC switches, power supplies, etc. The licensee requested Foxboro to review this deficiency for reportability under 10 CFR Part 21. The inspectors were subsequently informed that Foxboro decided not to report this deficiency under 10 CFR Part 21. However, the licensee was still reviewing this deficiency for reportability under 10 CFR Part 21. The NRC will continue to monitor the licensee efforts and was evaluating the need for an Information Notice.

One violation was identified. No deviations, unresolved, or inspection followup items were identified.

8. <u>Unresolved Items</u>

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items were discussed in paragraphs 3.a and 5.a.2.

9. <u>Meetings and Other Activities</u>

<u>Exit Interview</u> (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on June 3, 1994. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.