U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/94002(DRP); 50-316/94002(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: January 19 through March 11, 1994

Inspectors: J. A. Isom

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for Reactor Projects Section 2A

4-4-94
Date

Inspection Summary:

Inspection from January 19 through March 11, 1994
(Report Nos. 50-315/94002(DRP):50-316/94002(DRP)

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of: operational safety verification; onsite event follow-up; current material condition; housekeeping and plant cleanliness; maintenance and surveillance; engineering and technical support; safety assessment; and, refueling activities.

Results: Of the eight ares inspected, one violation was identified that pertained to performing maintenance without a procedure (paragraph 3). There were eight unresolved items identified that pertained to AEO rounds (paragraph 2.a 1); AFW mini-flow (paragraph 2.b); inadvertent closure of a RHR valve (paragraph 2.b); loss pf VCT level (paragraph 2.b); emergency lighting (paragraph 2.c); work on a pressurized valve (paragraph 3); CCW temperature (paragraph 4);and Furminite calculations (paragraph 4). Also four inspection followup items were identified that pertained to lube oil fluctuations (paragraph 2.a 2); use of Condition Report (paragraph 2.a 2); operations management coverage (paragraph 2.a 2); MSSV testing (paragraph 2.b);and RCP motor bearing (paragraph 4).

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

Plant Operations:

The licensee's performance in this area was adequate. However, there were weaknesses identified with a lack of operator control of plant evolutions that resulted in unexpected system responses. These unexpected responses resulted in reactor coolant system (RCS) level being off scale for five hours during the draining of the RCS; the loss of volume control tank level during the draining of the reactor cavity, and the inadvertent closure of the residual heat removal pump suction valve from the RCS hot leg during the filling of the reactor cavity.

Maintenance and Surveillance:

The licensee's performance in this area was adequate. A weakness was identified with a instrumentation and control (I&C) maintenance evolution. A reactor trip occurred when I&C technicians did not follow a procedure for maintenance on a main steam isolation dump valve. The performance of I&C technicians during maintenance activities was a concern in a previous inspection report. I&C maintenance has been involved either directly or indirectly in most of the recent reactor trips for Units 1 and 2.

Engineering and Technical Support:

The licensee's performance in this area was adequate. There were concerns identified that pertained to; the decision to discontinue monitoring of a resistance temperature detector for the Unit 1 reactor coolant pump motor radial bearing without adequate engineering justification; the licensee's failure to effectively communicate the new environmental qualification (EQ) requirements to the electricians for electrical splices on EQ components; and the adequacy of calculations for the furmanite process used on a safety-related valves in containment.

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
*T. P. Beilman, Maintenance Superintendent
P. F. Carteaux, Training Superintendent
*D. L. Noble, Radiation Protection Superintendent
*T. K. Postlewait, Design Changes Superintendent
*S. A. Richardson, Operations Superintendent
P. G. Schoepf, Project Engineering Superintendent
*J. S. Wiebe, Safety & Assessment Superintendent
*L. H. Vanginhoven, Site Design Superintendent
*G. A. Weber, Plant Engineering Superintendent

*Denotes those attending the exit interview conducted on March 11, 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. Plant Operations

Unit 1 operated at power with no significant operational problems during the period until February 12, 1994, when the unit was shutdown for cycle 13-14 refueling outage.

Unit 2 operated at power during the period with no significant operational problems until January 21, 1994, when a unit shutdown was commenced from 90 percent power to investigate a steam leak in the vicinity of steam generator (SG) No. 1. The licensee subsequently determined that the leak was on a one inch SG blowdown drain line. The licensee determined that the cause of the leak was a weld defect where the line connects to a 2 to 1 inch reducer. The unit was placed in Mode 5 to repair the weld, and was returned to service on January 27, 1994.

On February 21, 1994, the unit tripped from 60 percent power due to low-low SG level. This event is discussed in paragraph 3. During the forced outage, the licensee replaced the main generator exciter rotor due to vibration problems. During the initial roll of the main turbine following the forced outage, the licensee experienced high vibration levels on the main generator. The Unit was placed in Mode 3 to replace the generator rotor.

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; and verified that electrical power was available.

1) During resident routine tour of the control room in early January 1994, the inspector found a memorandum dated December 28, 1993 from the Operations Department on "Inappropriate Tour Signoffs." The memorandum, addressed to the shift supervisors, discussed the results of an operations department audit where certain auxiliary equipment operators signed for performance of a tour which were not performed.

   The recent memorandum was prompted by a licensee internal audit of AEO tours that found five individuals that appeared to have missed room tours. The inspector learned that the licensee was conducting internal audits in response to Information Notice 92-30, "Falsification of Records."

   The inspector reviewed additional audit reports and found that this issue was identified previously by an operations audit report dated October 27, 1992. This internal audit identified discrepancies with 8 out of 30 randomly selected tours during the months of July, August and September 1992. The discrepancies included AEOs failing to make tours of both safety and non-safety related rooms and a few instances were AEOs signed for room tours that another operator had performed. Additionally, the internal audit concluded that based on the time the AEO spent performing tours in the room a complete and thorough tour was generally not being performed by the AEOs. Pending further review by the NRC, the effectiveness and quality of AEO rounds will be an Unresolved Item (50-315/94002-01(DRP);50-316/94002-01(DRP)).

2) The inspector observed the licensee's Unit 2 turbine roll on January 26, 1994. At about 4:06 PM, the turbine tripped at approximately 1330 revolutions per minute (rpm). No abnormal indications or alarms preceded the turbine trip to warn the operators of any potential problems. The operators broke vacuum in the main condenser to reduce the turbine coastdown through one of the turbine's critical speeds, when

the vibrations on the No. 6 bearing reached 15.8 mils on the control room indication. The number five and six bearings support the main generator rotor.

On the next day, while the turbine generator was turning at about 1200 rpm, the inspector observed main lube oil pressure fluctuations that shook the lube oil piping. This main lube oil pressure fluctuation caused pressure spikes to occur on the turbine emergency oil circuit. The Instrument and Control (I&C) technicians had suspected that the fluctuations in the emergency oil circuit may have caused the turbine trip on the previous day and had installed pressure instruments and charts to monitor the fluid pressure. The shift manager discussed the situation with the turbine engineer on the phone. The turbine engineer suggested that the main lube oil fluctuations were probably caused by the transfer of the oil supply from the motor-driven to the shaft-driven oil pump. The turbine engineer recommended that the operators increase turbine speed. The operators increased turbine speed to 1800 rpm and was successful in paralleling the generator to the grid. The licensee's investigation into the lube oil fluctuations will be an Inspection Followup Item (50-316/94002-02(DRP)).

The inspector noted the following concerns with this plant evolution:

- The operators had not written a condition report for the turbine trip. After discussion with the inspector, the shift test advisor wrote Condition Report 94-120 to address the turbine trip and the pressure fluctuations on the main lube oil piping and the emergency oil circuit. The operator's identification of equipment problems through the use of the plant Condition Report system will be an Inspection Follow-up Item (50-315/94002-03(DRP); 50-316/94002-03(DRP)).

- The inspector noted that the operations department representative that provided management coverage for the turbine roll did not have any operational experience. Although at the Cook plant for 11 years, the individual's experience was predominantly in the maintenance department. Based on discussion with the operations department superintendent, the inspector determined that other on-going activities required operations management involvement that day and an experienced manager for the turbine roll-up could not br assigned. Operations management coverage for future turbine startup will be an Inspection Follow-up Item (50-315/94002-04(DRP); 50-316/94002-04(DRP)).

b. Onsite Event Follow-up (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that any required notification was correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

- On February 5, 1994, the licensee reported a condition that was potentially outside the design basis of the plant as required by 10 CFR 50.72. During the as-found testing performed on February 3-5, 1994, 13 of the 20 Unit 1 main steam safety valves (MSSV) exceeded the 1 percent Technical Specification (TS) limit. Ten of these failures exceeded the setpoint by greater than 3 percent. One failed to open after a lift pressure 9.8 percent above its setpoint was applied. This was the maximum lift pressure obtainable by the test equipment. The inspector's previous review of these failures was discussed in paragraph 4.a of inspection report 50-315/92009(DRP);50-316/92009(DRP). Ten of the 13 valves that failed lifted within the 1 percent TS limit on the second test without adjustment.

  The licensee decided to test the Unit 2 MSSVs in response to the Unit 1 failures. Nine of the 20 valves did not lift within 1 percent of their design setpoints on Unit 2. However, all the valves lifted within 3 percent. The licensee has completed an evaluation which concluded that a 3 percent deviation was acceptable from a design basis perspective.

  The licensee established a task team to investigate the root cause of the set point drifting and the disparity between the results of the Unit 1 and 2 testing. Preliminarily, the licensee believed that the disparity was due to an inverse relationship between the number of Main Steam System pressure transients and the magnitude of the drifting. While Unit 1 had been operating at 100 percent power for the majority of its 470 continuous days of operation, Unit 2 has been shutdown numerous times during the present cycle for forced outages. A review of the units' operating history appeared to support the hypothesis.

  During discussions with the valve manufacturer, the licensee identified that bonding between the valve body and disc seats may be a potential cause of the set point drift. The licensee disassembled the valve which failed to lift during testing (1-SV-2B-1) for inspection. The licensee discovered a thin oxide film on the valve body and disc seats that was

evidence of potential bonding. The licensee intended to send the valve disc offsite for further analysis. The inspector's review of the causes for the failure of the MSSVs to lift within their acceptance value is an Inspection Followup Item (50-315/94002-05(DRP); 50-316/94002-05(DRP)).

- On February 12, 1994, while in Mode 3, both motor-driven auxiliary feedwater (MDAFW) pumps were started in preparation to secure the main feedwater pump. Shortly after starting the pumps, elevated temperatures were observed on the West (W) MDAFW pump casing and discharge piping. Per the licensee's procedure, the MDAFW pumps had been started with each pump's discharge valves shut, with dead head protection being provided by a shared mini-flow line to the condensate storage tank (CST). The elevated temperatures were caused by a blockage of the mini-flow line that resulted in both MDAFW pumps being run dead-headed. The licensee determined that the cause of the blockage was a frozen section of piping adjacent to the CST due to a blown fuse in a heat-trace circuit.

  The inspector interviewed the AEOs and determined that the pumps were in this "dead-head" configuration for about 15 minutes while a reactor operator investigated the elevated temperatures. The operators postulated that there were problems with the mini-flow piping and initiated flow to the steam generators to lower pump casing and discharge piping temperature. The licensee also stationed a reactor operator locally at the pumps to detect any further problems and verified that there were no problems with the mini-flow piping associated with the other auxiliary feedwater pumps for Units 1 and 2.

  On the following day, the licensee reenergized the heat-tracing, thawed out the Unit 2 mini-flow piping, and conducted performance tests to verify that the W-MDAFW pump's capacity was unimpaired.

  During the review of the event, the inspector determined that the heat tracing and insulation on the Unit 2 mini-flow piping were replaced late in 1992 by minor modification, 12-MM-412. Subsequent to that, the licensee identified two occurrences of blown fuses to power supplies to the CST heat tracing circuits. The licensee identified the root cause for those incidents to be overloading of the heat trace circuits by non-heat trace loads on service outlets. As corrective action, the licensee removed the service outlets from the heat trace circuits.

  The licensee root cause and corrective action for the February 12, 1994 frozen pipe, including an assessment of the actions taken to the prevent the previous incidents, is

an Unresolved Item pending further review by the NRC (50-315/94002-06(DRP)).

- On February 16 through 18, 1994, the inspector observed portions of the Unit 1 reactor coolant system (RCS) drain-down evolution . Due to concerns regarding a loss of operator control of RCS level during the draining evolutions, a special inspection was conducted to review the event. The results of this inspection are documented in NRC Inspection Report 50-315/94004 (DRP).

- On February 21, 1994, valve 1-ICM-129, "RCS Loop 2 Hot Leg Cooldown to RHR Pump Suction Containment Isolation Valve", unexpectedly closed when energizing control power to the valve. The refueling water storage tank was also aligned to the RHR suction. The reactor cavity had been filled prior to this event by gravity feed from the RWST. The licensee used Procedure "Operation of Refueling Cavity and Support System," that required throttling valve 1-ICM-129, to allow less flow from the RCS and more flow from the RWST to continue filling the reactor cavity. During this event, at no time was there a loss of forced cooling through the reactor core.

  The inspector reviewed the event and determined that valve, 1-ICM-129, was normally maintained in the open position and deenergized when the RCS was depressurized to prevent inadvertent closure and loss of flow to the operating RHR pump. The licensee plans included energizing the valve at the motor control center (MCC) so that the valve could be electrically throttled closed . However, when the breaker for the valve was closed at the MCC, the valve went closed due to a signal from the RCS pressure switch, NPS 121, that had been removed from service for a reactor protection system modification. The pressure switch provides intersystem LOCA protection for the RHR system by initiating a close signal to valve ICM-129 to isolate the RHR from the RCS during RCS pressure conditions that were above the RHR design pressure.

  As immediate corrective action, the licensee performed a review of the RPS modification to determine if there were any other discrepancies that were not identified during the initial review.

  During follow-up investigation, the licensee identified that Section 9.3.3 of the UFSAR stipulated that 1-ICM-129 had to be deenergized when the RCS was open to the atmosphere. The licensee determined that no safety evaluation was performed for the deviation from the UFSAR, as required by 10 CFR 50.59. Condition report 94-310 was written to address this concern. Additionally, "Operation of Refueling Cavity and

Support System," procedure did not specify the method for throttling the valve. However, the inspector determined that remote electrical operation of the valve was the preferred method over manual operation of the valve. The inspector's review of the licensee's root cause and corrective action for this event is considered an Unresolved Item pending further review by the NRC (50-315/94002-07(DRP)).

- On February 26, 1994, at 12:29 pm, the Unit 1 Volume Control Tank (VCT) indicated level went to "0 percent". The VCT was providing the net positive suction head for the East Centrifugal Charging Pump (E CCP), 1-PP-50E that was running to supply flow to the reactor coolant pump seals and reactor coolant loops. At the time, Unit 1 was in a refueling outage with no fuel in the reactor and the reactor cavity flooded. The licensee issued Condition Report 94-0337 to document and investigate the circumstances that led to the loss of VCT level.

  The inspectors performed a preliminary review of the event and determined that prior to the event there had been a small mismatch between the flow to the VCT from the Residual Heat Removal (RHR) system and the discharge flow of the E CCP. This resulted in a slow decrease in the VCT level from 38 percent to 20 percent during the morning of February 26 between shift turnover at 6:30 am and 12:15 pm. At 12:15 pm, the control room licensed operator responsible for monitoring the panel with the VCT level and E CCP controls left the control room for about 15 minutes. At the time of the event the licensee was draining the reactor cavity. The inspectors interviewed the operator and determined that the operator did not discuss the changing VCT level with the relieving reactor operator. Because of the slow level change in the VCT, the operator believed there would be little change in the VCT level.

  There was no action taken by the control room operators to compensate for the decreased RHR flow to the VCT and increased E CCP flow caused by the draining of the reactor cavity. As a result, VCT level dropped from 20% to 0% in about twenty minutes. At 12:29 pm, the operator, who had returned to the control room noticed, VCT level was 0 percent. The operator secured the Unit 1 E CCP. An operator was sent to the E CCP room and found that the pump casing temperature was normal. The pump's discharge and suction were vented with some gas being released. The pump was then bumped and vented again with some gas again being released. The licensee evaluated the status of the E CCP and determined the pump was operable.
  At the time of the event, the VCT low level alarms and the automatic suction transfer to the refueling water storage

tank (RWST) on low VCT level were inoperable due to ongoing work on the analog to digital modification to the reactor protection system instrumentation. The inspectors were concerned with the lack of an adequate turnover between control room operators and the failure to be cognizant of plant conditions during significant plant evolutions. This matter is considered an Unresolved Item pending further NRC review (50-315/94002-08(DRP)).

c. 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. The inspector noted that in general the material condition of the plant was generally acceptable. Noted exceptions were as follows:

- On February 1, 1994, the inspector identified that the oil level in a sightglass for the Unit 1 TDAFW pump motor was at the minimum level. The inspector informed the shift supervisor of the condition. After discussion with the inspector, the shift supervisor directed an AEO to add oil to the motor.

- On February 4, 1994, the inspector identified that the oil level in the oil bubbler for the North Spent Fuel Pit pump outboard bearing was low. The bubbler indicated about 1/8 full. The inspector informed the shift supervisor who stated that an AEO would refill the bubbler.

- On February 4, 1994, the inspector observed construction personnel erecting a green canvas tent around the Unit 1 control room emergency exit to the 633 level of the auxiliary building. The inspector determined that the green canvas sheets enclosed an Appendix R emergency lighting pack that was installed to provide lighting to motor control center, 1-AM-1. The inspector reviewed the job order package and determined that the planners had been aware of this potential problem. The inspector notified the shift supervisor and questioned if the blocking of the emergency light with the unit in MODE 1 was acceptable. On the following day, the Plant Engineering Superintendent informed

the inspector that the emergency lighting pack should not have been blocked without some compensatory actions being taken. The inspector's review of the circumstances regarding the blocking of this emergency lighting pack is considered an Unresolved Item (50-315/94002-09(DRP)).

- On February 22, 1994, the inspector observed water spraying from a packing leak on the outboard bearing of the Unit 2 East motor-driven auxiliary feedwater pump. The pump was operating at the time, feeding the SGs after a reactor trip the previous day. The inspector notified the shift supervisor, who initiated an action request to tighten the packing and sample the bearing oil to verify no water intrusion.

- On March 1, 1994, during a plant tour, the Section Chief from NRC Region III, discovered that there was no oil indicated on the reservoir sight glass to the Unit 1 "South" safety injection (SI) pump. There was oil visible on the pump skid along with oily rags and a oil can. Discussion with an AEO determined that the pump had just been secured in preparation for a surveillance test. The AEO stated that the pump was to be restarted in a few minutes for the surveillance test. The AEO was aware there was an oil leak at the sightglass. However, the AEO was not aware there was no oil visible in the sight glass. When questioned, the AEO stated that there was oil visible in the sight glass when the pump was running. The AEO subsequently added oil to the SI pump prior to the surveillance test.

d. 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. The inspector noted that housekeeping and plant cleanliness were acceptable. Because of the Unit 1 outage, there were items such as anti-contamination clothing and other equipment left unattended in the auxiliary building. However, in general, housekeeping in the turbine and the auxiliary buildings was satisfactory.

The inspectors also toured lower containment, the annulus region and the basement areas of Unit 1. The inspector found that the basement area of Unit 1 containment was not maintained as well as either the turbine or the auxiliary buildings. In general, the Unit 1 basement area was not well lit, and had many areas in which there was boric acid deposits and water on the floor.

3. Maintenance/Surveillance (62703 & 61726)

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. The inspectors had concerns with the following maintenance activities:

- The inspector reviewed licensee records for the maintenance activities performed on February 21, 1994, under Job Order (JO) C0021542. The maintenance was performed on one of the two dump valves associated with main steam stop valve (MSSV), 2-MRV-240. This JO was initiated to repair the leak-by on dump valve 2-MRV-241. Opening of either of two dump valves associated with an MSSV would cause the MSSV to shut. The air operated dump valves fail open upon loss of air.

  The scope of work for JO C0021542 included disassembly of the valve, bench testing of the actuator, replacement of the valve internals, reassembly of the valve, coupling of the actuator to the valve, and stroke timing the valve. The maintenance on 2-MRV-241 was performed at power and rendered the associated MSSV inoperable, which required entry into a 4 hour Technical Specification (TS) Limiting Condition for Operation (LCO). Work planning and the staging of equipment were very important due to the amount of work to be performed and the LCO time constraints.

  The valve was disassembled, internals replaced, and reassembled. The valve was then stroke tested and left in the closed position. When the valve was returned to service, system steam pressure and the force of the actuator spring were sufficient to open 2-MRV-241. This caused main steam stop valve 2-MRV-240 to close and a subsequent reactor trip on low-low steam generator level.

  The licensee initiated the repair because leak-by on an MSSV dump valve could lead to the accumulation of condensate on top of the MSSV closing piston. This condensate will flash to steam instantly when the cylinder on the MSSV depressurizes from a dump valve opening. This phenomena adversely affects the stroke time of the MSSV. The Technical Specifications require the MSSV to close in 8 seconds. For this reason, leak-by on the dump valves must be minimized to ensure MSSV operability. This issue was the subject of NRC Inspection Report 50-315/90005(DRP); 50-316/90005(DRP).

  The licensee's investigation into the reactor trip on February 21, 1994, determined that the cause for valve 2-MRV-241 opening was incorrect coupling of the valve actuator to the valve stem. The inspector determined that the coupling of valve 2-MRV-241 was not

conducted in accordance with an approved procedure. Although a procedure existed for this activity, procedure 12IHP6030.IMP.030, "Inspection & Adjustment of Pneumatic/Spring Valve Actuators & Associated Positioner & Limit Switches," the procedure was not followed. Specifically, the as left valve stroke length did not correspond to the required stroke length, as required by Step 6.5.4.

Plant Manager Instruction, PMI-2010, step 4.17.2, states that technical documents that were intended to be used by qualified individuals during the performance of an activity shall be designated In-Hand. However, licensee procedure 12IHP6030.IMP.030, which covered maintenance activities performed on valve 2-MRV-241 including bench set of the actuator, coupling the actuator to the valve, verifying positive seating, and verifying proper stroke length, was not designated "In-Hand". Consequently, the procedure was not followed, and the valve was returned to service without the proper stroke length. As a result, an improper stroke length caused the dump valve to unexpectedly open when the valve was returned to service.

The failure to accomplish maintenance in accordance with procedure 12IHP6030.IMP.030, and the failure to designate procedure 12IHP6030.IMP.030 as In-Hand, are considered examples of a violation of Criterion V of Appendix B to 10 CFR Part 50 (50-316/94002-10(DRP)).

Additionally, the inspector noted that Step 6.3 the procedure did not specify what air pressure was required to be applied to the actuator while coupling the actuator to the valve stem. This could result in insufficient air pressure being available to the valve to overcome the opening force exerted by the main steam pressure on the valve.

Procedure 12IHP6030.IMP.030 had been revised on August 19, 1993, and the maintenance performed on February 21, 1994, was the first time this revision of the procedure was used for work on an MSSV dump valve. Three other leaky dump valves were repaired in January 1993 using Revision 4 of the procedure. Discussions with various licensee personnel involved determined that the procedure was revised because the valve actuator vendor recommended bench setting of the actuator. In the new procedure (Revision 5), a bench set ensures that a given air pressure would result in the required amount of actuator movement. Previous practice at the plant was to set the actuator for the required stroke length while the actuator was coupled to the valve stem.

- The inspectors reviewed an event that occurred during the disassembly of bleed steam condensation valve, 1-B-295. The licensee initiated Job Order C0070028 to disassemble and repair 1-B-295 because the valve's handwheel moved without movement of the valve stem. During the disassembly, the valve's bonnet became a

projectile because a section of the piping was still pressurized. The inspector determined that the event was caused by a change to the clearance permit which caused a section of the piping to remain pressurized.

Valve 1-B-295 was found stuck in the closed position. The original clearance permit required that valve, 1-B-177, an isolation valve to the main condenser, be closed after isolation valves from the bleed steam system were closed. However, due to a concern that main condenser vacuum could be lost, the Unit Supervisor changed the sequence to require that 1-B-177 be closed first. The change in sequence resulted in a portion of the piping remaining pressurized.

An AEO signed on the clearance that the system was drained and vented after apparently observing drops of water leak from an open valve used to drain a portion of the piping. However, several hours later, the maintenance supervisor observed a steady, pencil-thin stream of water draining from the valve and determined that the system was potentially pressurized due to the evidence of leakby. Therefore, the mechanics took safety precautions during the disassembly of the valve.

At the conclusion of the inspection period, the inspectors were still assessing this event. This matter is considered an Unresolved Item pending further NRC review (50-315/94002-11(DRP); 50-316/94002-11(DRP)).

4. Engineering & Technical Support (37700)

The inspector 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. The following issues were reviewed by the inspectors:

- The licensee identified in 1992, that some taped electrical splices installed in harsh environments between 1983 and 1992, did not meet the requirements of 10 CFR 50.49 ("Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," issued in 1983). This regulation required, in part, that replacement components be upgraded to meet 50.49 requirements. The only 10 CFR 50.49 qualified splices allowed at the plant were "Raychem" splices.

  The licensee verified that all of the taped splices were qualified to the older "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," dated November 1979 (DOR Guidelines). The difference between the DOR Guidelines and the 10 CFR 50.49 requirements was that 0 CFR 50.49 required components to be subjected to pre-aging

prior to qualification tests. The DOR Guidelines did not have this requirement.

The licensee failed to communicate 50.49 requirements through the procedural guidance that was provided to the electricians. Procedures and drawings did not specify the appropriate splices for use in EQ applications. Another contributing factor was the lack of on-site management oversight until 1991. This contributed to the excessive length of time that the problem existed. Corrective actions included changes to the drawings to include notes warning against the use of taped splices on EQ components. The inspectors agreed that the corrective actions were adequate, but encouraged the licensee to provide even clearer guidance to workers. The licensee agreed to make further procedural changes to identify specific splice requirements and to provide applicable training to electricians and work planners. These steps appeared to be acceptable.

Other corrective actions included the identification and replacement of all taped splices installed on 4KV motors since 1983, and motor-operated valves (MOVs) worked since 1991. Steps were not taken, however, to correct some of the taped splices installed on MOVs between 1983 and 1991, and other EQ equipment between 1983 and 1992. The licensee indicated that difficulty in retrieving maintenance histories from the old Artemis data base presented a significant impediment to identifying affected components. The inability to easily obtain maintenance history information, which would have allowed the identification of all the affected splices, was considered to be a weakness.

Contact with EQ experts from the Office of Nuclear Reactor Regulation determined that the safety significance of this issue was minimal. The use of taped, instead of Raychem, splices would not likely affect the operability of any components during a design basis accident.

The inspectors identified that work planners received no EQ training. Since the work planners were responsible for identifying EQ work, some amount of EQ training applicable to the job would be appropriate. The licensee agreed to consider providing additional EQ training to the planners. The inspectors verified, through discussions with maintenance personnel, that electricians received appropriate training regarding the installation of Raychem kits.

The failure to upgrade the splices, during replacement, to meet the 50.49 requirements was a violation of NRC regulations. However, this violation was not cited because the licensee identified the problem and initiated appropriate corrective actions. Therefore, pursuant to the NRC enforcement policy (10 CFR 2, Appendix C) the NRC is exercising enforcement discretion for this matter, and no Notice of Violation will be issued.

The licensee identified, approximately two years ago, that some components in the plant did not have the appropriate drainage configuration as specified on the drawings. The licensee identified all the problems, performed the appropriate modifications, performed QC inspections to ensure that all of the configuration problems were corrected, and initiated steps to clarify drawings so that the problems would not recur. These steps appeared to be acceptable.

- The inspector reviewed the licensee's actions concerning the Unit 1, No. 14 reactor coolant pump (RCP) motor lower radial bearing low oil level, and the resulting damage to the bearing.

In late September 1993, "RCP #4 Lower Oil Pot Low" annunciator alarmed on Unit 1. The licensee evaluated the alarm and determined that the alarm was valid. A decision was made to continue operation of the RCP until there was an opportunity to add oil. In the interim, the bearing temperature was monitored and guidance was issued to the operators. The licensee consulted Westinghouse, who was the vendor for the RCP, regarding the acceptability of continued operation of the motor with low oil level. The licensee decided that since the bearing had only slight loading during normal operation, continued operation of the motor would be acceptable until the Unit 1 refueling outage scheduled for February 12, 1994.

The RCP operated in this condition for the next four months, with only a slight increase in bearing temperature. At about 7:15 PM, on January 27, 1994, the bearing temperature suddenly spiked to above the high temperature alarm setpoint and caused the "RCP # 4 Lower Radial Bearing Temperature" alarm to annunciate. The inspector's review of the control room logs and discussion with the operators found that the bearing temperature increased from 155 degrees Fahrenheit (F) to 302° F and finally stabilized at 218° F. The licensee's review identified that this temperature increase was preceded by a component cooling water (CCW) system temperature decrease of 10 to 15° F. The licensee postulates that the CCW system temperature decrease may have cooled the bearing oil enough to shrink the oil volume to a level below that needed to provide adequate lubrication, resulting in damage to the bearing. Subsequent to the lower radial bearing temperature excursion, the Operations Department Superintendent had given permission to raise the CCW temperature to as high as 105° F. Review of the authorization to raise CCW temperature to 105 degrees is considered an Unresolved Item pending further NRC review (50-315/94002-12(DRP)).

Because the system engineer desired to regain the alarm feature for the RCP lower motor radial bearing, he recommended that consideration be given to place the spare resistance temperature detector (RTD) in operation. Additionally, the inspector determined through discussion with the engineer that the engineer

believed the RTD reading of 200° F was faulty based on a similar event in the past. There were two RTDs installed to monitor lower radial temperatures. These RTDs were embedded in 2 of a 7 piece bearing assembly and were located 180 degrees apart. Based on the temperature excursion observed on the RTD, the system engineer concluded that possibly the RTD may have been damaged along with the lower radial bearing. The spare RTD was placed in service and indicated a temperature of 155° F. The licensee considered the spare RTD to be more representative of actual bearing condition based on past historical bearing temperatures. Additionally, the installation of the spare RTD restored the alarm feature to alert operators of another temperature excursion.

Because a temperature reading of 200° F was not totally unreasonable, the inspector contacted the I&C technician involved with the troubleshooting associated with the RTD to determined whether there was data that would indicate a bad RTD. The inspector noted that the I&C technician had measured the RTD resistance to be 222 ohms. In the past, it read in the range from 175 to 200 ohms. Secondly, the inspector requested a table of "resistance as a function of temperature" for this RTD and verified that a resistance reading 222 ohms corresponded to a temperature reading of about 200° F.

After questioning by the inspector, the licensee reconsidered which RTD should be monitored. At this time, the system engineer realized that as part of the vibration monitoring for this bearing, indications existed that the motor shaft had physically moved in the direction of the original RTD at the same time as the temperature spike. This served to confirm that actual bearing damage may have occurred and the reading on the original RTD was a valid and should be monitored to ensure that the operators would be monitoring the bearing with the higher temperature reading. The inspector concluded that the engineering decision to switch to the spare RTD could not be supported by any available engineering data.

On February 4, 1994, the original RTD was returned to service. The alarm setpoint was raised from 185 to 230° F to clear the standing alarm. Guidance was also issued to inform the operators of the bearing status. Local monitoring of the spare RTD was initiated and monitored by the system engineer. The motor operated in this condition until the unit shutdown on February 12, 1994.

The inspector reviewed the maintenance history of all Unit 1 and Unit 2 RCP motors. This review identified that lower radial bearing oil level had been a recurrent problem in the past. However, in 1989, the licensee performed a modification to all RCPs that replaced the lower bearing seal and oil pan, that were previously aluminum, with components made of carbon steel. This modification was recommended by Westinghouse, and eliminated the

majority of oil leakage caused by deformation of these components that led to ineffective seals. Since this modification, the January 27, 1994 event was the first instance of damage to a bearing caused by low oil level. The licensee is currently disassembling the RCP to determine the cause of the low oil level and extent of damage to the bearing. This matter is considered an Inspection Followup Item pending further review by the licensee and the NRC (50-315/94002-13(DRP)).

- The inspectors reviewed licensee records for the installation of a clamp on valve 2-CS-328-L4, and subsequent Furmaniting of the valve to stop a body to bonnet leak. This valve, located on the normal charging line to the reactor coolant system, was Furmanited in August 1993 and re-Furmanited in January 1994. The valve was classified as an ASME Section III, Class I valve. The records reviewed included calculations for estimating the amount of flange compound estimate and injection pressure. Also, the calculation for determining the increased load on the valve's flange studs caused by the Furmanite process were reviewed by the inspectors . The review identified the following concerns:

  1) The vendor, Furmanite, did not perform a flange stud calculation for the August 1993 Furmanite of valve 2-CS-328-L4. This calculation was required to determine if the load applied to the valve's flange studs would be less than 2/3 of the yield strength of the studs.

  2) The flange stud calculation that was performed for the January 1994 re-Furmaniting of valve 2-CS-328-L4 had the wrong acceptance criteria for yield strength and used a wrong dimension for the flange diameter that resulted in a less conservative result. The acceptance criteria for the yield strength was 70,000 psi instead of 56,666 psi. Subsequent flange stud calculations using the correct dimension and acceptance criteria determined that the load on the flange studs would be less than 2/3 of the yield strength.

  The inspectors also determined that the licensee had Furmanited two other ASME, Section III, Class I valves. The valves were the pressurizer spray control valve and a vent valve on a RTD bypass manifold. The pertinent records for the Furmaniting of these valves will be reviewed by the NRC. This matter is considered an Unresolved Item pending further review by the NRC (50-315/94002-14(DRP);50-316/94002-14(DRP)).

No violations or deviations were identified.

5. Safety Assessment/Quality Verification (40500 and 92700)

The inspector reviewed the licensee's condition reports (CRs) 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. The inspector reviewed the licensee's preventive actions to a July 10, 1992 refueling event in which the manipulator crane mast gripper assembly finger became caught under the fuel assembly hold down spring. This event had previously been documented in NRC Inspection Report 50-315/92014(DRP);50-316/92014(DRP). After attempts to free the gripper from the fuel assembly through mast movement, rotation and cable manipulation failed, the licensee succeeded in releasing the gripper finger from the fuel assembly spring by cutting the spring using a special tool provided by Westinghouse. Although the licensee had successfully identified and corrected a number of potential factors which contributed to this event, the inspector found that the improvements to the refueling procedure to detect and further minimize this event from occurring in the future was weak since there was no procedural requirement for the operator to verify proper alignment and engagement of the gripper and fuel assemblies.

Based on the inspector's discussion with the operation department staff personnel responsible for the refueling procedures and a senior reactor operator - core alterations (SRO-CA), further procedural improvements were made as part of change sheet 4 to "Fuel Handling and Tool Checkout" procedure, **01-OHP 4050.FHP.003, Revision 2, February 7, 1994. The licensee added the following requirement to the "Fuel Handling and Tool Checkout," procedure:

> "While lowering the manipulator mast to engage a Fuel Assembly, the crane operator shall monitor the dillon load cell for unusual conditions. A spotter shall observe the gripper assembly and the fuel assembly interface and verify proper alignment. The crane operator shall receive verification from the spotter prior to engaging the fuel assembly. In the event of an abnormal condition, the mast movement shall be stopped, notify the SRO-CA and Refueling Shift Supervisor. A binocular or camera inspection shall be performed as deemed necessary by the SRO-CA prior to continued hoist operation."

Furthermore, the procedure defined an unusual condition as follows:

> "Loss of greater than 200 pounds at an elevation above the full down as determined by the ZZ axis tape" and
>
> "misalignment of the gripper guide pins in relation to the fuel assembly as observed by the spotter."

No violations or deviations were identified.

6. Refueling Activities (60710)

During the refueling outage, the inspectors observed the licensee's fuel handling operations and discussed refueling operations with plant operators and fuel handling personnel. The licensee used approved procedures for fuel accountability and movements. Communications between the technical support center (TSC) and fuel handlers were established and effective. The inspectors witnessed fuel handling operations from the TSC, in the fuel building, and in containment. The inspector did not identify any concerns during the evolution.

During this Unit outage, all of the fuel was unloaded from the reactor, moved to the spent fuel pool, ultrasonically tested for indications of fuel leaks, and stored in the spent fuel pool. Prior to the outage, the licensee initiated a design change to install the refueling machine in-mast sipping system to provide a higher degree of accuracy in identifying fuel defects. The new system replaced the old sipping method which was performed previously in the transfer canal tube. The new system was installed after the licensee apparently reloaded at least one defected fuel assembly during the last refueling outage. The system provided a means of performing on-line, quantitative leak testing of the fuel assemblies in the refueling mast during normal fuel handling operation. The system operates during the change in elevation of the fuel assembly from the in-core position to the full-up in-mast position. This results in a differential pressure which causes fission gases to migrate out of any open defects in the fuel rod cladding. An air sample is then taken from the mast and analyzed by the detection module.

The licensee identified a total of 13 fuel assembly defects using the combination of sipping and UT methods. Eleven of the 13 defects were identified by both methods. Two of the defects were identified by the sipping only. Of the 13 assemblies with defects, 9 had been in the core for three cycles and were not going to be reloaded into the core. The other 4 assemblies had been in the core for two cycles and will be replaced by spare twice-burned assemblies.

The inspector noted that the licensee did not detect any fuel defects during the previous outage. The inspector reviewed licensee records with regards to steady-state I-131 dose equivalent activity prior to the plant shutdown and noted that levels were comparable to those during the previous cycle, at approximately 3E-3 microcurie/ml. The licensee's TS limit is 1 microcurie/ml.

No violations or deviations were identified.

7. Inspection Followup Items

Inspection followup items are matters which have been discussed with the licensee, which will be reviewed by the inspector and which involve some action on the part of the NRC or licensee or both. Inspection followup Items disclosed during the inspection are discussed in paragraphs 2.a 2); 2.b and 4.

8. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in paragraphs 2.a 1); 2.b; 2.c; 3 and 4.

9. Meetings and Other Activities

a. Management Meetings (30702)

On February 28 through March 3, 1994, Mr. W J. Kropp, Section Chief 2A, Division of Reactor, projects toured the D. C. Cook plant and met with licensee management to discuss plant performance and plant material condition.

b. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 during the inspection period and at the conclusion of the inspection on March 11, 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.