U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Report Nos. 50-315/90023(DRP); 50-316/90023(DRP)

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

Licensee: American Electric Power Service Corporation
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: October 10 through November 13, 1990

Inspectors: J. A. Isom

D. G. Passehl

Approved By: B. L. Jorgensen, Chief 11/29/90
Projects Section 2A Date

Inspection Summary

Inspection on October 10 through November 13, 1990 (Report Nos. 50-315/90023(DRP); 50-316/90023(DRP))
Areas Inspected: Routine unannounced inspection by the resident inspectors of: plant operations; ESF actuations ; radiological controls; maintenance; surveillance; engineering and technical support and safety assessment quality verification.
Results: Of the seven areas inspected, no violations or deviations were identified. The inspection did not disclose any major weaknesses in the licensee's programs or their implementation of these programs. The inspection did note a strength in the area of conservative management operating philosophy in the resolution of various technical issues encountered during the restart of Unit 2.

Plant Operations:

During this reporting period, Unit 1 began its cycle 11-12 refueling outage. The Unit was taken off-line on October 20, 1990 and entered MODE 5 on October 21, 1990. At the end of the inspection period, the Unit was defueled, and making preparations to enter half-loop.

Unit 2 was in the process of entering MODE 2 at the beginning of the inspection period. The Unit was cooled down on a number of occasions in an effort to repair various valves which were found to be leaking. These valves included: a pressure isolation check valve, which was believed to be contributing to the pressurization of the safety injection header; steam dump

valves of a "new" design which would not close and were eventually replaced with valves of the "old" design from Unit 1; and repair of the body-to-bonnet leak on a pressurizer sample valve. Additionally, the licensee identified and successfully repaired a problem with their reactor trip breakers which caused a spurious ESF actuation late in the inspection period. Although it appeared that the restart of Unit 2 had more problems than encountered by the licensee in the past, it was noted that resolution of various technical problems was approached with conservative management operational philosophy.

Maintenance and Surveillance:

Review of various job orders and surveillances during this inspection period indicated that maintenance and surveillance activities were, generally, conducted in a satisfactory manner and the inspectors noted no problems in this area.

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DETAILS

1. Persons Contacted

   a. Management Meeting - October 24, 1°90

      (1) American Electric Power/Indiana Michigan Power

      D. H. Williams, Jr., Senior Executive Vice President, AEP
      M. P. Alexich, Vice President, Nuclear Operations, AEPSC
      T. Argenta, Assistant Vice President, Nuclear Engineering, AEPSC
      A. A. Blind, Plant Manager
      K. R. Baker, Assistant Plant Manager, Production
      T. P. Beilman, Maintenance Superintendent
      J. B. Droste, Technical Support, Engineering
      E. V. Kincheloe, Training Superintendent

      A number of other licensee representatives were also present at the meeting.

      (2) Nuclear Regulatory Commission Personnel

      A. B. Davis, Regional Administrator, Region III
      H. J. Miller, Director, Division of Reactor Safety, Region III
      T. O. Martin, Deputy Director, Division of Reactor Safety, RIII
      R. C. Pierson, Director, Project Directorate, III-I, NRR
      H. B. Clayton, Chief, Projects Branch 2, Region III
      E. R. Schweibinz, Senior Project Engineer, Region III
      T. G. Colburn, Senior Project Manager, NRR
      H. A. Walker, Reactor Inspector, Region III
      J. A. Isom, Senior Resident Inspector, Region III
      D. G. Passehl, Resident Inspector, Region III

   b. Management Meeting - November 8, 1990

      (1) Licensee Personnel

      M. P. Alexich, Vice President, Nuclear Operations, AEPSC
      A. A. Blind, Plant Manager
      K. R. Baker, Assistant Plant Manager - Production
      J. E. Rutkowski, Assistant Plant Manager - Technical Support
      B. A. Svensson, Executive Staff Assistant
      S. J. Brewer, Manager, Nuclear Safety and Licensing, AEPSC
      T. K. Postlewait, Project Engineering Superintendent
      T. P. Beilman, Maintenance Superintendent
      R. R. Rickman, Unit 1 Outage Manager
      M. J. Stark, System Engineering Supervisor
      D. J. Moeller, Nuclear Safety and Licensing Engineering, AEPSC
      D. E. Vandeusen, System Engineer
      T. A. Georgantis, Nuclear Engineer, AEPSC

(2) Nuclear Regulatory Commission

J. A. Zwolinski, Assistant Director for Region III and V Reactors, NRR
R. C. Pierson, Director, Directorate, III-I, NRR
H. B. Clayton, Chief, Projects Branch 2A, RIII
C. E. Carpenter, Project Engineer, NRR
J. A. Isom, Senior Resident Inspector
D. G. Passehl, Resident Inspector

c. Inspection - October 10 through November 13, 1990

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

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

*Denotes some of the personnel attending the Management Interview on November 16, 1990.

2. Operational Safety Verification (71707, 71710, 42700)

Routine facility operating activities were observed as conducted in the plant and from the main control rooms. Plant startup, steady power operation, plant shutdown, and system(s) lineup and operation were observed.

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

Evaluation, corrective action, and response to off-normal conditions or events, if any, were examined. This included compliance with any reporting requirements.

Observations of the control room monitors, indicators, and recorders were made to verify the operability of emergency systems, radiation monitoring systems and nuclear reactor protection systems, as applicable.

a. Unit 1 began the inspection period on coast-down from 100-percent reactor power for the cycle 11-12 refueling outage. On October 17, 1990 the unit was at 69-percent power and was taken off-line on October 20, 1990, when MODE 3 was entered. At this time, an RCS pressure boundary leak was discovered at a flow transmitter for the RCS loop one cold leg. Boration of the RCS commenced and MODE 5 was entered October 21, 1990 and the Technical Specification Action Statement relative to RCS pressure boundary leakage was satisfied. The leakage will be repaired prior to plant startup.

   The unit completed MODE 6 entry and the reactor vessel head was removed and placed on its stand on November 4, 1990. Fuel off-load was completed November 10, 1990.

b. Unit 2 began the inspection period in MODE 3, continuing plant heat up to complete the refueling outage which began in June, 1990.

   An Engineered Safety Features actuation occurred on October 10, 1990 which was caused by a hi-hi steam generator level on No. 21 Steam Generator while feeding the Steam Generators with auxiliary feedwater (paragraph 4.a). The unit commenced cooldown to MODE 5 on October 15, 1990 to repair a body-to-bonnet leak on a pressurizer sample valve and to repair seat leakage associated with a pressure isolation check valve (Paragraph 6.b.). The pressurizer sample valve was cut out and successfully replaced. The repair to the pressure isolation check valve was a result of operator identification of the pressurization of their south safety injection (SI) pump discharge header from the reactor coolant system. Based on recently completed surveillance testing which quantified the as-left leakage rates for the various pressure isolation valves and the location of their SI header pressure instrument, the licensee determined the most likely sources of the leakage were from 2-SI-152-S (4 inch check valve) and IRV-157 (.75 inch test valve). Although the repairs were initially believed to be successful, the licensee found that during the resumption of heatup of Unit 2, the SI discharge header was still being pressurized. Currently, the licensee is manually venting the SI discharge header using one of the SI system drain valves approximately every four to five hours to prevent lifting the SI discharge header relief valve, while a long term engineering resolution could be completed.

   The unit commenced heat up to MODE 3 on October 18, 1990. During this period, because of the problems encountered with the new main steam dump valves which were installed during this outage (Paragraph 9.a.), the main steam header was depressurized and condenser vacuum broken to allow repairs to the valves. The licensee took advantage of this delay in startup of Unit 2 and repaired pressurizer safety

valve 2-SV-45A which was found as leaking at about 0.1 gpm, and a pressurizer power operated relief valve (2-NRV-151,) which was also leaking slightly. Neither the pressurizer safety valves nor the power operated relief valves were scheduled to be worked this outage; however, the plant intends to refurbish all three pressurizer code safeties every refueling outage from now on.

Cooldown to MODE 5 commenced October 25, 1990 to repair 2-SV-45A and 2-NRV-151. Repairs were completed and a plant heat up started with MODE 3 being reached on October 31, 1990.

On November 7, 1990 MODE 2 was entered following repairs to Train B of the Solid State Protection System (paragraph 4.b.). Reactor power was increased to two-percent using steam dumps for temperature control and MODE 1 was reached on November 9, 1990. The unit was at 47.6 percent power, continuing testing and power ascension at the end of the inspection period.

b. The inspector reviewed the Operations Standing Order, "Motor Driven Auxiliary Feedwater Pump (MDAFP) Engineering Leakoff Flow", OSO.091, Rev. 1, October 18, 1990, and noted no problems with the revised Standing Order.

To prevent deadheading of the MDAFPs, each MDAFP has a recirculation line known as the emergency leak-off (ELO) line (flow is approximately 65 gpm). The current configuration of the ELO lines uses the same piping in the return path to the Condensate Storage Tank for both MDAFPs. When both pumps are operating, one pump will have a slightly higher discharge pressure than the other. The pump with the lower pressure becomes "deadheaded" due to this common piping. To prevent this undesired situation which may cause damage to the MDAFP, the Standing Order was written to ensure that the situation did not occur. The standing order was revised to allow an option to use a second return flow path to the Condensate Storage Tank through a test line.

As a long term solution of the commonly shared ELO line, the licensee is formulating a design change to be installed during the 1992 refueling outage. The Standing Order referenced above was issued as an interim guidance on this issue and was revised after the ESF event discussed in paragraph 4.a. of this report.

Other options available still include use of the Turbine Driven Auxiliary Feedwater Pump (TDAFP) with a MDAFP (the TDAFP has its own ELO line) or operating the MDAFPs with enough flow so that the associated ELO valves remained closed.

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

4. Reactor Trip(s) or ESF Actuations (93702)

a. On October 10, 1990 an engineered safety feature actuation signal was received on the No. 21 Steam Generator (SG) due to hi-hi level. At the time of the event, the unit was in MODE 3 with the reactor

trip breakers, main feedwater pumps, and main turbine tripped; the main feedwater isolation valves were closed. There were no equipment position changes or actuations resulting from the event.

Prior to the event, the No. 21 Steam Generator level was being increased via the auxiliary feedwater system to support testing. Because of the concern regarding shared emergency leakoff (ELO) lines, the operators used only one MDAFW pump to feed two Steam Generators while allowing the other two Steam Generators to steam down. In order to ensure that there was sufficient level in the steam generators while steaming down, the operators increased the level of the steam generator to approximately 65 inches while following the appropriate procedures. An operator observed the level slowly drifting upwards beyond 65 inches and shut the associated feedwater isolation valve. Level swell occurred, and the ESF actuation setpoint of 67 inches was reached. The operators received the ESF actuation alarm. The cause of the event was attributed to operator error - failure to monitor the SG level at the frequency required for existing plant conditions.

To correct the problem, management expectations concerning attention to control room panels were re-emphasized in a letter to shift personnel on October 10, 1990. Additionally, a review of the MDAFP ELO concern was performed, and the testing procedure being performed at the time of the event was reviewed for changes which would preclude testing near the ESF level setpoint.

b. While performing "SU(1) Instrumentation Checks Prior to Startup," 2 IHP 4030 STP.180, on November 5, 1990, an unexpected ESF actuation ocurred when both reactor trip breakers, in-series, tripped open when the technician attempted to close bypass breaker "B." Although the licensee's initial troubleshooting of the problem identified a faulty tester card in the Solid State Protection System (SSPS) Train "B," which was replaced, a similar problem recurred on November 6th and 7th, 1990 when the surveillance was resumed. On November 7th, 1990, a general warning light did not clear when the bypass breaker "B" was opened. Subsequent investigation found that the contacts 5 and 6 for bypass breaker "B" had high resistance which was fluctuating around 130 ohms. The normally expected contact reading was 0 ohms. Visual inspection of the contacts revealed a black, greasy substance covering the contacts. All contacts of bypass breaker "B" were cleaned and the as-left resistance readings were less than 1 ohm. The licensee is considering requirements to visually inspect and to measure contact resistances as a future preventive maintenance practice. Also, the licensee instituted a procedure enhancement to improve awareness of the general warning lights by the technicians performing the surveillance.

Because of the condition of the contacts found in bypass breaker "B," inspections were performed of reactor trip breakers "A" and "B" and bypass breaker "A." The resistance checks of the reactor trip breakers revealed no deficiencies. The two contacts in bypass breaker "A" which showed slightly higher resistance of approximately 5 ohms were cleaned and burnished. All as-left contact readings were less than 1 ohm.

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

5. Radiological Controls (71707)

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

On October 25, 1990 the licensee discovered that the gate leading to an extreme high radiation area was unlocked. The gate controls access to the Unit 1 Seal Water Injection Filter cubicle. Surveys of the area indicated the highest dose rate to be 4 R/hr at a distance of eighteen inches from the filter. No personnel were believed to have made an unauthorized entrance to the area which was believed to have been unlocked for approximately 1.5 hours.

The area was found open by a Maintenance Mechanic while preparing for a filter change. There were no inoperable systems associated with the event. The licensee reviewed personnel dosimeter results for the month of October and found no exposures beyond site administrative limits. The gate was immediately locked upon discovery of the condition.

To prevent recurrence of a similar problem, the licensee issued a Standing Order which incorporates independent verification of the locked or guarded gate. The closing mechanisms were checked as well on all the other extreme high radiation doors. Three doors which were difficult to latch closed were repaired.

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

6. Maintenance (62703, 42700)

Maintenance activities in the plant were inspected to ensure the maintenance activities reviewed were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications. The following items were considered during this review: the Limiting Conditions for Operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures; and post maintenance testing was performed as applicable.

The following activities were reviewed/inspected:

a. Job Order (JO) A052146: "Perform TREVITEST on all (Unit 1) Loop 4 Main Steam Safety Valves (MSSVs)." The licensee tested all twenty MSSVs on October 17-19, 1990 on all Loops because of an ISI requirement for an expanded test size should any MSSV on a single loop fail the TREVITEST. One Loop 4 valve failed the TREVITEST when it was found to lift 5 psig below the minimum lift value of 1054 psig. The job order and associated documentation were reviewed and no problems were noted.

The tests were accomplished with the unit still in MODE 1 following **12 MHP 4030 STP 048, "MSSV Verification Using TREVITEST Equipment." The procedure is used to satisfy Technical Specification surveillance requirements and provides for adjustment of the MSSV setpoint, if necessary.

Eleven of the twenty MSSV lift setpoints were outside the Technical Specification range of one-percent of the setpoint tolerance. Ten of the eleven valves were within the three percent allowance for which a Technical Specification change request was made and is currently under review. The out-of-range safety valves were immediately reset to within their specified range.

One MSSV failed to lift at 1144 psig (setpoint is 1074-1096) which was the maximum lift with the existing unit and test configuration. The valve was sent to an independent laboratory for testing. Test results were unavailable at the close of this inspection.

Approximately seven valves are scheduled for refurbishment during the current refueling outage.

b. Job Order (JO) 005835. The review of the job order which was issued to repair pressure isolation check valve 2-SI-152S, suspected to be leaking and contributing to the pressurization of the safety injection discharge header, noted no discrepancies. The maintenance activity was performed using approved procedures, and appeared to have been completed satisfactorily. The licensee's inspection of the check valve disc seating surface found slight pitting on the disc. The disc was lapped to remove the pitting, and the craft verified a satisfactory contact between the disc and the seat through the "blueing" test. Additionally, inspection of the disc for free movement was satisfactory and there was no restriction on any internal parts.

c. Job Order (JO) 013337. The review of the job order associated with a leaking pressurizer code safety valve (2-SV-45A) noted no discrepancies. The leak was discovered by noting a small rise in pressurizer relief tank level. The maintenance activity performed involved the installation and removal of the gagging device and did not require procedures. The tailpipe temperature for 2-SV-45A was noted in the job order as being 230 degrees Fahrenheit, a value which was higher than the tailpipe temperatures associated with the other two pressurizer code safety valves. Because the installation of the gagging device did not reduce the leakby, the licensee replaced the pressurizer code safety valve with a new one. The inspector's observation of the tailpipe temperature for the new 2-SV-45A in the control room on November 13, 1990 indicated that the leakby had stopped. The tailpipe temperature read 130 degrees Fahrenheit, a value close to the temperature of the pressurizer dog house where it is located, and lower than the tailpipe temperatures for the other two pressurizer code safety valves.

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

7. Surveillance (61726, 42700)

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

The following activities were inspected:

a. **1 THP 4030 STP.203 (Rev. 13): "Unit 1 Type B and C Leak Rate." On November 2, 1990 the licensee reported exceeding the 0.60 La. allowable limit for the total as-found containment leakage. A leak was discovered at a manway cover for the enclosure to valve ICM-305 (recirculation sump to residual heat removal and containment spray isolation valve). Although the valve itself had not yet been leak tested, measured leakage rate from the enclosure is an input to the overall allowable containment leakage rate. The licensee will repair the leaking manway cover prior to unit startup.

   This test included a branch of the Containment Penetration and Weld Channel Pressurization System (CPWCPS) which encompassed piping penetrations in "Zone 4" outside of containment. The test was a Type B test as defined in 10CFR50 Appendix J, and measured to ensure containment leakage rates are within the limits specified by Technical Specifications.

   The portion of the CPWCPS tested was outside containment and functions to supply air pressure via the Zone 4 piping to enclosed sleeves by which pipes or ducts enter containment.

   The CPWCPS system is scheduled for abandonment, with the exception of Zone 3 electrical penetrations, during the next set of refueling outages in 1992. Leak testing the containment is already accomplished in accordance with regulations. The air supply to the electrical penetrations will be retained, however, to prevent moist air from outside containment entering the penetrations and affecting the enclosed cables. The scope of work on the rest of the system, which is not considered an Engineered Safety Feature, will have air supply lines to the penetrations cut and capped on either side of the containment boundary. The containment penetrations will still continue to be subject to containment test pressure via Appendix J and the licensee's Technical Specifications.

b. 1 THP 6020 LAB.039 (Rev. 6): "Techniques of Oil and EHC Sampling," Section 5.13 was observed which included sampling of the Unit 1 CD Diesel Generator fuel oil for particulate contamination. The technicians performing the procedures were knowledgeable and careful with regard to preparing the samples for analysis. Two minor procedural problems were noted. The analysis procedure referenced

revision 4 of the sampling procedure (the current revision number is 6) and Step 5.13.10 of LAB.039 does not explicitly instruct the technician to reclose an isolation valve for the fuel oil pump's discharge pressure gauge (the valve is opened to allow taking of the sample). Procedure change sheets were written to correct the minor deficiencies.

The analysis of the amount of particulates present in the sample was also observed as described in a separate procedure (12 THP 6020 LAB.173 (Rev. 0), "Determination of Particulate Contaminant in Fuel Oils"). The inspector noted no problems with the analysis technique or the procedure used. The sampling procedure described the proper technique for obtaining a representative fuel oil sample; the analysis procedure provided a method to analyze the sample as required by the Technical Specifications and in accordance with ASTM Standards. The result of the analysis were 4.18 mg/l, below the 10.00 mg/l acceptance limit.

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

8. Engineering and Technical Support

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

a. RFC 12-2845, "Reduce the Capacity of the Steam Dump System." The request for change (RFC) was an upgrade to alleviate operational and maintenance problems associated with the steam dump system, and eventually became the "critical path" item towards startup of Unit 2. Maintenance and test activities on the valves were observed and no problems were noted.

The RFC was to be accomplished in part by reducing the number of condenser dump valves to 9 from the 21 total valves originally installed. The intended effect was to reduce the capacity of the steam dump system from 85-percent of full load to approximately 40-percent.

The 85-percent steam dump system was designed to allow the turbine generator to take a load reduction from 100-percent to the plant auxiliaries load without a reactor trip. The new steam dump capacity would permit the turbine to take a load reduction of about 50-percent without a reactor trip. A historical review of system performance found no cases where the turbine experienced a load rejection of greater than 40-percent.

Problems were encountered with the new Hammel-Dahl valves during post-installation testing. The valves would not complete the entire 3.5 inch stroke without binding in the last 0.5 inch of stroke. The licensee, with a representative from the valve manufacturer, could

not resolve the situation satisfactorily after extensive troubleshooting, and decided to remove the Hammel-Dahl valves and replace them with the "old" Fisher valves from Unit 1. (Unit 2 also had the Fisher valves but they were already shipped off site.) The Fisher valves from Unit 1 were refurbished and set up to match the original requirements of the RFC.

b. The licensee presented evidence of apparent "accelerated" wear of the Unit 2 thimble tubes at a meeting with the NRC staff on August 29, 1990 (ref. NRC Inspection Report 50-315/90-21(DRP); 50-316/90-21(DRP)).

   Because of a licensee prior commitment to inspect flux thimble tubes and because abnormal thimble tube wear was identified in Unit 2 during the last refueling outage, the licensee performed eddy-current testing of Unit 1 thimble tubes. Preliminary results of the Unit 1 Eddy Current results indicate occurrence of "accelerated" wear like the Unit 2 tubes, though not to such a severe degree. The tubes in both units were expected to have much slower wear rates. The licensee is still evaluating the root cause of the thimble tube wear and the results with corrective action will be part of future NRC inspections.

   After one cycle of Unit 2 operation with newly installed thimble tubes ten thimble tubes were worn enough, including one failure, to warrant replacement. Nineteen additional tubes were worn enough to warrant repositioning to realign wear surfaces to a location free of wear. Those actions were performed in addition to other commitments made to NRC by the licensee.

   One of those commitments was to provide NRC with Unit 1 Eddy Current test results following the current Unit 1 refueling outage. Unit 1 also operated one cycle with new tubes.

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

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

The effectiveness of management controls, verification and oversight activities, in the conduct of jobs observed during this inspection, was evaluated.

The inspector frequently attended management and supervisory meetings involving plant status and plans and focusing on proper co-ordination among Departments.

The results of licensee auditing and corrective action programs were routinely monitored by attendance at Problem Assessment Group (PAG) meetings and by review of Condition Reports, Problem Reports, Radiological Deficiency Reports, and security incident reports. As applicable, corrective action program documents were forwarded to NRC Region III technical specialists for information and possible follow-up evaluation.

On November 1, 1990 the inspector was contacted by NRC Region III staff regarding problems with U-bolts installed in an ice condenser plant similar to D. C. Cook. The information was gathered and given to the Cook plant staff.

The issue pertained to cracks discovered in the U-bolts which hold down the ice condenser baskets. The bolts were supplied by Westinghouse and a defect during the manufacturing process was believed to have occurred.

D. C. Cook performed a visual and hands-on inspection of all their ice baskets and found one broken U-bolt and 19 missing nuts out of 3,888 U-bolts and 7,776 nuts in Unit 1. Inspection of like Unit 2 baskets found zero broken bolts and 12 missing nuts.

To allow Unit 2 startup, 12 nuts were scavenged from Unit 1 and installed in Unit 2 and torqued to 16 plus or minus 2 ft. lbs. per direction from the licensee's Structural and Analytical Design Section in a letter dated November 2, 1990. Since then, Westinghouse issued a November 14, 1990 letter stating the torque should be 12 plus or minus 2 ft. lbs. The preliminary licensee analysis appeared to indicate that 6 out of 1,944 baskets with nuts torqued to 16 plus or minus 2 ft. lbs. is insignificant.

The licensee attempted to turn the nuts on 59 randomly selected Unit 2 ice baskets with a box end wrench to ensure that the U-bolts were not broken. The 59 randomly selected ice baskets represented a 95 percent confidence factor that there were no broken U-bolts. No problems were found.

To prevent further concerns, the licensee issued a procedure change to inspect the U-bolt nuts for proper torque prior to adding ice to the baskets.

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

10. <u>Management Meetings</u>

a. A management meeting, attended as indicated in Paragraph 1.a., was conducted in the NRC Region III offices on October 24, 1990. The purpose of the meeting was to discuss information relative to the recent Safety System Functional Inspection (SSFI) conducted by NRC during June and July, 1990; and also to discuss various licensee initiatives in the maintenance and maintenance-support areas.

   Among the topics presented by licensee representatives were:

   (1) SSFI design verification and other technical issues;

   (2) Future plans for SSFIs;

   (3) Conduct of maintenance during Unit 2 refueling;

   (4) Maintenance training plans;

   (5) Maintenance-Support program status;

(6) Long-range plans.

b. A management meeting, attended as indicated in Paragraph 1.b., was conducted at the D. C. Cook site on November 8, 1990. The purpose of the meeting was to discuss information relative to current plant status and to tour the plant.

Among the topics presented by the licensee staff were:

(1) Ice condenser U-bolt concern and steam dump valve problems;

(2) Outage Management objective and strategy;

(3) Plant maintenance program/implementation status;

(4) Current Unit 1 thimble tube wear status;

(5) Licensee submittals and NRC issuances.

11. <u>Management Interview (30703)</u>

The inspectors met with licensee representatives (denoted in Paragraph 1.c.) on November 16, 1990, to discuss the scope and findings of the inspection. In addition, the inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary.