U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Report Nos. 50-315/90025(DRP); 50-316/90025(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: November 14 through December 21, 1990

Inspectors: J. A. Isom

D. G. Passehl

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

01-08-91
DATE

Inspection Summary
Inspection From November 14 through December 21, 1990, (Report Nos. 50-315/90025 (DRP) and 50-316/90025(DRP))
Areas Inspected: Routine unannounced inspection by the resident inspectors of actions on previously identified items, plant operations, reactor trips, radiological controls, maintenance, surveillance, engineering and technical support, and security.
Results: No violations or deviations were identified in any of the 7 areas inspected. Additionally, no significant weaknesses or strengths in either the licensee's programs or implementation of these programs were observed during this period. The following is a summary of the major activities which occurred at the facility during this reporting period:.

a. Plant Operations:

During this reporting period, Unit 1 remained in a refueling outage. All major outage milestones were successfully achieved and no significant safety issues were encountered. At the end of the inspection period, Unit 1 was in the process of completing activities to place the Unit in MODE 4 on or about December 24, 1990.

Unit 2 was in MODE 1 at the beginning of the inspection period and experienced no major operational problems until the reactor tripped due to the West main feedwater pump trip on December 12, 1990. The cause of the West main feedwater pump trip was identified and corrected, and the Unit resumed MODE 1 operation on December 14, 1990. On December 15, 1990,

while in transition to MODE 4 to bypass a bad cell in the Unit 2 AB battery, Unit 2 tripped again. At the end of the inspection, the licensee identified the most probable cause for the trip to be the improper actuation of ATWS (Anticipated Transient Without Scram) Mitigation Safety Actuation Circuit (AMSAC). At the end of the inspection period, Unit 2 was in MODE 3 preparing for transition to MODE 1.

b. <u>Surveillance and Maintenance:</u>

Review and inspection of the surveillance and maintenance activities during this period indicated no significant weaknesses. In general, surveillance and maintenance activities were performed satisfactorily. However, the residents' investigations of the two Unit 2 reactor trips and the Unit 2 "CD" diesel air start problems identified instances in which improved communication and increased attention to detail may be warranted by the licensee.

DETAILS

1. Persons Present at:

   a. Systematic Assessment of Licensee Performance (SALP) Meeting - November 28, 1990.

   American Electric Power/Indiana Michigan Power

   D. H. Williams, Jr. Senior Executive Vice President, AEPSC
   M. P. Alexich, Vice President, Nuclear Operations, AEPSC
   T. O. Argenta, Assistant Vice President, Nuclear Engineering, AEPSC
   P. A. Barrett, Director, Quality Assurance, AEPSC
   S. J. Brewer, Manager, Nuclear Safety and Licensing (NS&L), AEPSC
   D. A. Kruer, Manager, Quality Assurance Engineering, AEPSC
   J. F. Kurgan, Manager, Nuclear Operating Support, AEPSC
   M. S. Ackerman, Licensing Engineer, NS&L, AEPSC
   M. W. Evarts, Nuclear Maintenance Support, AEPSC
   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

   A number of other licensee personnel were also in attendance.

   Nuclear Regulatory Commission (NRC)

   NRC Headquarters

   J. G. Partlow, Associate Director for Projects.
   B. A. Boger, Assistant Director for Region I Reactors
   R. C. Pierson, Director Project Directorate III-I
   T. G. Colburn, Project Manager, D. C. Cook
   R. J. Stransky, Project Manager, Big Rock Point

   NRC Region III

   A. B. Davis, Regional Administrator
   H. J. Miller, Director, Division of Reactor Projects
   H. B. Clayton, Branch Chief, Projects Branch 2
   M A. Ring, Branch Chief, Engineering Branch
   B. L. Jorgensen, Section Chief, Projects 2A
   E. R. Schweibinz, Senior Project Engineer
   J. A. Isom, Senior Resident Inspector
   D. G. Passehl, Resident Inspector

   b. Management Meeting (December 10, 1990)

   Licensee Personnel

   D. H. Williams, Jr., Senior Executive Vice President, AEPSC
   M. P. Alexich, Vice President, Nuclear Operations, AEPSC
   T. O. Argenta, Assistant Vice President, Nuclear Engineering, AEPSC

S. J. Brewer, Manager, NS&L, AEPSC
N. Ruccia, Manager, Structural and Analytical Design, AEPSC
S. R. Sharma, Licensing Engineer, NS&L, AEPSC
M. S. Ackerman, Licensing Engineer, NS&L, AEPSC
M. W. Evarts, Nuclear Maintenance Support, AEPSC
J. B. Kingseed, Licensing Engineer, NS&L, AEPSC
A. A. Blind, Plant Manager
K. R. Baker, Assistant Plant Manager, Production
J. R. Rutkowski, Assistant Plant Manager, Technical Support
L. S. Gibson, Assistant Plant Manager, Projects
T. P. Beilman, Maintenance Superintendent
J. R. Sampson, Operations Superintendent

NRC Headquarters

J. R. Curtiss, Commissioner
K. A. Connaughton, Commissioner's Technical Assistant

NRC Region III

C. J. Paperiello, Deputy Regional Administrator, RIII
J. A. Isom, Senior Resident Inspector
D. G. Passehl, Resident Inspector

c. Inspection (November 14 through December 21, 1990)

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

The inspectors 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 resident inspectors' exit on December 21, 1990.

2. Actions on Previously Identified Items (92701, 92702)

a. (Closed) Open Item (316/90022-02): This open item concerned the licensee's use of 10 gallons per minute (gpm) leakage acceptance value for pressure isolation check valves (PICVs) which were tested in pairs, when PICVs tested individually had a leakage acceptance

value of 5 gpm. The resident inspectors questioned the usage of the 10 gpm leakage acceptance value as potentially leading to a condition in which an individual PICV leakrate could exceed 5 gpm without a corrective action being required by the surveillance procedure. The resident inspectors closed this open item based on the fact that there was no regulatory requirement which prohibited the use of the 10 gpm leakage rate acceptance value, and also based on the licensee's past history of performing corrective maintenance to repair seat leakages associated with the PICVs.

The resident inspectors' review of the Technical Specifications, other licensee commitments, and interviews with the licensee's engineering staff found that there were no specific regulatory requirements for the PICVs which were tested in pairs to meet either the 5 or the 10 gpm leakage acceptance criteria. However, the licensee had established the 10 gpm acceptance criteria to ensure that these PICVs would not leak excessively without being noticed. Furthermore, the residents were informed that the 10 gpm leakage rate was well within the capacity of the system's relief valves and is included in the recently approved second 10-year Inservice Testing Program. Additionally, the resident inspectors were informed by the licensee that in the past, all minor leaks associated with the PICVs were repaired. The residents' review of past surveillance tests, from 1985 to the present, found that the licensee had made repairs to all PICVs which had been found to be leaking.

b. NRC Region III Management has reviewed the existing open items for the D.C.Cook station and has determined that the following open items will be closed administratively based on their age and their relative safety significance as compared to other emerging priority issues:

315/85003-BB (Bulletin)	316/85003-BB (Bulletin)
315/87023-02	316/87023-02
315/88028-04	316/88032-04
315/88028-06	316/88032-06
315/89022-01	316/89022-01
315/89022-02	316/89022-02

The licensee is reminded that commitments directly relating to these open items are the responsibility of the licensee and should be met as committed. NRC Region III will periodically review licensee's actions associated with the administratively closed open items on a sampling basis.

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

3. <u>Operational Safety Verification (71707, 71710, 42700)</u>

Plant startup, steady power operation, plant shutdown, and system(s) lineup and operation were observed as conducted in the plant and main control rooms. The performance of licensed Reactor Operators and Senior Reactor Operators, Shift Technical Advisors, and auxiliary equipment operators in the areas of procedure use and adherence, records and logs, communications, shift/duty turnover, and the degree of professionalism of control room activities was observed and evaluated. The Plant Manager, Assistant Plant Manager-Production, and the Operations Superintendent were well-informed on the overall status of the plant. Additionally, the residents performed evaluation of the licensee's corrective actions, and responses to off-normal conditions or events. The evaluations included compliance with any reporting requirements.

a. During this reporting period, Unit 1 remained in a refueling outage. All major outage milestones were successfully achieved and no significant safety issues occurred as a result of activities associated with the Unit 1 outage. At the end of the inspection period, Unit 1 was in the process of completing activities in order to place the Unit in MODE 4 on or about December 24, 1990.

b. Unit 2 experienced no major operational problems until the reactor tripped on December 12, 1990. Unit 2 tripped on low feedwater flow coincident with low steam generator water level caused by a loss of the west main feed pump (MFP). At the time of the trip, the Unit was operating at 100 percent power and the operators had no indication of any abnormalities associated with the West MFP. Once the problem with the West MFP was identified and corrected, Unit 2 was returned to MODE 1 on December 14, 1990. On December 15, 1990, while in transition to MODE 4 to bypass a bad cell in the Unit 2 "AB" battery, Unit 2 tripped again. At the end of the inspection, the licensee identified the most probable cause for the trip to be the improper actuation of AMSAC during the power reduction process to MODE 4. At the end of the inspection period, Unit 2 was in MODE 3 preparing for transition to MODE 1.

c. A small amount of backleakage from the reactor coolant system past the pressure isolation check valves continued to slowly pressurize the North and South Safety Injection (SI) header during this inspection period. More details of the pressurization of the SI headers were discussed in inspection report No. 50-315/90023(DRP); 50-316/90023(DRP). However, the resident inspectors' interviews with the operators indicated that the rate of SI header pressurization appeared to have diminished partly because of the small leak which had developed past the valve on the SI discharge header, normally used to release the pressure. The leakage past this valve is presently being collected in a portable radioactive storage canister which is directed to the floor drain in the SI pump room. Consequently, the possibility of contamination of the SI pump room from this valve leak has been minimized. The licensee has also initiated a design change request to provide a permanent vent path for the SI header.

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

4. <u>Reactor Trips(s) or ESF Actuations (93702)</u>

a. At 3:19 A.M., December 12, 1990, Unit 2 tripped from a low feedwater flow coincident with low steam generator level caused by a loss of the west main feed pump (MFP). At the time of the trip, the Unit was operating at 100 percent power and the operators had no indication of any abnormalities associated with the West MFP. Consequently, the first indication of a problem with the West MFP occurred after it tripped and the annunciator, "West FPT (Feed Pump Turbine) Thrust Brg Position Trip," was illuminated in the control room. Although the operator immediately reduced steam flow to the main turbines, Unit 2 tripped approximately 40 seconds later on low feedwater flow coincident with low steam generator water level.

Discussion of the transient with the operators indicated that loss of one MFP with the Unit operating at 100 percent power would ordinarily lead to a reactor trip. This is due to lowering of steam generator water level, caused by feedwater to steam flow mismatch in conjunction with the shrink in steam generator water level as power is reduced. This is too rapid a transient for the operator to mitigate and stop once the condition is recognized and appropriate actions are taken. The unit trip occurs once the low steam generator water level setpoint is reached after losing one of the two MFPs. Additionally, the residents were informed that the rate of power reduction must not be too rapid in order to minimize the magnitude of the shrink associated with the steam generator water level while at the same time not too slow in order to minimize the time during which steam flow is greater than feedwater flow. The investigation by the licensee found that the cause of the MFP trip was improper operation of the shaft position indicator trip contacts. The shaft position indicator protects the turbine from dangerous axial displacement of the turbine rotor. The licensee made all required notifications and the safety systems functioned satisfactorily after the Unit trip. The resident's review related to the cause of the West MFP trip is discussed in section 5 of this report.

b. At about 3 p.m. on December 15, 1990, Unit 2 reactor tripped from about 35 percent power level due to a trip of the main turbine. At the time of the reactor trip, the operators were performing a 25 percent per hour power reduction to MODE 4 so that maintenance could be performed on the inoperable Unit 2 "AB" battery. The Unit 2 "AB" battery was declared inoperable the morning of December 15th because cell number 90 voltage reading indicated less than the original acceptance voltage by more than .05 volts. The licensee was unable to raise the voltage of the affected cell and therefore was required by Technical Specifications to be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. During the power reduction, Unit 2 experienced a turbine trip. There was no readily apparent cause for the trip. Based on the reactor operator's observation that the "AMSAC initiated" alarm had been illuminated earlier than he would have expected and based on the lack of other apparent causes for the turbine trip, the licensee performed a post trip review to determine whether AMSAC (ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuit) could have initiated the turbine trip.

The licensee's review found that a recent recalibration of the feedwater flow bistable trip used an erroneous voltage value. The AMSAC feedwater flow trip occurred at about 35 percent rather than 25 percent feedwater flow. Consequently, the licensee concluded that an erroneous feedwater flow bistable trip setpoint coincident with an armed "C20 Permissive" circuit was the most likely cause of the main turbine trip. "C20 Permissive" circuit is armed when both turbine impulse pressure transmitters indicate greater than 40 percent reactor power. This configures the AMSAC system to trip the main turbine when 3 of 4 low feedwater flow conditions are satisfied. Also, the "C20 Permissive circuit" stays armed for about 360 seconds after either of the turbine impulse pressure transmitters indicates equivalent to less than 40 percent power. Therefore, it would be possible to trip the main turbine due to low feed flow from the AMSAC system. The licensee made all required notifications and the safety systems functioned satisfactorily after the Unit trip.

Unit 2 "AB" as battery cell number 90 was bypassed. Additionally, cell number 104 was bypassed because its cell voltage was found to be marginally acceptable. The resident inspectors' review of the erroneous voltage value used in the "Turbine Trip AMSAC Calibration" procedure is discussed in section 6 of this inspection report.

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

5. Maintenance (62703, 42700)

Corrective and/or preventive maintenance activities were reviewed or inspected by the resident inspectors. Mechanical, electrical, and instrument and control group maintenance activities were included as available.

The focus of the inspection was to ensure the maintenance activities reviewed were conducted in accordance with approved procedures, regulatory guides, 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 inspected and/or reviewed:

a. Job Order B21659, "Replace valve and actuator for 2-XRV-226." This job order was written in response to the failed Unit 2 Emergency Diesel Generator (DG) surveillance discussed in paragraph 6 and involved repair to the Unit 2 "CD" DG air start valves. The inspectors' review of the job order package and interviews with the system engineer found that the corrective maintenance on the DG was performed satisfactorily and the DG was properly returned to OPERABLE status within the required time as specified by the T. S. However, the residents noted and were concerned with the inadvertent modification that had occurred to a safety related system during the replacement of some bent air piping that, in conjunction with the loose fitting to one of the two air start pilot valves, caused the inoperability of the Unit 2 "CD" DG.

The diesel air start system consists of two air receivers which supply air to the the DG through two separate sets of piping and air-operated air start valves. The air start piping is also cross-connected downstream of the air start valves. Unit 2 "CD" air-operated air start valves are 2-XRV-226 for one train and 2-XRV-227 for the other train.

The resident inspectors' investigation into the inoperability of the Unit 2 "CD" diesel identified two unrelated causes which disabled the Unit 2 "CD" DG air start system. First, one train of air start system was inadvertently disabled when pilot valve exhaust ports associated with air-operated air start valve, 2-XRV-227, was plugged by the "material condition crew." Consequently, 2-XRV-227 failed to open when the diesel start signal was initiated. Secondly, the other redundant air-operated air start valve, 2-XRV-226, failed to open due to a loose fitting on the air line to its pilot valve.

The licensee corrective maintenance on the Unit 2 "CD" DG identified and successfully corrected the two material deficiencies associated with the diesel air start system. The exhaust port plugs were removed, the pilot valves associated with 2-XRV-226 replaced, and the loose fitting repaired. Additionally, the licensee performed two successful operability surveillance tests to verify that both air start trains could independently start the DG.

The investigation into the cause for the plugging of the 2-XRV-227 exhaust ports determined that a "material condition crew" had plugged the threaded exhaust ports. The "material condition crew" had been replacing some bent air tubing in the vicinity of 2-XRV-227 and believed that the unplugged exhaust ports were a material deficiency which needed to be corrected. The crew members were counselled by the maintenance supervisor not to make changes to equipment unless proper reviews have been performed.

b. Job Order 9608 "Investigate Reason and Correct Cause of West Main Feed Pump Trip on 12-12-90 at 0319 hours." Resident inspectors reviewed the job order, and interviewed technicians involved in the troubleshooting. They found that the licensee's review successfully identified the cause for the MFP trip. The corrective maintenance, as detailed in the vendor's manual, was performed satisfactorily by the I&C technicians.

The investigation by the licensee found the cause of the West MFP trip to be misadjusted trip and alarm contacts associated with the MFP turbine shaft position indicator (referred to in the Brown Boveri Vendor's manual as shaft position supervisor). After the Unit tripped, the shaft position indicator on the West MFP turbine was found with the trip signal present. The residents' interviews with the I&C technicians revealed that the West MFP turbine thrust bearing trip contacts initiated before the West MFP turbine thrust bearing warning contacts. The "as found condition" of the West MFP turbine thrust bearing trip contact was consistent with the operators' observation that at the time of the Unit 2 trip, the first indication of any problem with the West MFP occurred after it tripped.

The MFP is coupled to and driven by the MFP turbine. Consequently, a trip of the MFP turbine will result in a MFP trip. The shaft position indicator protects the MFP turbine from dangerous axial displacement of the rotor. In the event the MFP turbine shaft displaces 0.016 inch axially in relation to the thrust bearing, a warning light, "West FPT (Feed Pump Turbine) Thrust Brg Position ABN," is illuminated in the control room. In the event the MFP turbine shaft displacement reaches 0.032 inches, the shaft position indicator module shuts a second set of contacts, the West MFP turbine is tripped and a "West FPT Thrust Brg Position Trip" light is illuminated in the control room.

The technicians reset both the warning and trip contacts associated with the West MFP shaft position indicator module to the required setpoints of 0.016 and 0.032 inches respectively. The resident inspectors were informed by the technicians involved in the investigation that the "as found" alarm and trip readings associated with the West MFP shaft position indication could not be recorded because the trip contacts were shut even with the module removed from the MFP housing and indicating 0.00 inches of displacement. Additionally, because of this problem, warning and trip contacts for the East MFP shaft position indicator module were checked for proper setpoints. The trip setpoint was found to be greater than the required 0.032 inches setpoint and the warning light was found to initiate at .014 inches. Both the trip and warning light associated with the East MFP were adjusted to within required tolerances.

Because the shaft position module for the West MFP was new and had just been replaced, and because the vendor representative from the Brown Boveri Company had checked it for proper operation during Unit 2 startup, the resident inspectors requested copies of any maintenance job orders associated with the shaft position indicator module within the past several weeks. The residents found that technicians had performed corrective maintenance on the West FPT on November 18, 1990, to correct a similar problem with the West FPT. The job order described the problem with the West MFP to be:

> West FPT Thrust Brg. Position Abnormal alarm is alarming in and out. Shaft position reading locally is "0." Oil and bearing temperatures are normal.

Troubleshooting by the I&C technicians found that one of the alarm switch contacts was coming in around 0.05 mm (0.002 inch) vice the prescribed setpoint of 0.4mm (0.016 inch). The technicians adjusted the switch #2 to 0.4mm and verified that the alarm remained clear. The review of the maintenance work order, interviews with the I&C technician, and review of the vendor's manual used to reset the alarm and trip switches indicated that the corrective maintenance appeared to have been performed correctly and the work performed on November 18 did not appear to have contributed to the December 12, 1990, trip of the West MFP.

Additionally, because the licensee had just completed the reliability centered maintenance (RCM) review of the feedwater system, the inspectors performed a limited review of the results to determine whether any preventive maintenance associated with the shaft position indicator system was identified and recommended for possible incorporation into the licensee's preventive maintenance program. The RCM on the feedwater system appeared to be very comprehensive and did identify the MFP turbine thrust bearing wear trip auxiliary relay for recommended visual inspection and cleaning if required. However, the residents were informed by the licensee that the verification of the proper thrust bearing trip setpoints into the preventive maintenance program was not recommended because they could not be tested. The resident inspectors' review of the vendor manual indicated that although the warning and trip contacts associated with the MFP shaft position indicator cannot be tested in place, it can be removed from the MFP housing so that both the alarm and trip contact close and open settings can be verified. The licensee is considering a possible incorporation of verification of the proper initiation of the warning and trip signals from the shaft position indication module, into their preventive maintenance program to minimize the possibility of a reactor trip caused by a spurious MFP trip.

c. During one of the routine inspector tours of the Auxiliary Building, nine job order tags were noted attached to the entrances to the Seal Water Injection Filter (SWIF) rooms. The inspectors reviewed the maintenance activities associated with the nine job order tags to determine their status, the type of maintenance activities to be performed, and to determine their safety significance. The residents' review found that none of the maintenance activities associated with the job order tags were of a safety concern. (The maintenance activities were, for the most part, to correct minor valve leaks and hardware deficiencies.)

The inspector noted that the licensee's job tracking system appeared to be generally accurate in determining the status of outstanding work items in the plant. However, the inspectors identified a minor problem in that even though the maintenance activities associated with 3 of the 9 job order tags had been completed, these tags had not yet been removed. The jobs that were completed with the tags in place were Nos. A002772, B016554, and B016800. The jobs addressed packing leak problems on two SWIF shutoff valves and a stem and handwheel replacement on a vent valve. The jobs were completed about September and October, 1990.

Additionally, the inspector noted repeated maintenance activities associated with Job Order B016291, "Large amount of wet boric acid on valve and stem area." This job was written December 4, 1990 to address an apparent packing leak on valve 2-CS-311N (reactor coolant pump North seal water injection filter outlet shutoff). This valve was worked at least three times in 1990 to address minor external leakage problems. Discussion with the members of the Maintenance Department indicated that they were unaware of the number of times this valve had been worked in the past and of the fact that all these various attempts to repair the valve (such as changing packing material) were unsuccessful. Based on discussions with the residents, the licensee retrieved the job history on the valve to evaluate past problems and stated that a cause for the apparent rework would be investigated.

d. A maintenance team follow up inspection was conducted at the site beginning December 3, 1990 and ending December 7, 1990. The inspection and results of the inspection will be documented in report 50-315/90024(DRS); 50-316/90024(DRS).

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

6. Surveillance (61726, 42700)

The inspector reviewed Technical Specifications required surveillance testing as described below and verified that testing was performed in accordance with procedures, test instrumentation used was calibrated, and Limiting Conditions for Operation were met. Additionally, the inspectors verified that deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The following activities were inspected:

a. **2 IHP 6030 IMP.428, "Turbine Trip AMSAC Calibration." The resident inspectors reviewed various licensee's documents related to the calibration and setting of AMSAC low feedwater flow bistable trip setpoint to determine the cause of the reactor trip on December 15, 1990. The residents performed a limited review of the procedures, "Control of Plant Instrument Setpoint Information" PMSO.105, Rev. 3, 01/15/1990 and "Turbine Trip AMSAC Calibration" **2 IHP 6030 IMP.428 Rev. 1, 07/02/1990. Design calculations, 1-ECP-F2-11 and 2-ECP-F2-11, performed to obtain revised new voltage values for low feedwater flow bistable trips, and other related memos and procedures. Additionally, interviews were conducted with the members of the licensee's engineering staff who had revised the AMSAC calibration procedure and those individuals who had performed investigation of the reactor trip. The residents found that the erroneous low feedwater bistable settings found in the AMSAC circuit were caused by the site engineering staff improperly incorporating revised voltages for the low feedwater flow bistable trips. Additionally, the residents noted that an ineffective review of the "Turbine Trip AMSAC Calibration" procedure had prevented the error from being identified. The residents did not identify any programmatic weakness in the licensee's setpoint control or procedural change programs.

"Turbine Trip AMSAC Calibration" procedures, **2 IHP 6030 IMP.428 Rev. 1, 07/02/1990 and **1 IHP 6030 IMP.328 Rev. 1, 07/16/1990, were revised in part to change the low feed flow bistable setpoints to reflect the actual rather than design 25 percent feed flow voltage values. The corporate engineering department recalculated the low feedwater flow bistable trip setpoint voltage for the AMSAC spec 200 alarm cards using actual 25 percent flows for both Units. When these new voltage values were incorporated into the Unit 1 and 2

"Turbine Trip AMSAC Calibration" procedures, plant engineering staff incorrectly used the voltage values referenced in the corporate engineering calculations. Although the error was later determined to be conservative, it caused an unnecessary reactor trip of Unit 2. The licensee changed the "Turbine Trip AMSAC Calibration" procedures for Unit 2 and has recalibrated the Unit 2 low feedwater flow bistable trip. Also, the licensee changed the Unit 1 "Turbine AMSAC Calibration" procedure and is planning to recalibrate the Unit 1 low feedwater flow bistable trip before Unit 1 restart.

1-ECP-F2-11 and 2-ECP-F2-11, which are engineering calculation documents, recalculated the low feedwater flow setpoints for Unit 1 and Unit 2 AMSAC spec 200 process alarm cards. The ECPs determined that the low feedwater flow setpoint for Foxboro spec 200 process alarm card was 2.201 Vdc decreasing for Unit 1 and 2.288 Vdc for Unit 2. When these newly revised low feedwater flow bistable trip setpoints were incorporated into the "Turbine Trip AMSAC Calibration" procedures, 10 percent of these voltage values were used as the desired bistable setpoint trips. A different set of voltages had to be calculated by the plant engineers for use in the AMSAC calibration procedure because the revised voltages given in the ECPs were at the Foxboro spec 200 process alarm cards, which are not where voltages are measured when setting the low feedwater flow bistable trips during the "Turbine Trip AMSAC Calibration" procedure. The residents' discussions with the licensee's engineers could not determine the justification for use of the 10 percent ratio other than some unjustified assumptions were made with respect to the AMSAC circuit without performing a more detailed review. The residents' discussions with the technicians involved in the post trip investigation indicated that translation of the voltages given in the ECPs into the calibration procedure was uncomplicated for individuals familiar with the AMSAC circuit. After the trip, new low feedwater flow bistable trip voltage checks for the calibration procedures were performed and proper voltages were found to be lower than the previously used 10 percent of the ECP voltages at the Foxboro spec 200 process alarm card.

b. ** 2-OHP 4030.STP.027CD, "CD Diesel Generator Operability Test (Train A)." The test was run on December 11, 1990, to prove operability of 2 "CD" Diesel Generator (DG) after completion of pre-planned maintenance activities for which the DG had been declared INOPERABLE. The inspector's review of the operability tests found that the surveillance was attempted four times with the first two attempts resulting in incomplete DG starts because of problems with the starting air system. The second two attempts were successful and were necessary to prove operability of both trains of air starting system to the DG. The review of the completed surveillance procedure identified no major discrepancies with either the documentation or the surveillance test results and the procedure appeared to adequately demonstrate the operability of the DG.

However, the resident inspector's review of the documentation associated with this surveillance activity did note a minor procedural discrepancy with one of the surveillances. Section 9.1, which is used for documenting problem areas, was left blank. This section is normally used to document the Job Order number requested, and the time and date of the Condition Report for surveillances which are found to be unsatisfactory. Additionally, the inspector's review of the surveillance procedure noted that the current DG testing method could be improved to enhance earlier detection of problems with the DG air start system. Currently, the DG surveillance procedure is written such that, every third month, the operability of the DG air start system is verified by using both air trains (normal system configuration). Consequently, a problem with one of the air trains during this 3rd month would remain undetected until that air train was tested alone. The residents' discussion with the licensee indicated that the primary reason for both trains being tested in parallel during the third month was not based on technical merit, but rather based on the fact that the requirements of the IST (Inservice Test) program for the air start system were satisfied after two months of tests and because there have not been problems with the diesel air start system in the past. In the worst case, using the current testing sequence, a problem with one train of air start system could remain undetected for three months. On the other hand, if each train of a start system was tested every other month, problems with one train of the air start system would remain undetected for only two months. At the exit, the licensee agreed to review the DG testing method for possible change in the future.

c. **12 THP 4030 STP.206.1, "Surveillance Test Procedure - Electric Hydrogen Recombiner." The procedure was performed on the Unit 2 No. 1 Hydrogen Recombiner to satisfy the 18 month operability requirement of the Technical Specifications. The surveillance procedure verified acceptable insulation resistances for the electrical cables, and that the heater sheath reached proper temperature within the required time. The inspector observed the surveillance and noted that the test engineer was knowledgeable about the equipment and its operation. The procedure was clear and data was properly documented. No problems were noted with procedure performance and all acceptance criteria were met.

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

7. Engineering and Technical Support

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

a. During this inspection period the licensee completed the examination of the Unit 1 in-core flux thimble tubes. After one cycle of operation some amount of wear was found on 56 of the 57 tubes. More specifically, 19 tubes with wall losses estimated at 40 percent or greater were identified. Three tubes showed wall losses in the order of 60 percent. The maximum wall loss, about 64 percent, was indicated on one tube. As was noted for the Unit 2 tubes (see NRC Inspection Report 50-315/90023;50-316/90023), the worst wear, on most of the tubes, was at a location corresponding to the fuel assembly bottom nozzle.

During the current Unit 1 outage, the licensee repositioned 29 tubes showing wear in excess of 30 percent to a location free of wear. No tubes were replaced as indications for all tubes were below the threshold values provided by Westinghouse. The licensee has committed to provide NRC with the results of their root cause analysis and long term recommendations, both of which would be provided in early 1991.

b. The information relative to the number of steam generator (SG) tubes plugged as a result of eddy current examination activities was also noted. Inspection of Unit 1 steam generators included 100 percent of all previously nonplugged tubes. The total number of tubes examined in each steam generator was 3208 in SG-11, 3240 in SG-12, 3246 in SG-13, and 3221 in SG-14.

   Additional tubes plugged this outage per steam generator were 64 in SG-11, 18 in SG-12, 57 in SG-13, and 31 in SG-14. Of the total number of tubes plugged, 19 were plugged based on Technical Specification requirements (greater than or equal to 40 percent tube wall degradation). This included 5 tubes in SG-11, 8 tubes in SG-12, 5 tubes in SG-13, and 1 tube in SG-14.

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

8. Radiological Controls (71707)

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

No significant radiological deficiencies were noted by the residents during the tour of the auxiliary or containment building. During the tour of Unit 1 containment, there were indications of increased management attention with respect to proper wearing of dosimetry and anti-contamination clothing by plant personnel. Signs were posted to indicate the proper order of wearing and removal of anti-contamination clothing, a pre-recorded video tape demonstrated the proper use of anti-contamination clothing, and RP technicians monitored plant individuals to ensure good radiological practices were being followed.

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

9. 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 conducted with security force members.

On December 13, 1990, a "Fitness-for-Duty" concern was identified when an ice condenser crew foreman attempted to enter the Protected Area with a measured blood alcohol content (BAC) of 0.041 percent. A security guard detected the odor of intoxicants upon the person, who was reporting for work that evening. The individual was stopped before access was granted into the Protected and Vital Areas and the individual was terminated upon positive confirmation of the BAC. A full description of the event was given to the NRC Region III Security staff for follow-up.

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

10. <u>Management Meeting</u>

a. A management meeting, attended as indicated in Paragraph 1.a., was conducted at the D. C. Cook site (Visitors Center) on November 28, 1990. The purpose of the meeting was to formally present the SALP 9 report (NRC Inspection Report No. 315/90001; 316/90001) to the licensee.

b. A management meeting, attended as indicated in Paragraph 2.a., was conducted at the D. C. Cook site on December 10, 1990. The purpose of the meeting was to discuss various licensee initiatives, and to tour the plant.

Among the topics presented by the licensee staff were:

(1) 1990 Accomplishments and 1991 Goals and Objectives.
(2) Self-Initiated Inspections.
(3) Individual Plant Examination Overview.
(4) Spare Parts Program.
(5) Large and Small Bore Piping Program.

11. <u>Management Interview</u>

The inspectors met with licensee representatives (denoted in Paragraph 1) on December 21, 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.