U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Report Nos. 50-315/90010(DRP); 50-316/90010(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: April 25 through June 5, 1990

Inspectors: B. L. Jorgensen

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Projects Section 2A

6/15/90
DATE

Inspection Summary

Inspection on April 25 through June 5, 1990 (Report Nos. 50-315/90010(DRP); 50-316/90010(DRP))
Areas Inspected: Routine unannounced inspection by resident and regional inspectors of: actions on previously identified items; plant operations; maintenance; surveillance; engineering and technical support; emergency preparedness; and, licensee self-assessment. Special unannounced inspection by resident and regional inspectors of circumstances surrounding Emergency Plan "Unusual Event" and "Alert" declarations following a switchyard breaker failure on May 24, 1990. The following Safety Issues Management System (SIMS) items were reviewed, with the indicated results: (Closed); TI2515/94, Multi-Plant Action Item B-03, "PWR Moderator Dilution," (Paragraph 6.b).
Results: Of the eight areas inspected, no violations or deviations were identified in six areas. Two violations were identified (non-cited Level V - minor containment cleanliness discrepancies - Paragraph 3.c; Level IV - failure to correct known maintenance procedure discrepancies - Paragraph 4.a) with one in each of the remaining two areas. The inspection disclosed no previously unremarked weaknesses or strengths in the licensee's activities in the inspected areas. No new Open Items and/or Unresolved Items were identified.

DETAILS

1. Persons Contacted

*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
*S. Wolf, Quality Assurance Senior Auditor
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 June 6, 1990.

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

a. (Closed) Open Item (315/87026-06; 316/87026-08): stored material protection and preventive maintenance to meet ANSI, plant and vendor specifications. The licensee has reorganized and upgraded storage areas for safety-related supplies. Preventive maintenance on stored material has been enhanced. Storage and preventive maintenance have not yet achieved all ANSI and vendor recommendations, but the remaining incomplete actions are non-regulatory and no longer warrant tracking via an "Open Item."

b. (Closed) Open Item (315/87026-07; 316/87026-09): evaluate apparently excessive reliance on field changes to install plant modifications. The subject evaluation was part of an overall assessment of the design control process which the licensee contracted an independent auditor (CYGNA Energy Services) to perform in late 1989. Some weaknesses were confirmed in the process for planning and scoping design changes, which could contribute to the need for field adjustments. A "CYGNA Audit Response Group" was chartered and, in January, 1990, responded to these (and other) weaknesses with an issue-specific action plan and schedule, which was essentially completed during the inspection period.

c. (Closed) Open Item Nos. 315/88006-01; 316/88007-01: this item, which addressed the representativeness of the licensee's new onsite meteorological program, was reviewed and determined to be adequate in Inspection Report Nos. 315/89027(DRSS); 316/89027(DRSS). This item is closed.

d. (Closed) Violation (315/89009-01): use of guidelines vice reviewed and approved procedures for maintenance on 4KV breakers and main steam stop valve hydraulic system. The licensee's letter (AEP:NRC:1090B) dated May 11, 1989, stated his belief the technical specification requirements for procedures were met in the cited examples. NRC disagrees.

The referenced licensee letter however, did describe corrective actions to avoid further violation. This consisted primarily of clarifying language in procedure PMI-2290, "Job Orders," to establish a three-tiered approach to the degree of formality in written controls for maintenance activities. Activities requiring no written controls, and those requiring formal, detailed, reviewed and approved written procedures, are at the opposite ends of the three tiers. In between, PMI-2290, at Section 4.3.6, now provides rules for when and how a "Maintenance Plan" may be utilized.

The inspector reviewed the criteria for use of "Maintenance Plans" and found them appropriate. The first rule is that they cannot substitute for procedures required by PMI-2010, "Plant Manager and Department Head Instructions, Procedures and Associated Indexes," and the second rule is they cannot change such procedures. Remaining rules cover accuracy, traceability, cross-referencing, deviations, documentation, etc.

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

3. 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 as applicable.

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, made frequent visits to the control rooms, 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. Reviews of surveillance, equipment condition, and tagout logs were conducted. Proper return to service of selected components was verified.

a. Both units operated routinely at 100-percent power early in the inspection period. Unit 1 was brought to 70-percent power on April 29, 1990 for core life extension beyond completion of the Unit 2 refueling outage at the end of August, 1990. Unit 2 reactor power was likewise decreased to 85-percent on May 1, 1990 to extend core life to match the scheduled date for that unit's refueling. An event associated with Unit 1 (Paragraph 3.b) caused a brief power reduction to 8-percent on May 9, 1990. Both units came back to 100-percent power at the request of the System Load Dispatcher for a brief period (May 17-19, 1990) because of problems at other outside generation units which affected system capacity. An Emergency Plan "Unusual Event" and "Alert" were consecutively declared on May 24, 1990 because of an electrical fault in the 345KV switchyard (Paragraphs 7 and 9). The units continued to operate, but Unit 1 was briefly brought to 60-percent power to enhance system stability during needed breaker switching.

b. On May 8, 1990, an operator performing a surveillance test on a hydrogen recombiner started a containment recirculation fan (ESF component) by mistake. This caused the lower ice condenser inlet doors to open, and ice bed temperatures increased above the technical specification limit. The unit was placed in a 48-hour Limiting Condition for Operation (LCO) at 3:55 p.m. on May 8, almost simultaneous with receipt of the "inlet doors open" alarm in the control room. The LCO required ice bed temperatures to be less than 27 degrees Fahrenheit in 48-hours; otherwise, commence a unit shutdown.

The licensee attempted various changes in the internal containment air circulation lineup throughout the next several hours in an unsuccessful effort to close the doors while remaining at 70 percent power. Starting at 5:16 a.m. on May 9, reactor power was reduced to 8-percent to greatly reduce neutron radiation and allow personnel entry to close the doors manually.

Manual closure was accomplished around 1:00 p.m. on May 9. Several high-level management discussions ensued pertaining to ice quantity lost and ice bed temperatures. One airspace temperature below the ice reached almost 50-degrees Fahrenheit for a short time. About 24 hours still remained before expiration of the LCO time clock.

Based on observation by ice crew personnel and mathematical estimates, the licensee concluded that approximately 550 pounds of ice was lost (out of roughly 2.7 million pounds) and that the ice bed remained capable of performing its intended safety function.

The licensee then opted to increase reactor power to a stable 50-percent and maximize operation of various containment air handling units and chillers. All ice condenser ice bed temperatures fell below 27 degrees Fahrenheit by 1:25 p.m. on May 10, about 3.5 hours before LCO time clock expiration. Reactor power was then

restored to the 70-percent power level in effect before the incident began.

c. Facility tours included a detailed tour of the Unit 1 upper containment on May 16, 1990. During this tour, the following loose items were found lying on various structural beams around the upper catwalk: one weld rod; two felt-tip markers; five nails; and, one small plastic handle/wheel. All these items were removed to the airlock upon completion of the tour and licensee management was notified.

Licensee procedure 01-OHP 4030.001.002, "Containment Closeout Inspection Tour" specifies at Step 12 of Attachment 1 that "...All trash and loose debris have been removed from all areas of upper containment and ice condenser." The conditions found on May 16, 1990 did not satisfy this specification. This procedure is mandatory via Technical Specification 6.8.1.c, because it implements, in part, Unit 1 Technical Specification surveillance requirement 4.5.2.c, to perform "...a visual inspection which verifies that no loose debris...is present in the containment which could be transported to the containment sump and cause restriction of the (ECCS) pump suctions..."

Failure to adequately implement the procedure and verify all loose debris was removed is considered a violation of Technical Specification 6.8.1.c. (Violation 315/90010-01).

The specific location, quantity and type of items were assessed. Concerning location, they were remote from the sumps (in lower containment); they were, in fact, far from the upper containment drains to lower containment. Typically, they were higher than the highest containment spray ring but one. The quantity was small - a single handfull. The weld rod and nails were considered incapable of being "flushed" to the sump area. Thus, the specific significance of this finding was small.

The licensee had a previous history of excellent containment cleanliness closeout inspection and control. Therefore, the current findings were not considered programmatic, but were an isolated case. The licensee initiated appropriate corrective action via Problem Report 90-0576, including repeat detailed walkdowns in both units' upper containments. No significant additional findings resulted.

The inspector concluded this violation was a Severity Level V violation which satisfies the criteria specified in Section V.A of the NRC Enforcement Policy (10 CFR 2 Appendix C); therefore, no Notice of Violation will be issued.

d. During a tour on May 17, 1990, the inspector noted a couple of loops of clear plastic tubing of about 1-inch diameter hung over a pair of auxiliary feedwater (AFW) recirculation flow instruments in the AFW hallway. The tubing was labeled for emergency use in the event of

loss of condensate to the AFW pumps, so it belonged in the area, but hanging it from instrumentation was considered inappropriate. This was passed along to plant management. A subsequent tour on May 21 found the tubing staged in a labeled, wall-mounted canvas bag which appeared entirely appropriate.

e. The inspector performed a specific review of compliance to "cross-train" segregation requirements on May 21, 1990, when multiple components were considered "inoperable" in each unit. For Unit 1 the components were the 1CD emergency diesel generator (routine maintenance and calibration) and the East auxiliary feedwater (AFW) pump (room door unsecured). The Unit 2 components were the East essential service water pump (breaker preventive maintenance) and the East AFW pump (room door). Both Unit 1 items were East/Green train components. Both Unit 2 items were also East/Green train components. Compliance was verified.

f. The following Problem Reports were noted:

(1) Problem Report (PR) 90-0496: Unit 1 and Unit 2 procedure OHP 4021 007.002 valve line-up sheets 4 and 5 for the deborating demineralizers were performed in error in that the second line-up was signed off prior to Step 6.4.15.

Poor human factoring associated with the line-up sheets was mentioned as contributing to the error.

(2) Problem Report (PR) 90-0529: During a routine inspection, valve 1-FP-241 (Unit 1 diesel driven fire pump discharge throttle valve) was found unlocked and throttled open approximately five turns. A check of control room logs showed the fire pump was operated six days earlier for surveillance testing. It appears valve 1-FP-241 was inadvertently left in the test position following the pump surveillance.

One violation (not cited), and no deviations, unresolved or open items were identified.

4. <u>Maintenance (62700, 62703, 42700)</u>

Maintenance activities in the plant were routinely inspected, including both corrective maintenance (repairs) and preventive maintenance. Mechanical, electrical, and instrument and control group maintenance activities were included as available.

The focus of the inspection was to assure 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 inspected:

a. Job Order JO A019043: "Replace Unit 1 Essential Service Water (ESW) West pump bowl assembly, repair as required. Install new line and shaft bearings and pump packing." The decision to replace the pump came as a result of its failure to satisfy technical specification requirements during routine surveillance testing. At 7,000 gpm, the pump developed a 61 psig discharge pressure versus the required 61.3 psig. Accordingly, the pump was declared INOPERABLE on May 13, 1990, and the unit entered a 72-hour Limiting Condition for Operation (LCO).

   Through review of the monthly surveillances in accordance with ASME Section XI an adverse trend was noted in March, 1990. Subsequent discussions with the service water system engineer led to a determination to replace the pump during an upcoming refueling outage. However, an abrupt step decrease in pump performance led to its replacement earlier than anticipated.

   Activities observed included pump disassembly, inspection of shaft and bearings for wear, reassembly of pump, alignment of motor with pump, and the initial steps of reconnecting electrical leads. Both strengths and weaknesses were identified.

   Strengths - skills of the crafts were excellent. Prior planning and scheduling reflected good interface between the various groups working on the repair and a good knowledge of the activities involved. Working hour limitations were adhered to for all cases but one crew whose deviation had prior approval.

   Weaknesses - Procedure No. **12 MHP 5021.019.001, Rev. 7, effective date 07/02/87, "Maintenance Repair Procedure for Essential Service Water Pump," was used. Revision 7 was a minor revision and did not constitute a two year review. The last two year review which produced a major revision to the procedure was Revision 6, effective date 06/26/86. Instruction No. PMI-2010, "Plant Manager and Department Head Instructions, Procedures and Associated Indexes," requires procedures to ...be reviewed biennially (no less frequently than once every two years). In May, 1988 the 2W ESW pump was repaired per Job Order 017623, and subsequently failed its flow acceptance criteria. Several procedure enhancements and sequencing errors were identified by both the licensee and the NRC Senior Resident Inspector as documented in Inspection Reports 50-315/88016(DRP); 50-316/88018(DRP). The maintenance supervisor indicated that the procedure would be changed. One Change Sheet was issued on 06/02/88, however, this was to correct a tolerance adjustment and did not incorporate the changes identified in the inspection report mentioned above. On 05/14/90 the inspector requested to see any proposed changes to the procedure and the results of the last two year review which should have been conducted by 06/26/88.

The changes were never made. The licensee had no written record of doing a required two year review, although a computer entry indicated one was done on 07/02/88. They also had no record in their file of proposed changes to the procedure. One of the changes that the inspector found in his review of previous work on the 2W ESW pump (July 1988) involved the disassembly of a pump section that would have been impossible to perform in the sequence written. The failure to correct the deficiencies and sequencing errors that were identified in 1988 is considered a violation of 10 CFR 50, Appendix B, Criterion XVI (Violation 315/90010-02; 316/90010-01).

After the inspector identified some needed changes to the licensee, numerous other sequence changes were annotated on the procedure by the licensee and one additional procedure change sheet was written and approved. The licensee has indicated that they will change the procedure as needed after their review and an independent review by the vendor.

Pump replacement was completed on May 16, within the time required by the LCO and the pump was tested satisfactorily against the manufacturer's flow curve in accordance with **12 THP 6040 PER.001.

b. Unit 1 CD diesel generator underwent a 32-hour planned maintenance outage beginning May 21, 1990. Among the activities performed were various pressure switch calibrations done under generic calibration procedure 12 IHP 6030 IMP.033 and documented in several Job Orders.

Each Job Order was written in advance and a separate Job Order number was assigned to each individual pressure switch. Attached to each Job Order was a color photograph depicting individual switch location.

Activities observed included switch calibrations of jacket water pump discharge pressure, front bank air chest extreme hi pressure, and extreme low lube oil pressure. These were documented in Job Orders A51137/38, A51166, and A51153, respectively (the jacket water pump has two pressure switches). Lighting was poor in the area and a flashlight was needed and was available.

During the diesel generator's first subsequent operability run, the number two rear bank fuel injector (which had not been worked on) was observed to have a minor leak from its weep hole. Although this was not considered to threaten diesel operability, the licensee decided to replace the copper gasket. The first replacement proved too thin. A thicker gasket was installed after an inspection verified the seating surface was undamaged, and the diesel was declared OPERABLE after a second, successful run. Investigation showed these non-safety grade gaskets had been procured with a defined thickness specification, but the licensee had not independently verified thickness on receipt, there being no requirement to do so. When checked, more of these gaskets were found in stock which were not up to the thickness specification. This is being investigated.

c. Job Order JO A019025: "Unit 1 intermediate range excore nuclear instrument N36 repair; the instrument channel fuses blew repeatedly." A faulty detector power supply (step-up transformer) module was replaced. Procedure **1 THP 6030 IMP.130 "Intermediate Range Nuclear Instrument Calibration (N35, N36)" was used both as a troubleshooting guide and as the return-to-service test for this activity. A Quality Assurance inspector was also present monitoring this repair.

d. Job Order JO B018393: "Repair of steam leak through valve 2-MRV-232, the No. 3 main steam stop valve dump valve on Unit 2." Licensee procedure **12 MHP 5021.001.075, "Repair Procedure for Fisher Controls Angle Valves," was used for the mechanical repair, which consisted of installation of new internal parts and replacement of valve packing and seals. The Instrument and Electrical group set the valve stroke under the same Job Order. Both the stroke setting and post-maintenance testing were observed by the inspector.

e. Job Order JO A001764: "Perform spectrographic examination on valve parts for MRVs under Hold Tag HSP-9689." This activity was performed to verify the composition of parts purchased as commercial grade, as part of a "dedication plan" (No. DCC-PV-12-DP-071) to upgrade the parts to safety grade. The inspector reviewed this and other aspects of the upgrade because some of these parts were used in the safety related repair of valve 2-MRV-232 discussed immediately above.

There was one apparent discrepancy involving the number of parts issued out as non-safety grade versus the number analyzed and returned to be upgraded. In pursuing this, the inspector learned some parts were never tagged so as to be traceable to a specific Purchase Order. Therefore, there was no attempt to upgrade these parts. The inspector verified the parts actually available for safety grade use were properly traceable.

f. Job Order JO B038381: "Remove existing light fixtures and install new high pressure sodium light fixtures in auxiliary feedwater pump rooms." Scaffolding was set in place in both turbine driven auxiliary feedwater pump rooms to support the work. The scaffolding was rigidly held by cables tied to unobstructed areas of the floor and walls. At the time of the inspection, the turbine driven auxiliary feedwater pumps were considered OPERABLE, as were the motor driven auxiliary feedwater pumps. A few photographs of the scaffold were taken and sent to NRC Region III to assist in their ongoing generic evaluation of scaffold erected in safety related areas.

g. Project No. 5969-120: "Contractor (Nuclear Energy Services) to implement design change RFC-DC-12-3024 which replaces existing air-motor-driven fuel transfer system with a similar cable-driven transfer system." The work area and documentation were well ordered, with a controlled working copy of the contractor procedure present and in use at the work site.

h. The following Problem Reports were noted:

(1) Problem Report (PR) 90-0449: Chesterton packing on valve 1-IMO-362 (safety injection pump suction to and from charging pump suction Train B shutoff valve) was overtorqued by 15-percent.

(2) Problem Report (PR) 90-0537: Maintenance crew was observed moving the middle ice machine with the Auxiliary Building crane, in a manner inconsistent with the procedure to control heavy loads. A question was also raised as to the adequacy of the lifting beam.

One violation and no deviations, unresolved or open items were identified.

5. 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. **12 THP 6040 PER.118, "Main Steam Stop Valve Dump Valve Pressure Tests." This newly-developed procedure was utilized May 1 and 3, 1990, for Units 1 and 2 stop valve dump valve testing, respectively. The procedure established baseline dump valve leakby values via the pressure drop method, relatable to ongoing acoustic emission measurement on the valves for detecting any significant change in leakby. The procedure was found to be technically accurate and effective, though minor administrative improvements were noted for correction. When dump valve 2-MRV-232 was later repaired (ref. Paragraph 4.d) the licensee recognized the baseline could have been altered, so the test was promptly repeated for the affected valve.

b. **1 OHP 4030 STP.018, "Steam Generator Stop Valve Dump Valve Surveillance Test." This routine valve stroke-timing test was used for component operability verification following return to service from the pressure-drop testing discussed immediately above.

c. **2 OHP 4030 STP.007W, "West Containment Spray (CTS) System Operability Test." Documentation was reviewed for two tests completed on April 22 and May 8, 1990. Although the results satisfied the Inservice Inspection (ISI) criterion for the pump and associated valves, some errors were noted.

A "note" following Step 8.2.5 instructed the user to compare pump performance to the Technical Data Book to determine operability of the East CTS pump. The comparison should be for the West pump. Additionally, the calibration due date marked on the pump's discharge pressure gage was December 14, 1989. The inspector checked this date against the IDS (Instrument Data Schedule) which is the "official" program for instrument calibrations. The IDS revealed an actual due date of August 1, 1991. Finally, two different calibration due dates were listed on the same vibration probe. The May test sheets showed the correct due date of May 18. The April 22 test sheets had a May 8 due date.

d. **12 THP 6030 IMP.214, "Protective Relay Calibration." The instantaneous trip relay for the motor-driven North hotwell pump in Unit 2 was being calibrated. A precaution that the current transformer be shorted was not signed-off on the instantaneous overcurrent relay data sheet. The workmen showed that the transformer was short-circuited as required. The Step was then signed to reflect compliance with the requirement. Licensee management expectations for signing off concurrently with performance of the specified action were discussed at the Management Interview.

e. On May 17, 1990, the inspector noted during review of a controlled copy of Procedure 2 OHP 4030.001.002, "Containment Inspection Tour," filed in the satellite library on the fourth floor of the new office building, that procedure page 2 of 4 was incorrect. Data Sheet 1, page 2 of 4, was recently revised via Change Sheet 2; this was misfiled as the procedure page. Document control personnel were notified and the procedure corrected that same day.

f. The following Condition or Problem Reports were noted:

(1) Problem Report (PR): "Unit 2 East Essential Service Water (ESW) pump was less than the minimum allowable (Technical Specification) discharge pressure limit." The limit was 59.9 psig and the actual value was 59.3 psig. Evaluation later determined the Unit 1 limit was referenced and the 2 East pump met Unit 2 requirements.

(2) Problem Report (PR): "Unit 1 diesel generator start relays were out of allowable tolerance." Seven relays were discovered during calibration checks to be beyond the Technical Specification allowable values. Licensee Event Report 316/88003-LL documents (through seven revisions) the history of relay problems. The relay manufacturer does not specify the relay's ability to accurately repeat its setpoint value; the licensee believes the Technical Specification values are overly restrictive in that the setpoint tolerances are closer than the

relays can obtain and closer than required to perform the intended function (i.e. voltage sensing, load shedding, diesel starting). A Technical Specification Amendment has been submitted to NRR; meanwhile, the licensee has changed the calibration frequency from every 18 months to monthly.

(3) Condition Report (CR): "Unit 1 ice condenser intermediate deck door No. 19 inoperable due to ice buildup." A leaking drain line from Air Handling Units (AHU) 32A and B was identified as the cause as water entered the ice condenser flow passage lattice work. Inspections by Operations Department personnel revealed no flow blockage. The drain line was subsequently repaired and ice was removed.

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

6. 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. "Dedication" of Commercial Grade Parts (35502)

During the review of the Dedication Plan to upgrade commercially procured parts for the main steam stop valve dump valves (ref. Paragraph 4.e above) the inspector identified a discrepancy between the "Critical Characteristics and Acceptance Criteria" specified in the plan and those actually applied. The plan specified a verification of proper dimensions, in part, by performance of a post maintenance test using Procedure **2 OHP 4030 STP.019F, "Steam Generator Stop Valve Operability Test." When some of these parts were installed to repair valve 2-MRV-232 on May 11, 1990, the test actually performed used Procedure **2 OHP 4030 STP.018, "Steam Generator Stop Valve Dump Valve Operability Test." This was the correct test; the Dedication Plan specified a test which cannot be performed with the unit in service. The licensee was notified of the discrepancy and initiated corrective action to reconcile the discrepancy.

b. PWR Moderator Dilution (25594, 71707)

The inspector performed an inspection of licensee actions, administrative controls and/or plant modifications in response to DOR (NRC) Information Memorandum No. 7, "PWR Moderator Dilution" dated October 4, 1977. Temporary Instruction 2515/94 dated March 31, 1988, was used in this review.

The licensee's file on this topic contained the following correspondence, which was reviewed.

Letter, NRC to licensee: September 15, 1977
Responses, licensee to NRC: December 22, 1977; July 20, 1979; August 28, 1979
Letter, NRC to licensee: March 19, 1980

The NRC letter of March 19, 1980 concluded with the words, "...you have reviewed potential boron dilution...and have determined that the FSAR analysis of this event still represents the most limiting case. Based on your response no further action regarding this generic issue is necessary." The licensee made neither administrative control changes nor plant modifications, as both were judged unnecessary. This judgement rested both on existing design and on administrative control of sodium hydroxide (dilutant) valves during testing.

The inspector verified the design remains materially unchanged. One additional potential dilution source had been created in 1988 by installation of a cross-tie line between the chemical and volume control systems of the two units. This dilution potential was recognized and appropriate controls had been provided.

The inspector also performed a review to determine whether the administrative controls for valve testing, upon which the licensee relied to prevent NaOH dilution, remained in effect. The licensee's letter dated July 20, 1979 describes these controls to result "...in three closed hand-valves in series ...preventing flow ...to the reactor coolant system." The valves are designated on an attached drawing as valves V-1, V-4 and V-5. With three series isolation valves, the licensee concluded neither the misposition of a single isolation valve, nor a single active component failure, could result in undesired leakage.

The inspector found the licensee's current test procedures (1- and 2-OHP 4030 STP.007E) no longer stipulate closure of the valve designated "V-4." (Actually, this is a pair of parallel valves, one to each containment spray pump suction, designated CTS-119E and CTS-119W respectively.) Still, the other two series isolation valves (designated V-1 and V-5) are closed and the protection from single valve mispositioning or single component failure remains.

Based on the reviews and findings described above, this issue is considered closed.

c. Problem Reports

The following Problem Reports were noted:

(1) Problem Report (PR) 90-0494: "Unit 1 SPDS (Safety Parameter Display System) high average temperature alarm setpoint was not changed to reflect the amended Technical Specification." The finding was discovered during an Offsite Review Committee audit of the SPDS for Units 1 and 2.

(2) Problem Report (PR) 90-0433: "Procedure **12 THP 4030 STP.308 (Boron Curve Update) completed on March 30, 1990 was found to have a calculational error." The error was discovered after a procedure revision while preparing for the next scheduled surveillance. When the surveillance was recalculated, it was verified that no Technical Specification limit was exceeded.

(3) Problem Report (PR) 90-0312, "Nonessential Service Water (NESW) containment isolation valves 2-WCR-964 and 2-WCR-966 for the West containment room ventilation unit failed to fully close on an NESW isolation signal." The valves appeared to be stymied by a "hydraulic lock" with their respective isolation boundary redundant valves.

A series of tests was performed under various potential system configurations in an attempt to understand the "hydraulic lock" phenomenon. In all cases, at least one valve closed, providing containment isolation (i.e. when an "inner" valve failed to close, the "outer" valve always closed). No reportability was deemed necessary following consultation with Operations Department management and the licensee's corporate Nuclear Safety and Licensing staff. The licensee's shift technical advisors review recommended a further engineering study to include generic implications in systems with similar piping configurations. This appeared appropriate.

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

7. Emergency Preparedness (82201, 82203)

The licensee declared a Unit 1 "Unusual Event" on May 24, 1990, after the explosive failure of a 345 KV switchyard breaker at about 3:00 a.m. (EDT) led to a fire of greater than 10 minutes duration. This classification and the subsequent notifications appeared proper.

An Emergency Plan "Alert" was declared for Unit 1 at 6:15 a.m. that same day upon discovery of damage from the initial explosion which impacted another breaker and thereby affected unit operation; unit power needed to be reduced to permit switching and manipulations to isolate the second damaged breaker. This classification was conservative and subsequent notification appeared proper.

Additional event details, and licensee and NRC actions and inspections in response to this event, are discussed in Paragraph 9 below.

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

8. Licensee Self-Assessment (40500)

a. Onsite Review committee.

The inspector performed a selective review of meeting minutes for the Plant Nuclear Safety Review Committee (PNSRC) during the period July, 1989 through May, 1990. No instances were noted involving any

failures to meet requirements of the technical specifications covering PNSRC organization, membership, meeting frequency and review responsibilities. On a few occasions, the NRC inspector attended a PNSRC meeting to observe.

The use and designation of PNSRC subcommittees were reviewed, as was the system for designating members and alternate members of the committee.

Implementation of the corrective action program, including PNSRC involvement in the more significant matters, was routinely monitored by the inspector. Licensee Problem Assessment Group (PAG) meetings were attended daily when the inspector was onsite, to observe event classification, assignment of responsibilities and schedule for investigation, and focus on safety or generic implications. These activities were conducted in compliance with the licensee's Plant Manager's Instruction (procedure) PMI-7030, "Condition Reports and Plant Reporting."

All Licensee Event Reports (LERs) issued during the review period were screened by the inspector shortly after issuance. This served in part as a check on PNSRC oversight of these matters. The screening emphasized compliance with reporting requirements and adequacy of information to permit an independent determination on cause, significance and regulatory implications of the reported matter. No significant problems were noted.

b. Independent Safety Assessment.

Various activities of the plant Safety and Assessment Department (S&A) were monitored or reviewed. The S&A Department had responsibilities in the areas of: corrective action; events and operating experience assessment; event response; fire protection; trending; and quality control/nondestructive examination (NDE).

The inspector reviewed S&A weekly reports to plant management concerning department activities and issues. Quarterly trend reports, covering statistics on various categories derived from the corrective action program, were also reviewed. Discussions were occasionally held with individual S&A personnel concerning their activities and the day-to-day functioning of their organization.

Utilization of the Human Performance Evaluation System (HPES), for investigating and determining causes of events, was selectively reviewed. This process was not heavily utilized over the past year. During this period, the HPES Coordinator (a position entailing specialized training) took a maternity leave, returned for a time, then resigned and had to be replaced. Thus, the program suffered some lack of continuity. A review of some of the evaluations which were done found them apparently proper and thorough. Some events were not completely processed on a timely basis. A few remained "open" a full year after the original event. This was noted at the Management Interview.

c. Management Oversight Functions.

The inspector met weekly with the Plant Manager or his designee to discuss plant-specific and industry matters. A new Plant Manager was named in September, 1989, replacing an incumbent with about seven years experience in the position. The new Manager, however, had formerly served in two different Assistant Plant Manager positions, as well as other supervisory/managerial positions in the technical organizations onsite. He was uniformly well-informed on plant-specific issues.

The inspector verified by routine review of several departmental "weekly" reports that significant amounts of internal performance-related data (in numerous categories) is supplied to management on a regular basis. On several occasions, the inspector questioned senior managers about trends or anomalies which appeared in the data; they were conversant with and knowledgeable about these issues in each case.

External sources of information on, and assessments about licensee safety performance were selectively reviewed. This review included the 1989 evaluation report by the Institute for Nuclear Power Operations (INPO) which the licensee loaned to the inspector to read. The INPO evaluation report did not identify significant safety problems of a nature warranting NRC involvement to meet its regulatory obligations.

The licensee did not make frequent or routine periodic use of third-party assessments, although a few such assessments were contracted to provide perspective on specific issues. An example is noted in Paragraph 2.b above.

d. Summary.

On the basis of the above reviews, the inspector concluded:

(1) the licensee adequately reviews and assesses plant and industry operating experience and appropriately applies the information derived thereby;

(2) plant performance is evaluated both in detail and in depth;

(3) conservative judgements are usually made for any matters potentially affecting safety or involving unreviewed safety questions;

(4) corrective action program dictates are met to a substantial degree, with exceptions requiring individual approval; and,

(5) management is generally well informed about the views of each of the several outside sources of performance assessment.

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

9. Potentially Significant Event (82201, 82203, 93702)

a. Event Description - General.

As noted in Paragraph 7, above, D. C. Cook Unit 1 was in an Emergency Plan "Unusual Event" and "Alert" status for several hours on May 24, 1990, due to a fire and explosion damage, respectively, in the 345KV switchyard. The initiating event, at about 3:00 a.m. EDT, was destructive failure of the current transformer (fault monitoring device) associated with one phase of the "L" cross-tie breaker between buses 1 and 2. An oil fire ensued, which was reported at 3:05 a.m. by site security (the switchyard area is a half-mile East and not visible from the plant). This involved the approximate 300 gallons of current transformer oil.

The "Unusual Event" was declared at 3:15 a.m., as specified for fires of ten minutes duration in the Emergency Plan. Notifications were made by the Unit 2 personnel at the request of Unit 1. It was not clear from the initial notifications which unit was most involved, partly because the only breaker monitored in either control room which was affected by the event, was Unit 2 765KV switchyard breaker A2. This breaker opened to "clear" 765KV bus No. 2 in response to the "breaker failure" logic from the "L" breaker.

The site fire brigade and local fire departments responded to the fire scene, but active firefighting was not attempted on the advice of company power distribution specialists who had arrived at the yard to assist. The fire was extinguished after proximate equipment was de-energized, and it had greatly burned down, at 6:55 a.m.

At 6:15 a.m. the licensee declared an "Alert" upon discovery of explosion damage to a current transformer associated with 345KV breaker "K1", which is a Unit 1 output breaker. Explosion fragments had struck two ceramic cooling vanes on the K1 current transformer, cracked the ceramic, and caused an oil leak. This condition placed Unit 1 in jeopardy because the other output breaker, K2, had opened when bus No. 2 "cleared" in the initial event. Restoration of K2 at 70-percent power (where the Unit was base-loaded) was judged to be a threat to system stability, so the Unit was backed down to about 60-percent. Any explosion having an effect on unit operation is an "Alert" classification.

Region III dispatched the SRI, an electrical specialist and an emergency planning specialist to the site. An open communications line was maintained throughout the "Alert" to both Headquarters and the Region III Incident Response Centers, which were actuated and staffed to a heightened awareness condition. The "Alert" was terminated at 11:38 a.m. EDT after the Unit 1 No. 2 bus was restored and breaker K1 de-energized. Periodic reports were received thereafter concerning additional restorations in the 765KV yard and at the No. 4 transformer cross-tieing the two yards. Preliminary Notifications PNO-III-90-33 and -33A were issued, and Region III responded to a few press inquiries.

b. System/Equipment Response.

The performance of protective relaying and consequent component actuations were reviewed to verify whether they were per design.

Prior to this event, all the 345KV switchyard breakers were closed.

The 345KV Delle Alsthom PK-4B air operated circuit breakers located in the switchyard are arranged in a breaker-and-a-half configuration. The breakers are designed to open in two cycles (approximately 33 msec.). One breaker and a multiple winding bushing current transformer (CT) is used per phase. The CTs provide input to the protective relaying schemes. The electrical/mechanical failure of the CT of Breaker No. L for phase two ignited the CT oil as the CT insulator broke apart. The resulting line transient initiated the opening of Breaker Nos. L and L1 on a protective relaying sensed line fault.

A 345KV Bus No. 2 lockout occurred approximately one cycle following the opening of the L and L1 breakers. Preliminary investigation indicates the electrical failure of the CT had occurred between the CT closest to the L breaker and the L breaker head. The protective relaying indicated an instantaneous phase line fault had occurred. Power was still available from Bus No. 2 to the CT side of the L breaker. Bank four differential relays sensed the unbalanced differential current and initiated the breaker failure logic which opened Breaker Nos. K2, M2, N2, BC (normally open), and A2, B2 in the 765KV switchyard which isolated Bus No. 2.

The D. C. Cook 345KV switchyard incorporates a timer controlled, high speed fast closure line breaker logic. The L configuration breakers provide the one-half breaker isolation between the line breakers and will not automatically reclose. This scheme is used to restore line power immediately following a momentary line fault, such as from ice buildup. If the fault is present longer than the timer, the line breaker (such as L1) will remain open. In this case, the L breaker was open and isolated the fault from the Robinson Park Line. The L1 breaker then successfully reclosed and reconnected the Robison Park Line to Bus No. 1.

Indiana Michigan Power personnel arrived on-site shortly after the fire had erupted. They were aware that the L1 breaker was closed and were in the process of obtaining permission to isolate the L breaker by opening L1. The CT oil was still in flames when an arc-over occurred and L1 opened automatically. The Robinson Park line was isolated and the Robinson Park static relay indicated the isolation occurred from either an instantaneous ground fault or a phase instantaneous trip. Switchyard personnel surmise the arc-over may have occurred from decreasing breaker air pressure (normally 3700 psi) which serves as both an insulating medium and provides the motive force to open/close the breaker.

The inspector reviewed the Bus No. 2 lockout logics for 345KV Breakers Nos. L and L1. The drawings reviewed included the following:

. E-30292-2805-10	CB-L1 (Robinson Park)
. E-30292-2807-7	CB-L, L1, BF
. E-30292-1000A-17	Unit No. 1 and 345KV One-Line
. E-3092-1000B-7	Unit NO. 2 One-Line

The inspectors concluded that the above breaker actions had occurred as per design.

The switchyard oscillograph recording was sent to American Electric Power (AEP) for analysis. AEP had not completed their review as of the end date of this inspection. The inspector has requested a copy of the analysis and unless there is a major change in the above sequence of events, the inspector has no further questions on this item at this time.

c. Licensee Emergency Response

D. C. Cook; Alert; May 24, 1990

Upon arrival at the Technical Support Center (TSC), at approximately 1050 hours, the inspector observed the facility to be activated and staffed. Status boards were filled out and up to date. The plant's status and situation in the switchyard were well understood and controlled.

An adequate briefing was provided to the inspector by the Senior Resident Inspector and licensee personnel to clearly convey the current plant status and ongoing activities. Communication between the TSC and other facilities was maintained and functioned very well.

At 1138 hours, the Alert was terminated after an appropriate discussion with the State and key licensee personnel. Prior discussions and evaluations had been conducted to determine the actions necessary to reach a condition which would be considered stable and allow terminating from the event.

Available records, log books, status boards and data sheets were gathered and retained for later evaluation.

At 1400 hours on May 24, 1990, the licensee convened a meeting to begin a post emergency investigation in accordance with Emergency Plan Administrative Manual Section 6.0. This meeting was attended by the individuals who had been selected to be the Investigation Committee. This committee consisted of a cross section of personnel with appropriate plant expertise who had not been directly involved in the actual event.

The overall goal of the Investigation Committee was discussed and time frames for completion of selected activities were established.

The committee proceeded to develop a list of all pertinent data, records, logs, trend sheets, computer histories, and other information that would be appropriate and applicable to analyse the event. A list of key personnel involved in the event was also developed.

Assignments were then made for interviews of individuals involved and gathering of the identified records for evaluation. A time was set to hold a post event critique with the key involved individuals.

At 1000 hours on May 25, 1990, the licensee convened a post event critique which was attended by the inspector, many of the key individuals involved in the event, as well as the Investigation Committee. The critique consisted of an orderly review of each emergency response facilities activities and a reconstruction of the time line of events from memory of the involved personnel.

Based upon information obtained in the event critique and a review of pertinent licensee records, it has been determined that the licensee appropriately classified the event as an Unusual Event in accordance with ECC-5 and later upgraded to an Alert in accordance with ECC-4. Both classifications were recognized and declared promptly. Notifications of State, local, and federal authorities were made almost immediately and well within time requirements.

Emergency response facilities - The Technical Support Center (TSC), Operation Staging Area (OSA), and the Emergency Operations Facilities (EOF) were activated and staffed in a timely manner.

Overall, the licensee responded in a prudent and timely manner to the event. Applicable emergency procedures were utilized and the established emergency plan was activated and proved to be adequate to address the event.

Through self critique following the event the licensee identified several strengths and a few minor areas which need improvement.

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

10. Management Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on June 6, 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.

The following items were specifically discussed:

a. the items to be "Closed" on the basis of this inspection were identified (Paragraphs 2 and 6.b);
b. unit operations during the inspection period, especially items affecting power level (Paragraph 3);

c. regulatory violations identified in the Operations (Paragraph 3.c) and Maintenance (Paragraph 4.a) areas;

d. administrative control weaknesses (typographical errors, delayed signoff, misfiling) noted in observation and review of Surveillance (Paragraph 5);

e. selected licensee-identified Problem Reports in various areas (Paragraphs 3.f, 4.h, 5.f, and 6.c) as well as an overview on licensee self-assessment (Paragraph 8); and,

f. licensee and NRC actions in response to a potentially significant event (Paragraphs 7 and 9).