U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Reports No. 50-315/89009(DRP); 50-316/89009(DRP)

Docket Nos. 50-315; 50-316 Licenses No. 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, Michigan

Inspection Conducted: February 8 through March 21, 1989

Inspectors: B. L. Jorgensen

D. G. Passehl

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Approved By: B. L. Burgess, Chief
Projects Section 2A

4/4/89
Date

Inspection Summary

Inspection on February 8 through March 21, 1989 (Reports No. 50-315/89009 (DRP); (DRP); 50-316/89009(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of: actions on previously identified items; plant operations; reactor trip signals; radiological controls; maintenance; surveillance; fire protection and cleanliness; reportable events; NRC Circular; miscellaneous Emergency Notification System (ENS) events; and NRC Region III requests. A special NRC consultant inspection included: preparations for startup; modifications and complex surveillance testing; and, followup inspection on other matters relating to Unit startup after an extended outage. No SIMs items were specifically reviewed.

Results: Of the 15 areas inspected, no violations or deviations were identified in 13 areas. Two violations were identified (Level IV - work performed to

unreviewed/unapproved guidelines - Paragraph 6; Level V - not cited - combustible material control procedure not followed - Paragraph 8); one in each of the remaining two areas.

The inspection disclosed occasional weaknesses in the licensee's strict adherence to procedure details while striving to get a job done. The inspection noted strengths in the licensee's implementation of significantly expanded preventive maintenance (PM) activities and aggressive completion of corrective maintenance items identified by the PM program.

A new Open Item was identified (and is discussed in Paragraph 11) involving a test procedure containing a narrower pump recirculation flow criterion than can be verified using the existing flow gauge.

DETAILS

1. Persons Contacted

*W. Smith, Jr., Plant Manager
A. Blind, Assistant Plant Manager - Administration
J. Rutkowski, Assistant Plant Manager - Production
*L. Gibson, Assistant Plant Manager - Technical Support
B. Svensson, Licensing Activity Coordinator
K. Baker, Operations Superintendent
*J. Sampson, Safety and Assessment Superintendent
E. Morse, QC/NDE General Supervisor
T. Beilman, I&C/Planning Superintendent
J. Droste, Maintenance Superintendent
T. Postlewait, Technical Superintendent - Engineering
*L. Matthias, Administrative Superintendent
J. Wojcik, Technical Superintendent - Physical Sciences
M. Horvath, Quality Assurance Supervisor
D. Loope, Radiation Protection Supervisor

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

*Denotes some of the personnel attending Management Interview on March 22, 1989.

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

a. The following previously identified items are considered "closed" based on NRC Region III management review. Pursuant to instructions to the inspector (memo from W. D. Shafer, Acting Deputy Director, DRS, dated February 8, 1989) they are documented here for traceability:

(1) Violations -	315/85007-04	and	316/85007-04
	315/86019-02	and	316/86019-02
	315/87022-03	and	316/87022-03
	315/87022-1A	and	316/87022-1A
	315/87022-2C	and	316/87022-2C
(2) Unresolved Items -	315/84013-11	and	316/84015-11
	315/86022-04	and	316/86022-04
(3) Open Items -	315/82008-05	and	316/82008-05
	315/82008-07	and	316/82008-07
	315/82008-08	and	316/82008-08
	315/83002-02	and	316/83002-02
	315/85013-01		

315/85013-08	and	316/85013-08
315/85013-12	and	316/85013-12
315/85036-01		
315/86005-07	and	316/86005-04
315/86015-05	and	316/86015-05
315/86015-09	and	316/86015-09
315/86015-10	and	316/86015-10
315/86015-14	and	316/86015-14
315/86015-15	and	316/86015-15
315/87007-02	and	316/87007-02
315/87016-03	and	316/87016-03

b. (Closed) Violation (315/88023-01). Failure to control Unit 1 hydrogen skimming system dampers as specified by procedure. The licensee's response to the violation (letter - AEP:NRC:1060L dated December 5, 1988) described adequate corrective and preventive measures for this violation. These measures were selectively verified by the inspector.

c. (Closed) Unresolved Item (315/88020-02). The hydrogen skimmer test procedure contained acceptance criteria different from (less conservative than) the FSAR limits. As part of Licensee Event Report 315/88008-LL (see Paragraph 13.b) which addressed the hydrogen skimmer damper mispositioning noted in b. above, the licensee performed a "sensitivity analysis" of skimmer system flow rates. This analysis, which was even less conservative than the test procedure values, nevertheless showed the system still met Regulatory Guide 1.7 limits for post-accident hydrogen concentration.

d. (Closed) Violation (316/88014-08). Repetitive failure to proceduralize license amendments, resulting in failure to perform required channel checks. The licensee's response to the violation (letter - AEP:NRC:1060C dated June 8, 1988) described adequate corrective and preventive measures for this violation. The inspector selectively verified both the implementation and the effectiveness of these measures. They appear to have been effective in preventing a recurrence of this problem.

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

3. Operational Safety Verification (71707, 71710, 71711, 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.

Evaluation, corrective action, and response for off normal conditions or events, if any, were examined. This included compliance to 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. Unit 1 was operated routinely at 74-percent power until February 28, 1989, when power was reduced to 54-percent. The reduced power operation was implemented to extend the Unit operating cycle past Unit 2 startup, such that both Units would not be concurrently out of service. A scheduled shutdown to begin an approximate 90-day refueling, maintenance, modification and testing outage was performed on March 18, 1989. During the shutdown, the Unit tripped from about 10-percent power; see Paragraph 4.c.

b. Unit 2 achieved initial criticality on March 15, 1989, concluding a scheduled 327-day outage which encompassed numerous significant activities, including the Steam Generator Repair Project (SGRP). The inspector observed the criticality and portions of the succeeding startup activities, including paralleling the main generator on March 17, 1989.

   Return-to-service preparations were a dominant part of Unit 2 activities during this inspection, and were routinely reviewed by the NRC inspector as discussed throughout this report. In addition, an NRC Consultant inspector performed a focused review of selected aspects of the Unit 2 return-to-service process. The results of these special reviews are documented in Paragraphs 9 through 12 of this report.

c. During a system walkdown in the Unit 1 nonessential service water (NESW) valve gallery, the inspector noticed two control solenoid valves leaking air. These valves supply air to operate containment isolation valves (CIVs) in the NESW lines to the containment ventilation units. The inspector informed the licensee and checked the most recent record of in-service tests (IST) for the two CIVs (ref. procedure No. 1-OHP 4030 STP.011). The inspector noted a potential problem with regard to documentation of test results. This is discussed further in Paragraph 7.e, "Surveillance".

d. One auxiliary building tour was specifically oriented toward housekeeping, as increasing examples were being noted of a decline in housekeeping standards. A list of items was derived from this tour and provided to plant management for evaluation and appropriate action. No significant problems were noted, but the observed conditions were not up to the standards previously established and desired.

e. The inspector also made a housekeeping tour of the Unit 2 lower containment, with one of the Assistant Plant Managers, to observe conditions as the Unit was nearing completion of the eleven month steam generator repair outage. Despite the massive amount of debris generated because of the project, conditions were generally good, with some exceptions:

(1) condensation from the reactor coolant pump air coolers was overflowing the drip trays on to the basement floor where it collected in small puddles at various places. Although this water is nonradioactive, it has the potential to wash over and spread areas of contamination;

(2) the inspector found a couple of screwdrivers, a hacksaw blade, pens, and other debris which had apparently fallen into a control rod drive (CRD) ventilation duct. The Assistant Plant Manager was made aware of this condition and the plant responded by cleaning and inspecting this and the other CRD ducts.

f. The inspector interviewed Operations Department management concerning operating practices or controls on manual valves operated by "reach-rods". Two such valves were identified on recent Condition Reports as having been found inoperative. The findings were only three days apart.

The inspector was advised that "reach-rod" valve operators are not subject to any fixed periodic exercising or other specific operability check. The Maintenance Department was said to have developed a periodic preventive maintenance program in recent years (see Paragraph 6.a) due in part to increasing valve operator problems. Operator visual verification of correct position after manipulation - the valves are typically equipped with position indicator "pointers" - was characterized as an expected "good practice", but this expectation was neither formalized nor otherwise emphasized.

Operators are also expected to initiate repair Job Orders for reach-rod operated valves which are balky or evidence damage. This was supported by the fact an "open" Job Order existed for one of the two "inoperative" valves identified/noted above.

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

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

a. On February 24, 1989 with Unit 2 in MODE 5 during a turbine test procedure which required the reactor trip breakers to be closed, a spurious reactor trip signal was generated by the solid state protection system (SSPS). The No. 24 steam generator had a standing

steam/feed flow mismatch signal (which the licensee was in the process of troubleshooting) when a spurious No. 24 steam generator low level (§26 percent) signal occurred. Actual level at the time of the trip was 33 percent. This event may be reviewed further on receipt of the anticipated Licensee Event Report (LER).

b. Unit 2 experienced another reactor trip signal on March 10, 1989. The Unit was in the process of cooling down from MODE 3 to MODE 5, with all control rods fully inserted and the reactor trip breakers open, when narrow range water level in the No. 21 steam generator fell to the lo-lo setpoint and initiated the trip signal. The licensee considered root cause to be operator error in not monitoring water level closely or frequently enough. Auxiliary feedwater was already in service for the cooldown, so flow was simply increased to restore water level above the trip setpoint. The signal had no effect on plant systems or components. An LER is also anticipated on this item.

c. Unit 1 tripped from about 10-percent power during a scheduled shutdown to begin a refueling outage on March 18, 1989. The cause of the trip was actuation of the Intermediate Range Nuclear Instrument N-35 high power trip. This is a standing trip signal above about 25-percent power, which is manually blocked during a controlled startup. During a controlled shutdown, the trip should "reset" between 25-percent and 10-percent power. This "reset" function is a separately controlled setpoint from the trip setpoint. At 10-percent power decreasing, the "block" is automatically removed, so, if the channel has not reset, the standing trip signal actuates a reactor trip. This is just what occurred in Unit 1 to cause the subject event. Subsequent investigation indicated the reset setpoint had been set too low (for both N-35 and N-36; coincidentally, the latter had just cleared and the former almost did) since Unit startup at the beginning of the fuel cycle in October, 1987.

Plant response to the trip was nominal. The root cause was not immediately evident, however, and early opinions and information on the matter had to be revised. This event will be reviewed further in follow up to the anticipated Licensee Event Report on the topic.

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

5. Radiological Control (71707)

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

Effluent releases were routinely checked, including examination of on-line recorder traces and proper operation of automatic monitoring equipment.

Independent surveys were performed in various radiologically controlled areas.

During one auxiliary building tour, the inspector's portable radiation instrument responded poorly at the check station on the 650-foot level. By scanning with the instrument, it appeared that the sealed radiation source, mounted inside the locked box which serves as the check station, had become detached and fallen to the bottom of the box. Radiation protection personnel were notified and corrected the problem.

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

6. Maintenance (62703, 42700)

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 723517: Perform Attachment No. 56 to MHI-5030; e.g. preventive maintenance on about 160 "reach-rod" operated manual valves. The inspector reviewed the documentation package for this activity in followup to the observation that two such valves were recently found inoperative within a 3-day period. See also Paragraph 3.f above.

The preventive maintenance (PM) consisted of a physical inspection of specified attachments (bolts, pins, set screws) joints and gears for tightness, wear/damage, or binding as appropriate. All zerk fittings were to be greased. This PM was done for the first and only time in March and April, 1988. The currently specified frequency is annual.

The following observations were derived from the inspector's review:

(1) Valve 1-SI-106S (South safety injection pump recirculation), which was found inoperative on February 16, 1989, (Condition Report No. 1-02-89-317) was not included among the valves inspected/maintained under the PM. A repair Job Order

(No. JO 731279 dated January 6, 1988) had previously been written "due to excessive force required to operate the valve", but the work had yet to be done; it was categorized as "Unit 1 outage required". There has been no Unit 1 outage (involving cold shutdown) since October, 1987.

(2) Valve 2-CTS-121E (East containment spray heat exchanger inlet), which was found inoperative on February 19, 1989 (Condition Report 2-02-89-336) was only partially inspected and greased "due to location". Further, the first U-joint zerk needed replacing - a condition for which Job Order No. JO 024501 was written April 19, 1988. This repair had been completed and the Job Order "closed" on July 11, 1988.

(3) There were several symptoms of the fact this PM had been done only once and needs refinement:

- The individual Task Sheets (one per valve) did not match the computerized Facility Data Base (FDB) list of "reach-rod" valves; no Task sheets were found for five FDB-listed valves, and one sheet covered a valve not on the FDB list.

- A total of 30 "corrective" Job Orders were written to address (mostly minor) deficiencies, implying about one valve in five needed attention to restore conditions to optimum. At the time of the inspection, all but one of these 30 Job Orders had been done, indicating vigorous followup on the findings. Repair parts were fabricated and the last item was "ready to work".

- Both the FDB list and the Task Sheets omitted (besides valve 1-SI-106S noted above) at least five other "reach-rod" valves - these were identified by a simple screening of the Unit 1 FDB list against the Unit 2 list to see whether like valves were listed for both Units. They were verified by reference to controlled drawings and inspection in the plant.

- Maintenance crews typically misunderstood a "Job Order" blank at the bottom of the Task Sheet, recording the PM JO number when the blank was intended for recording the number of any necessary repair JOs initiated to correct deficiencies. In one case (Valve No. 2-CS-357) the Task Sheet described a broken handwheel faceplate, but the JO number recorded was for preventive maintenance. It appears this deficiency was not reported for repair.

The inspector concluded that preventive maintenance of reach-rod type manual valve operators is much improved from two years ago (when no formal program existed) and is yielding

beneficial results, but more refinement is still in order. Specific details on the observations summarized above were provided to the licensee for his information and appropriate followup action.

b. Job Order No. JO 760129: Clean and inspect 4KV circuit breaker No. T11A7 (West component cooling water pump power supply) per procedure **12 MHP 5021.082.001 "Inspection and Repair of 4KV Power Circuit Breakers".

This activity was inspected as an example of enhanced breaker preventive maintenance following failure of a similar 4KV breaker during testing. The failure was ascribed to deterioration of the lubricant on the triggering linkage. This lubricant had previously been considered "lifetime" lubricant. The procedure referenced above specifies, at Step 7.10.4, that lubrication is to be performed "as necessary". The subject breakers were manufactured in about 1971, and had for years been cleaned, inspected and lubricated (excluding the triggering linkage) on a refueling frequency. The procedure provided no instructions concerning how to clean and lubricate the triggering linkage, nor was lubricant type specified. A separate, typed page entitled "Guideline for Cleaning/Relubing Triggering Linkage" was present at the job site. This "Guideline" contained specific information of the type lacking from the procedure and it was being followed by the work crew. There was no cross reference to the "Guideline" from the procedure or the Job Order, however, and the "Guideline" was not formatted for signoff documentation that would address who did the work and when. Discussions with maintenance management indicated the "Guideline" had purposely been held separate from the procedure for the initial cycle, pending written verification from the breaker vendor (who had specified the lubricant) as to how frequently the triggering linkage lubrication should be or could be performed. Subsequently, the decision was made to incorporate triggering mechanism lubrication into each refueling-frequency inspection and repair. Another use of a "guideline" is discussed in Paragraph 6.d below.

Subsequent to the breaker failure which precipitated the activity discussed above, a second breaker also failed - again during a test operation outside its service cubicle. The licensee, who had issued an industry notification via INPO after the first failure and received only a single inquiry, began an active process of contacting numerous other plants for information on similar problems elsewhere. When three plants were identified with similar previous events, the licensee initiated a 10 CFR Part 21 evaluation. A Part 21 Report was determined necessary and was issued March 3, 1989.

c. Job Order No. JO 013923: Repair oil leak causing soaked lagging on No. 4 main steam stop valve. This activity was twice expanded in scope. The original repair efforts involved replacing seal O-rings in hydraulic lines for the valve assist/test actuator, along with

replacement of oil-soaked lagging. The hydraulic assist system subsequently showed oil leakage at the relief and recirculation valve, so the valve was also replaced. This first scope change appeared insignificant. The new valve, however, was not properly set to recirculate hydraulic fluid (at 1500 psi) when the steam stop valve reached the full closed (up) position; rather, it was apparently completely closed, preventing fluid recirculation. When the steam stop valve was stroked closed with the hydraulic system, the system continued pulling the valve stem with increasing force after the valve was seated closed. Hydraulic forces ultimately fractured the coupling nut threaded to the valve stem, breaking it into three pieces. A second scope change on this Job Order covered installation of a new nut. Condition Report No. 2-02-89-389 was issued to track corrective and preventive actions.

The inspector reviewed repair documentation and observed and interviewed workmen. Procedures reviewed included:

(1) **12 MHP 5021.001.009 "Installation of Keelaring High Pressure Tube Couplings".

(2) **12 MHP 5021.051.002 "Disassembly, Repair and Reassembly of Hopkinsons 28-inch Steam Generator Stop Valve".

These procedures do not address either the replacement of the hydraulic recirculation/relief valve or the replacement of the stem coupling nut in any great detail. Given the installer's failure to verify the recirculation/relief valve was properly set, it appears this installation contained elements beyond the "skill of the craft" which should have been proceduralized. This is discussed below, in Paragraph 6.d.

The licensee appeared to do a conscientious job of verifying that damage was limited to the obviously broken nut. Other connected or nearby parts were inspected (both PT and VT) by certified Quality Control group nondestructive examiners.

Parts traceability appeared to be properly maintained. A custom part had to be ordered to replace the broken nut, as there were none in stock. The original valve vendor (Hopkinsons) is a European company represented in the United States by Atwood and Morrill Company, Inc. The latter company is on the licensee's qualified suppliers list (QSL) for Hopkinsons valve parts. An engineering safety review determined, however, that the nut could be procured as non-nuclear grade and dedicated. It is not integral to the safety function of the valve. Atwood and Morrill manufactured the replacement nut to the exact dimensions of the original using original supplier engineering drawings and specifications. The material was upgraded from the original BS 1506-621 Grr B to A564-630 HT1100, which has superior tensile and yield strengths.

The upgrade was documented and justified. Purchase Order documentation included traceability information (part and tag nos., material specification and heat no.) and a Certificate of Compliance to the specifications of part no. 29373-447-7176.

d. Job Order No. JO 041480: Check setpoints of relief valves and reset if required. This activity followed c. above, and originally called for setting the relief and recirculation valve set pressure at 1500 psig when issued on February 28, 1989. The set pressure was subsequently revised to 2500 psig and then back to 1500 psig on March 2, 1988, the date of the work observed by the inspector. Attached to the Job Order was a letter from Atwood and Morrill dated March 2, 1989, stating that the correct valve setting was 1500 psig.

The inspector subsequently reviewed the completed Job Order and noted that the as-found relief valve pressures varied from 1350 psig to 2275 psig for the actuators on valves 2-MRV-210, 2-MRV-220 and 2-MRV-230. No as-found data was available on valve 2-MRV-240. Maintenance personnel indicated that no bench testing of new relief and recirculation valves was performed before installation based on the assumption that the valves were pre-set at 1500 psig. This assumption was erroneous, based on the observed failure of the 2-MRV-240 coupling nut and the statement of the Atwood and Morrill technical representative to the inspector.

The activity was conducted using a "Guideline for Setting of Pressure Relief Valves on Hydraulic Actuator", that was prepared and signed by the responsible maintenance engineer on March 2, 1989 and attached to the Job Order. The guideline was not part of an approved procedure nor was it approved by the Plant Manager. The maintenance engineer believed that use of such a guideline was allowed under PMI-2290, "Job Orders".

Licensee procedure PMI-2290, "Job Orders" in Paragraph 4.3.6, requires each Job Order to be reviewed for identification of "appropriate" procedures for use on the job. For skills normally possessed by qualified maintenance personnel, detailed procedures are not required. This parallels Regulatory Guide 1.33, Appendix "A", which the licensee is obligated to follow pursuant to Technical Specification (both Units) 6.8.1.a. Procedure PMI-2290 goes on to indicate instructions or drawings may be used in these cases (even if not mandatory) and, if so, they shall be technically clear and traceable to approval by the Cognizant Engineer.

In the examples of Paragraph 6.b and 6.d above involving 4160 volt. breaker triggering mechanism cleaning and lubrication, and main steam stop valve hydraulic actuator valve setting, each was a unique activity not previously performed at D. C. Cook. Each therefore

involved technical elements outside the skills actually possessed by plant maintenance personnel and a written procedure was required. The "guidelines" documents prepared for these activities appeared to provide technically clear and correct instructions, but they had not been reviewed by PNSRC and approved by the Plant Manager as required by Technical Specification (both Units) 6.8.1.b. This failure to review and approve instructions for performing maintenance beyond the skills possessed by qualified plant maintenance personnel is considered a violation of the referenced Technical Specifications (Violation No. 315/89009-01).

e. Job Order No. JO 015026: Investigate and repair apparent bonnet leak on valve SI-170L2, the safety injection flow path check valve to the loop two cold leg. This valve had failed to seat properly during a previous leak-by test and had been disassembled; the disc and seat lapped and blued, and reassembled. The investigation for an apparent bonnet leak proved unsuccessful, as no leak could be found. The bonnet was retorqued. It may be that condensation dripping into the area from above was being reflashed to steam, giving the appearance of a leak.

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

7. Surveillance (61715, 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 6030 IMP.014 "Protective Relay Calibration". This routine calibration activity was being conducted on breaker T11A7 (Unit 1 West CCW pump power supply) concurrent with breaker maintenance as noted in Paragraph 6.b above. Coordination of these activities served to minimize the duration of the outage required for the associated safety related pump.

b. **2 OHP 4030 STP.027AB, "AB Diesel Generator Operability Test (Train B)". This was a retest to troubleshoot a 10-50v swing on field voltage. It was learned that field flashing was continuous, apparently because of a faulted relay. The inspector questioned personnel concerning applicable limits for operating the diesel

unloaded. The initial answer was that such a run might last up to an hour. The limit is actually 20 minutes, which must be followed by a loaded run of at least 15 minutes. These requirements were properly implemented.

c. **12 THP 4030 STP.218: "Automatic Operation of Auxiliary Feedwater Pumps". The inspector witnessed the portion of the procedure involving AFW system (including feedwater conservation) activation upon receipt of a signal from the ATWS Mitigating System Actuation Circuitry (AMSAC). The AMSAC system was a newly-installed plant modification in Unit 2.

d. **12 THP 4030 STP.097: "Seismic Monitoring Instrumentation Surveillance Test (Monthly)". The inspector observed the initial instrument checks and system functional checks, including a visual check of the accelerometer at the 34KV blockhouse, operation of the recording cassettes, and traces generated from a simulated seismic event. An unusual trace was found on two of the four tapes which showed slightly higher frequency than expected. The shape of the trace was discussed with a vendor technical representative, who indicated there should be no problem with the equipment functioning properly. To be sure, the tapes were sent to the vendor for analysis. The inspector will be made aware of any problems.

e. 1-OHP 4030 STP.011: "Containment Isolation and ISI Valve Operability Test". The data sheets for this procedure specify, among other things, valve number, stroke time, and maximum allowable stroke time. Only successful valve tests (stroke times less than the maximum allowable) were recorded, however. The failures were documented in a small section of the last page by valve, Condition Report, and/or Job Order numbers - without stating stroke times. Unsatisfactory stroke times were recorded only on the referenced Condition Reports, which are processed and filed separately. This practice makes it very difficult to accurately track problem valves and failure trends. The inspector discussed this concern with the appropriate personnel, who said procedure changes are forthcoming such that data on both successes and failures will be documented in one place for each specific valve.

f. The inspector verified proper establishment of Unit 2 containment integrity prior to Unit heatup and entry into MODE 4. Licensee procedure 2-OHP 4030 STP.010, "Containment Isolation" was reviewed, as were the results of licensee performance of the procedure on February 20 and 25, 1989. The inspector verified the status of automatic containment isolation valves from the main control room, and inspected a sample (90 valves) of manual containment isolation valves in the plant. The following were noted:

(1) All licensee documented checks and the inspector's verifications confirmed that isolation valves were properly positioned;

(2) The licensee verifications appeared careful and thorough, both noting the cap outside drain valve 2-RH-136 was not welded as stipulated on Data Sheet No. 3 - an evaluation determined no weld was necessary, so a proper procedure change sheet was processed;

(3) Most items were to be checked for a correct label, but the column of check blanks included items for which a label check appeared inappropriate, such as "visual inspection", "welded caps", "plugged tee", "flange installed", etc. The data sheet of February 20 contained check marks for about 30 such items (mostly on Data Sheet No. 1) whereas the data sheet of February 25 contained the word "No";

(4) Valve PPP-300-V1 off containment penetration CPN-94 was documented as having a label on February 20 and lacking a label on February 25;

(5) The lineup sheets do not verify the presence of a correct label on the penetration - the inspector noted penetration PN-38 lacked a label;

(6) Procedure Attachment I, entitled "CPN Location Guide", provided very useful maps of the relative locations of the containment penetrations in their respective areas. The data sheets were organized to follow the maps with the single exception that CPN-38 and CPN-58 on Data Sheet No. 1 appeared in reverse positions.

The information above, and the observation that a non-boundary valve (BD-103-2) also lacked a label, were provided to the Operations Department for their review and followup action as appropriate.

A comparison check of the Unit 2 containment isolation procedure versus the Unit 1 procedure showed the former had been more recently revised and contained enhanced references and expanded "Limitations" statements and "Instructions".

g. 12 THP 4030 STP.227: "Multiple Entry Personnel Air Lock Leakage Surveillance Test".

Problem Report No. 89-034 was initiated when the Unit 1 650-foot inner airlock door was found to be leaking greater than Technical Specifications (TS) allow. Specifically, the leak rate through the door was measured at 0.6La=140 SCFH while Technical Specifications mandate a rate of no more than 0.5La=116 SCFH. As a corrective measure, the licensee inspected the door and found paint chips and dirt on the seals. They then wiped down the seals and reapplied a qualified lubricant, after which retest showed zero leakage. The inspector was initially concerned whether the licensee's action was simply to show a favorable test result without addressing cause or

being part of a broader preventive maintenance (PM) program performed on a regular basis. The inspector found that such a PM for containment airlock doors does exist, and includes steps for cleaning and lubricating seals and linkages (ref. MHI-530 Task Sheet No. 24). The inspector found no problems with this.

h. **2THP 6040 PER.352: "Rod Worth Verification Tests Utilizing RCC Bank Interchange"

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

8. Fire Protection (71707, 64704)

Fire protection program activities, including fire prevention and other activities associated with maintaining capability for early detection and suppression of postulated fires, were examined. Plant cleanliness, with a focus on control of combustibles and on maintaining continuous ready access to fire fighting equipment and materials, was included in the items evaluated.

During an inspection of maintenance and testing activities on the Unit 2 turbine-driven auxiliary feedwater pump (see Paragraph 9.e), the inspector noted what appeared to be combustible packing/shipping materials (wooden box and pallet) left in the pipeway outside the pump room. These materials were still in the same area the following day.

Licensee procedure PMI-2270 Attachment No. 4 "Control of Combustible Materials" permits bringing shipping/packing materials into safety related areas in specified circumstances, but approval of the Plant Fire Protection Coordinator is required. Such approval had not been granted in the case described above; the Fire Protection Coordinator was unaware of the presence of these materials until advised by the inspector. The procedure also requires immediate removal of such materials on unpacking, which had not been done. The subject materials were immediately ordered removed by the Fire Protection Coordinator. An evaluation of their fire-loading effect on the pipeway and auxiliary feedpump fire zone was performed, which determined the effect to be insignificant. A Problem Report (No. 89-300) was initiated to address longer term corrective and preventive measures as appropriate.

The failure to follow procedure PMI-2270 requirements as described above, constitutes a violation of Technical Specification 6.8.1.f for fire protection program procedure implementation. Due to the rarity and insignificance of this particular violation, and considering the licensee's prompt and responsive corrective actions, the provisions of the NRC Enforcement Policy (10 CFR2 Appendix C) were determined to apply such that no written Notice of Violation will be issued concerning this matter.

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

9. Preparations for Unit 2 Startup (71711)

The NRC consultant continued a review of the licensee's plant startup planning and coordination to determine whether systems disturbed during the outage would be returned to an operable status prior to plant startup and whether plant testing, heatup and startup would be conducted in a controlled manner in accordance with approved procedures. The following observations and concerns were noted:

a. Several walkdowns of primary containment upper and lower volumes were conducted during the report period. Observations were made of: electrical panel boxes with loose or missing screws, clamps, nuts or washers; unattached grounding wires; loose conduit support clamps; a bent cable tray cover which allowed a wrench to slide into the cable tray; and a counterweight on a hydrogen skimmer damper out of position. These observations were brought to the attention of the licensee, who initiated corrective action to resolve the discrepancies.

b. The consultant noted a number of locations where hanger attachments for steam generator instrument piping allowed large (1/2 inch) displacements of the instrument piping while other locations were securely held in place. The observations were at locations where U-bolts were used to secure the line to the hanger support members. No generic concerns were noted with supports utilizing unistrut attachments. The concern was that vibration of the lines during operation or during seismic events could result in damage to or failures of safety-related instrumentation systems. When this was brought to the attention of the Operations Department contact, the NRC consultant was informed that Condition Report No. CR 2-02-89-063 had been initiated on January 14, 1989, addressing similar concerns. Both the condition report and the consultant's observations were made after the completion of the instrument line reinstallation by the Steam Generator Repair Project (SGRP) and turnover back to the plant.

Subsequent discussions with licensee representatives and representatives of American Electric Power Service Corporation (AEPSC) determined that the suspect installation was based on hanger-by-hanger walkdowns done prior to the steam generator replacement outage. These had characterized instrument line routings and hanger details in order to allow reuse of existing hangers and attachments as much as possible. The walkdown information was used to generate hanger design sketches and instrument line isometrics for use in reinstallation procedures and to provide for capture of design information that was previously not well detailed. As part of the design confirmation for the

reinstalled instrument lines, structural calculations were performed for the lines and attachments utilizing current design methods. This resulted in the addition of several supports to ensure that stresses remained within allowable limits under normal operational and upset conditions. Hard supports, or anchor points, were added at the locations where the lines were cut and reconnected to form an interface between undisturbed portions of the lines and their supports and the portions that were disturbed. This was done to provide a lower boundary for the structural confirmation calculations that were performed.

Since the original supports utilized U-bolts that were designed for 1/2 inch small bore pipe as opposed to 3/8 inch, which is the actual size of the instrument piping in Unit 2, the larger size was specified for reinstallation in order to reuse original hanger support members as much as possible. However, the design drawings did not specify a maximum gap to be maintained between the pipe and the U-bolt, thus leading to the noted condition of large gaps of varying magnitudes at many locations. Review of the structural calculations performed for the lines revealed that a maximum gap of 1/16 inch was assumed between the lines and their support members (U-bolt apex or support member).

The discrepancies arose as a result of failure to specify design tolerances and margins for guidance to field installers. It is likely that the original installation had gaps larger than 1/16 inch and that the plant operated that way with no apparent problems. The decision to upgrade the structural calculations appeared prudent, but attention to specific detail was lacking in the design output. As a result, the licensee engaged in an extensive program to remove and reinstall U-bolts which could be adjusted to ensure a maximum gap in accordance with design requirements.

The NRC consultant also noted three hanger locations within the SGRP analysis boundary where 3/8 inch U-bolts were originally used, but design and installation drawings for these hangers specified 1/2 inch U-bolts. The licensee's engineering organization confirmed that design drawings would be corrected to reflect the as-built conditions for these and other hangers where differences might be identified through detailed design walkdowns conducted during U-bolt reinstallation. They also confirmed that design calculations for the associated instrument lines were affected by the different support configuration, but the lines were within the applicable acceptance limits.

Several of the 3/8 inch U-bolts at one hanger location did not have full thread engagement of the second hex nut, while another hanger location outside the scope of the SGRP had inconsistent application of double nutting of the 3/8 inch U-bolts. These conditions were identified to the licensee for appropriate corrective action, and all actions involving hardware were resolved before Unit startup.

c. During walkdown of the supports for the steam generators and the reactor coolant pumps, the licensee identified apparent nonconforming conditions with the support shim fastenings, consisting of welded studs, all-thread couplers, lack of double nuts, improper thread engagements and excessive washer stacks or improper spacers between stud nuts and shim plates. These conditions were reported in Condition Report No. CR 2-02-89-202. The NRC consultant reviewed the CR and the licensee's response to determine if there were failures to follow work instructions or other violations of procedures.

The SGRP performed a detailed field walkdown of all steam generator lower lateral and reactor coolant pump shim locations to confirm conditions and quantify problem areas for corrective action. It was determined that the deficiencies found were, for the most part, conditions existing prior to SGRP replacement activities. No records could be found that would indicate how the conditions occurred initially. Some of the shims were worked by SGRP personnel; they identified several of the noted conditions, such as loose nuts and lack of double nuts, or lack of full-thread engagement. Work on the shims had not been completed at the time the Condition Report was written.

The corrective action specified was performed under Job Order No. 028750 and involved replacing welded studs and studs with incorrect lengths, and tightening nuts or adding nuts where determined necessary. The licensee's corrective actions appeared appropriate.

d. During the heatup and preparation for mode change from Mode 4 to Mode 3, the East Residual Heat Removal (RHR) Heat Exchanger relief valve SV-104E lifted at 320 psig primary system pressure (about 500 psig at the valve) and did not reseat until primary system pressure was below about 250 psig. This resulted in the discharge of approximately 5000 gallons of primary coolant into the pressurizer relief tank, rupturing of the rupture disc, and subsequent discharge to the containment sump. Cooldown and depressurization of the plant was required to replace the valve. Valve SV-104W on the West RHR train was also removed and replaced. Both valves were replaced with tested valves.

Subsequent investigation by the licensee included a bench test where SV-104E had a lift pressure of 280-290 psig instead of 600 psig. Disassembly of the valve revealed a bent spindle, metal shavings around the springs due to galling, and a pit on the seating surface. Valve SV-104W had a lift pressure within tolerance and reseated properly, but it was noted that the spindle was slightly bent. Both of these valves were gagged during the hydrostatic testing of the RHR system, and the licensee believed that the gagging may have been

responsible for the observed damage. Previous hydrostatic testing on Unit 1 had not resulted in similar problems, but the licensee stated that the hydrostatic test procedures would be re-examined to ensure the potential for valve damage is minimized.

e. The Turbine Driven Auxiliary Feedwater (TDAFW) Pump had a number of repairs and refurbishments made to it during the outage, including refurbishment of the linkage between the governor and the governor valve, installation of a completely new governor valve and installation of a new governor. The NRC consultant witnessed the initial roll of the TDAFW pump on March 1, 1989, and observed no apparent problems other than adjustment of linkage and correction of a short in the electronic overspeed probe. The pump was set up for overspeed trips and final maintenance checkout on March 5, and turned over to Operations for testing (procedure STP.017T) to determine operability. The initial start under the Operations STP resulted in some cycling of the governor valve at slow speed prior to settling out and ramping up to full speed. When the pump reached full speed, the governor valve cycled significantly several times and the pump tripped on overspeed. A restart was attempted with essentially the same results, and the test was aborted.

   Subsequent maintenance troubleshooting determined that the newly installed governor was not acceptably controlling the governor valve, and a rebuilt governor was installed from stock. The performance of this governor was determined to be acceptable, and the performance of STP.017T was successful on March 7, 1989. It was noted that the plant was in a 72 hour Technical Specification action statement due to the TDAFW pump being inoperable; operability was declared approximately one hour before expiration of the action time. Actions taken by the licensee to resolve this problem were prudent, and the consultant was not concerned that the imminent expiration of the ACTION time caused the licensee to make any decisions adversely affecting safety.

f. A specific tour was conducted throughout areas of the Unit 2 turbine building which had been in use for "temporary" storage of contaminated materials associated with the completed Unit 2 steam generator repair project. This tour verified the licensee had fulfilled his commitment to remove all such materials and restore the turbine building to a radiologically "clean area" status prior to Unit startup.

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

10. <u>Testing of Unit 2 Plant Modifications (72701, 37828)</u>

A sample of plant modifications (Request for Change (RFC) Packages) and the associated testing were reviewed to determine whether the

modifications were properly tested prior to being placed in service. The following RFC packages were selected for review:

RFC 2868 Modify Electrical Switchgear Ventilation System.
RFC 2873 Turbine Trip AMSAC (ATWAS Mitigating System Actuation Circuitry).
RFC 2903 Replace AFW Regulating Valves

The following observations and deficiencies were noted as a result of the reviews.

a. RFC 2868

The NRC consultant observed a portion of the post-modification testing for RFC 2868, using procedure **12 THP 4030 STP.225.051, "Emergency Safety Switchgear Room (East 600V SWGR Room and Mezzanine Area) CO_2 Fire Suppression Test." When a jumper was installed per Step 5.5.41 to actuate the header inlet valve, the expected sequence did not occur. The valve was subsequently activated manually, releasing the carbon dioxide charged into the portion of the header under test, and it was observed that all damper, fan and fire door actuations occurred as designed.

Subsequent review of the test failure revealed that actuation required a signal from a flame detector coincident with the ionization detector signal simulated by the jumper installed. The procedure was revised to include a simulated flame detector actuation signal. When elementary wiring diagrams and termination drawings were reviewed by the individual revising the procedure, the need for coincident actuation of two relays was missed. It appeared to the NRC consultant that part of the problem was due to difficulty in reading the termination print. Action was also initiated to review other carbon dioxide system test procedures to ensure planned revisions were correct.

b. RFC-2903

This modification changed out the Auxiliary Feedwater System regulating valves and replaced them with new valves of a different design to reduce wear during throttling operations of the AFW System. This modification had been previously completed on Unit 1. As part of the post-modification testing requirements, test procedure STP.247 was specified to ensure proper flow through the valves under flow retention situations.

The NRC consultant reviewed the Unit 1 version of STP.247, since the Unit 2 version had not yet been approved, and noted that the flow retention position of the valves was achieved by simulating a high flow signal on pump discharge flow. This simulated signal drove the

valves to the flow retention position before the pump in test was started. Following pump start, flow balancing was performed and the valve positions adjusted to the requirements of the procedure.

The consultant was concerned that the movement of the valves was performed without flow through the valves, thereby not simulating actual flow conditions. When questioned, the licensee stated that high differential pressure testing had been performed on the valves using the MOVATs methodology, thereby giving assurance that they would operate properly under expected flow conditions. Additionally, operating experience on Unit 1 with the identical valves revealed low torque switch settings that were increased to avoid valve operability problems, and this experience had been factored into Unit 2. The consultant was satisfied that the Unit 2 valves would operate as designed based on the information provided by the licensee.

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

11. Complex Unit 2 Surveillance Testing (61701)

Surveillance testing plans, procedures and test data were reviewed and portions of complex surveillance tests were witnessed. Tests were reviewed to verify that the procedures were properly approved, met applicable technical, regulatory and administrative requirements and were properly performed. Test data from completed tests were reviewed to ensure proper data reduction was performed, independent verifications were made and acceptance criteria were met. Tests reviewed and observed (in part) were:

- **2 THP 4030 STP.217A, "DG CD Load Shedding and Performance," Revision 5.
- **2 THP 4030 STP.217B, "DG AB Load Shedding and Performance," Revision 5.
- **2 THP 4030 STP.205A, "Engineered Safety Features Time Response Test Train A," Revision 13.
- **2 THP 4030 STP.205B, "Engineered Safety Features Time Response Test Train B," Revision 12.
- **2 OHP 4030 STP.007E, "East Containment Spray System Operability Test," Revision 7.
- **2 OHP 4030 STP.007W, "West Containment Spray System Operability Test," Revision 4.
- **2 OHP 4030 STP.051N, "North Safety Injection Pump System Test," Revision 3.
- **2 OHP 4030 STP.051S, "South Safety Injection Pump System Test," Revision 3.
- **2 OHP 4030 STP.050W, "West Residual Heat Removal Train Operability Test - Modes 1-4;" Revision 2.
- **2 THP 4030 STP.226, "Reactor Coolant System Pressure Isolation Valves Leakrate Test," Revision 6.

- **2 OHP 4030 STP.008, "Emergency Core Cooling System Cold Shutdown Test," Revision 6.
- **2 OHP 4030 STP.017T, "Turbine Driven Auxiliary Feedwater System Test," Revision 7.
- **2 OHP 4030 STP.017R, "Auxiliary Feedwater Pump Response Time," Revision 3.
- **2 OHP 4030 STP.019F, "Steam Generator Stop Valve Operability Test," Revision 0.
- **12 THP 4030 STP.218, "Automatic Operation of Auxiliary Feedwater Pumps," Revision 12.
- **12 THP 4030 STP.206.2, "Surveillance Test Procedure - Electric Hydrogen Recombiner No. 2," Revision 2.

The following findings and observations were identified during these procedure reviews and test performance witnessing:

a. Performance of blackout testing per STP.217A and STP.217B was completed during this inspection period by performing retests of equipment items that were out of service during the major portions of the testing conducted earlier and reported in Inspection Report No. 50-316/88031(DRP). A review of STP.217B test results by the NRC consultant identified the following discrepancies and questions:

(1) In Section 7.0, Acceptance Criteria, Step 7.2, the engineer noted that safety injection was manually initiated from the Control Room pressurizer panel instead of the safety injection panel in test Section 5.3 and was initiated from the safety injection panel instead of the pressurizer panel in test Section 5.5. Review of Step 5.3.18 and Step 5.5.16 indicated that this reversal had been made. No procedure change forms were found to effect this change. The performance engineer stated that the methods of initiation were reversed for testing convenience and that no difference in the test results occurred since the initiating signals were identical. Although the intent of the procedure was not changed, which would require a procedure revision, a change sheet for an "on-the-spot" change was not initiated in accordance with procedure PMI 2010. This appears to be an example of less than strict adherence to procedures in order to accomplish the work activity.

(2) Step 7.7 confirmed that the AB diesel generator had the capability to reject load while maintaining voltage and frequency within specified limits of Technical Specification 4.8.1.1.2.C.3. Confirmation of frequency was made by relating the engine speed to frequency and measuring speed during the load rejection test. The speed determined from the recorder charts was noted in the margin by the test engineer rather than in a specified space for the value. Step 7.7 only required signoff that the Technical Specification was met. Also, no signoff for independent verification of the speed determination was present in the procedure.

(3) Step 5.2.13 directed the performance engineer to ensure that the diesel generator reached rated speed in 10 seconds or less. The procedure did not have a space for recording the time to reach rated speed, nor was this calculation independently verified. Again, the time to reach rated speed was noted in the margin by the test engineer. The NRC consultant reviewed the test data and confirmed the noted value.

The test engineer's supervisor concurred with the NRC consultant's findings and indicated that enhancements to the test procedures would be made prior to the next performance of the tests and that test engineers under his supervision would be counseled in the proper methods to revise procedures.

b. Operability of the Containment Spray System is verified by the Containment Spray pump developing a discharge pressure of 255 psig or greater at a flow of 700 gpm or greater while on recirculation flow, in accordance with Technical Specification 4.6.2.1.a. Step 8.29 of STP.007W directed the operator to adjust flow to within maximum and minimum flow values specified by ISI Data Figure 15.1 (via manual recirculation valve 2-CTS-105W) and to record the flow from flow gauge 2-IFI-245. Recording of the discharge pressure was obtained in Step 8.33 once the flow value was established. The inspector noted that the values used in the procedure for maximum and minimum flows were related to the meter scale, which was 0 to 100 divisions rather than actual flow in GPM. The band for minimum to maximum flow was 77 to 81, relating to 700 to 724 GPM actual flow. This correlation was obtained from the ISI data figure referenced above. Following adjustment of the recirculation line manual valve by the operator, the inspector noted that the gauge indicator oscillated irregularly over a band of 10 to 20 or more divisions, requiring visual averaging of the oscillations to arrive at the value of the recorded flow. The inspector was concerned that the accuracy required for establishing the flow could not be ensured by the operator using the installed flow gauge, and that Technical Specification compliance or pump performance changes could not be sufficiently assured. The Operations engineering supervisor advised that an investigation would be made to determine if modifications could be made to minimize the oscillations observed on the installed gauge or if other instrumentation were available to increase the accuracy of the flow measurement. This is considered an Open Item (No. 316/89009-01) pending licensee review and resolution of this matter.

c. Operability of the Safety Injection System is verified by the Safety Injection pumps developing a discharge pressure of 1445 psig or greater while on recirculation flow, in accordance with Technical Specification 4.5.2.f. Step 8.16.2 of STP.051S directed the operator to use pressure data from Steps 8.14.2, pump running suction pressure, and 8.15.1, pump discharge pressure, to calculate

the pump differential pressure in psig for comparison with ISI requirements. While reviewing the test results following completion of the test, the NRC consultant noted that the operator erroneously entered running suction pressure from Step 8.14.3, which calculated the pressure in psia, instead of the data from Step 8.14.2. The resultant differential pressure was low by 14.7 psid, but was still within the ISI action levels. The inspector observed that the completed test procedure was reviewed by two separate Operations control room supervisors and by an Operations staff individual without discovering the error.

d. Operability of the main steam stop valves is verified by the performance of STP.019F to ensure that closure times are within the limits specified in the ISI data book. During testing of stop valve No. 2-MRV-210, the Train A test resulted in a closure time in excess of the ISI requirement (4.8 seconds vs. the required 4.2 seconds). When testing of Train B was attempted, dump valve 2-MRV-212 cycled as required, but the stop valve did not move. Cycling of the three-way test valve 2-MMO-210 was attempted, but the problem could not be corrected. The licensee closed the stop valve using its control switch and declared the valve inoperable. Testing of the other three stop valves was successful, with all closure times being well within the ISI and Technical Specification limits.

Three-way test valve 2-MMO-210 had been removed during the outage and returned to the valve manufacturer, Atwood and Morrill, for repair and refurbishment. Initial investigations indicated valve internal problems, which required the plant to return to Mode 4 and repair the valve since it could not be repaired under secondary plant pressure conditions. These repairs were completed successfully on March 12, 1989.

Performing this repair revealed valve internal damage had occurred, and that the valve had been installed with an incorrect orientation such that a steam outlet port was aligned for steam inlet. Problem Report No. 89-284 documented the incorrect orientation (basically, the valve was welded in the line backward) of this three-way valve, as well as the fact that licensee and vendor drawings seemed to show opposite orientations from each other. Since there were a variety of complications leading up to the error, and several questions remained unanswered, the licensee deisignated the subject Problem Report for evaluation by the Human Performance Evaluation System process. The licensee agreed to inform the inspector on the outcome of the evaluation.

No violations, deviations, or unresolved items were identified. One open item was noted involving a test procedure tolerance finer than than the test gauge can meet.

12. Followup on Unit 2 Startup Concerns (92701)

Inspection concerns initially identified in NRC Reports No. 50-316/88031(DRP) and No. 50-316/89002(DRP) were subject to continuing inspection during this inspection period.

a. During performance of Procedure ISI.038, involving secondary plant hydrostatic testing, several problems occurred. These were documented in licensee Condition Reports (CR) No. 2-11-88-1510, No. 2-11-88-1572 and No. 2-11-88-1574, which indicated weaknesses in test control and communication. The responses to the condition reports were reviewed to ensure that the root cause for the occurrence of the conditions was properly identified and that appropriate corrective and preventive actions were taken or planned.

The installation of test equipment to incorrect system connection points (CR 2-11-88-1572) was attributed to failure of the involved Hydrostatic Test Coordinator to have the procedure in hand when verifying the installed equipment location. A contributing factor, which was not identified in the condition report, appeared to be a lack of concise, written direction by the Test Coordinator to the craft personnel installing the test equipment as to the specific location for the equipment. The preventive action specified in the report related to proper procedure verification and human factor improvements in hydrostatic test procedures. This appeared to be appropriate for closure of this concern.

Isolation of a test gauge by a temporary valve (CR 2-11-88-1510) was attributed to failure of the contractor assigned to install the test gauge to be aware of the Hydro Engineer's policy of not using isolable test gauges during hydro testing. The engineer stated that this policy was unwritten, and had not been specifically communicated to the involved contractor. The preventive action identified in the CR only addressed the discussion of the policy with the contractor. The inspector was concerned that no commitment was made to make this a written policy. The Hydro Test Engineer and the Operations Superintendent stated that a hydrostatic test control document was being developed, and that this policy would be incorporated as part of the document to better ensure that the problem would not recur.

Disconnecting the test pump high pressure hose by non-test personnel and shutdown of the demineralized water pump during performance of the test (CR 2-11-88-1574) was attributed to weaknesses in coordination of activities. Multiple personnel were involved in many evolutions directly and indirectly related to the test, and impacting on its successful completion. Discussions with the Operations Superintendent revealed that several of the Hydro Test Coordinators may not have been sufficiently trained in the

administrative duties of test coordination such as shift briefings and other aspects. The licensee committed to improve training for coordinators in the future to ensure that proper coordination would be achieved.

With the additional commitments identified above, the corrective and preventive actions for these Condition Reports was considered acceptable.

b. During performance of blackout testing per STP.217B, Section 5.5, the Non-Essential Service Water (NESW) pumps restarted when the containment spray signal was reset. The procedure data sheets (Attachment 5.5) specified that the pumps should not have restarted. Investigations by the Performance Department indicated that the pump logic performed in accordance with the respective schematic drawings for Unit 2 and that the same logic and schematics were appropriate to Unit 1. Prior testing results from an earlier revision of this procedure on Unit 2 revealed that pump restart was called for by the procedure. Apparently, the data sheet was incorrectly changed in the latest revision. Review of Unit 1 testing, performed between the two subject Unit 2 tests revealed that the data sheet called for the NESW pumps to remain off, contrary to pump logic requirements. The test engineer could not identify the source of the change, except perhaps due to a typographical error. The data recorded by the performance technician indicated at the time that the pumps did remain off, in accordance with the procedure; however, re-review by the Performance Department of data recordings indicated that the pumps did in fact restart, in accordance with design. The failure of the technician to note the restart was attributed to the presence of a timing relay in the restart circuitry between containment spray signal reset and initiation of the starting of the NESW pumps. Thus, completion of breaker status recording prior to timeout of the subject relay could have resulted in the observation that the pumps remained off.

An investigation of the effect of NESW pump restart on diesel generator loading was conducted by American Electric Power. The conclusion was that the NESW pumps would place an additional 210 kw load on the diesel generator, resulting in a cumulative load of 3550 kw. Compared to a 2000 hr rating of 3650 kw and a 2 hr rating of 3850 kw, this load would not adversely affect the generator. The recommendation was made to shed non-essential loads in accordance with plant Emergency Operating Procedures to maintain loading below 3500 kw. The resolution of this condition was found to be acceptable.

c. Procedure ISI.002, involving primary system hydrostatic testing, required inspection of the lower reactor vessel head and attachments accessible via the reactor cavity. When the QC inspectors reached the reactor cavity, radiation levels of 5 - 10 R/hr were encountered and that portion of the inspection was aborted. The procedure had

not anticipated the incore flux thimbles being positioned in the reactor cavity and provided no prerequisite checks nor specific coordination with radiation protection personnel. Problem Report No. 88-849 was issued documenting the unexpected dose levels. The NRC consultant reviewed the investigation of the CR, which determined that the area was posted as a high radiation area with a B-8 lock, indicative of the incore flux thimbles being inserted, as opposed to being posted as an extreme high radiation area with a B-7 lock, indicative of the thimbles being in a withdrawn position. The area had been posted correctly as an extreme high radiation area as late as June 16, 1988, according to Radiation Protection records. On June 20, 1988, responsibility for radiation protection in containment was turned over to the Steam Generator Replacement Project which included routine surveys and radiological postings. A review of SGRP records did not reveal any information on the posting status of the reactor cavity underneath the vessel. The SGRP still had responsibility for the postings and surveys at the time of the aborted test. The investigation concluded that the posting was changed in a non-conservative direction sometime between June 16, 1988, and November 23, 1988, but could not determine how or why. This resulted in an apparent violation of the posting requirements established by licensee procedure. NRC Region III specialist inspectors were requested to review this licensee-identified violation during their next routine inspection. Corrective action was immediately initiated to correctly post the area as an extreme high radiation area. Corrective action was not addressed, however, for the failure to account for the thimbles being in the withdrawn condition in Procedure ISI.002 and subsequent actions to be taken. Discussions with the licensee concerning this point resulted in the commitment to incorporate directions into ISI (or other) procedures requiring entry under the reactor vessel, regarding verifying the position of the incore detectors.

d. Condition Report No. CR 2-11-88-1628 documented the malfunction of pressurizer safety valve SV-45C during the performance of Procedure ISI.002 resulting in leakage or lifting of the valve. The licensee removed SV-45C and also SV-45B, since there was some indication that this valve might also be leaking, and sent them to Wyle Laboratories for testing. The testing of SV-45C revealed indications of leakage at 2236 psig but valve set pressures were within Technical Specification requirements. The valve was lapped, retested and found to be acceptable.

Valve SV-45B was tested initially for leakage and none was found. When the set pressure test was conducted, the initial lift was 16 psig out of tolerance high but three subsequent lifts were within the required range. A leakage test following the set pressure tests showed some leakage. As was the case with the other valve SV-45B was lapped, retested and found to be acceptable. The out of tolerance condition was reported in a LER by the licensee.

e. RFC 2770 involved replacement of a diode in the TDAFW pump trip circuitry with a resistor, affecting a number of circuit terminals. The NRC consultant had determined, as reported in NRC Report No. 50-316/88031(DRP), that the surveillance tests planned to test the adequacy of the installation did not functionally test all the affected circuits as recommended by AEPSC engineering. The design change coordinator advised that functional checkouts would be performed and documented. Job Order No. JO 030012 was completed on February 2, 1989, and review of this Job Order confirmed that all affected circuits performed as designed.

f. During performance of Procedure ISI.038 for hydrostatically testing the secondary system, the main steam safety valve gags would not stay in place, causing several of the valves to simmer and/or lift, causing a concern for potential valve damage. The licensee chose to not disassemble the valves, but to observe them for misoperation or leakage during the heatup for plant startup and to conduct setpoint testing prior to restart. The subject valves that were observed to have problems were declared inoperable. Operable valves were interchanged between loops to meet the requirements of Technical Specification 3.7.1.1.a and allow heatup to Mode 3 conditions to allow testing of the valves.

The NRC consultant observed the Trevi testing of four of the inoperable safety valves conducted on March 8, 1989, on steam generators 21 and 24. Set pressures were observed to be slightly out of tolerance on several of the tested valves, requiring adjustment of the spring tension. No anomalous conditions such as leakage, chattering or sticking were observed. Slight steam leakage observed prior to testing disappeared after the testing was conducted. It appeared that the gagging difficulties experienced during the secondary hydrotest did not result in significant problems with the subject safety valves.

g. As a followup to the problem encountered in performing the inspection of the lower reactor vessel head and attachments during the primary system hydrotest discussed in c. above, the licensee completed the remaining portion of Procedure ISI.002 on March 7, 1989. Pressure conditions were established and maintained during the test, and no primary system leakage was observed in the area underneath the vessel. A full RCS leakage inspection in accordance with ISI.050 was conducted in conjunction with the completion of ISI.002 and found minor packing leaks but none of significance. The RCS leakrate as reported on March 8, 1989, was 0.13 gpm.

h. It was noted during prior inspections by the resident and Region III inspectors that the reactor cavity water in which the control rod drive shafts were stored had significant surface contaminants and dirt from construction activities related to the SGRP. Although the shafts were acceptably cleaned prior to reinstallation, the NRC

consultant reviewed the results of control rod drop testing to determine if residual effects of the work activity would unacceptably affect drop times or control rod accelerations. The test data showed that all drop times were within allowable limits and no anomalous behavior was evident. It appears that no adverse affects on the operability of the control rods resulted from the SGRP activity.

In summary, the licensee preplanned and executed a logical, thorough, well-documented program for Unit 2 return-to-service following the extended SGRP outage, as discussed in Paragraphs 9 through 12 of this report and in the referenced previous reports. When problems were encountered, they appeared to receive adequate attention at appropriate levels of management, and they were satisfactorily resolved. Occasional instances were noted involving imperfect procedure adherence, or communication/coordination lapses, during heavy focus on getting a job done. No case compromised the end result. The special NRC inspection emphasis on various aspects of the Unit 2 return-to-service program is considered complete.

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

13. Reportable Events (92700, 92720)

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and, as applicable, that immediate corrective action and appropriate action to prevent recurrence had been accomplished.

a. The following Licensee Event Reports (LERs) are considered "Closed" based on NRC Region III management administrative review and instructions to the inspector; they are documented here, per those instructions, for traceability:

(1) LER 315/86004-LL: partial loss of safety related electrical equipment due to improper application of motor control center reversing starter control transformer;

(2) LER 315/86022-LL: personnel error results in failure to revise rod insertion limits following technical specification amendment;

b. (Closed) Licensee Event Report (LER 315/88008-LL): the hydrogen skimming system had mispositioned dampers, reducing system capability. This condition was identified by the NRC and was the subject of a Notice of Violation as discussed in Paragraph 2.b above. As also discussed above (Paragraph 2.c) an evaluation showed system capability was not so compromised as to permit post-accident hydrogen to accumulate in explosive amounts. Licensee corrective and preventive actions documented in the LER and in the response to the Notice of Violation appeared adequate.

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

14. NRC Circular (92703)

The inspector reviewed the NRC communications listed below and verified that: the licensee has received the correspondence; the correspondence was reviewed by appropriate management representatives; a written response was submitted if required; and, plant-specific actions were taken as described in the licensee's response.

(Closed) I.E. Circular 78018-CC. This item is being closed based on NRC Region III management review and is so documented here for traceability.

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

15. Followup on Plant Events (93702)

The following plant events, some of which involved licensee notifications to NRC pursuant to 10 CFR 50.72, were reviewed to assess compliance to reporting requirements and to verify appropriate corrective and preventive actions were taken or planned.

a. On February 24, 1989, plant personnel discovered a small leak in one of Unit 2's main turbine lubricating oil coolers. Lake water from the nonessential service water (NESW) system flows through the cooler tubes to remove heat from the lube oil. A small puncture through the tube completed a path to the NESW system which, in turn, discharges to Lake Michigan. The leaking cooler was isolated and the tube plugged. Eddy current testing was performed to determine the integrity of the remaining cooler tubes.

   The exact amount of oil lost is not known, but 1156 gallons of lube oil were added to the tank to bring the level back up to the normal level. No oil was observed at the plant water discharges, nor along the shore or on the ice surrounding the discharges. Due to the very dangerous nature of lake ice no attempt was made to walk out on the ice for a close inspection.

   Both Federal and State environmental personnel were notified.

b. On February 16, 1989, with Unit 2 in MODE 5 during a reactor coolant system (RCS) fill and vent procedure, a pressurizer relief tank (PRT) rupture disk lifted, releasing approximately 5000 gallons of a mixture of RHR system and primary water into the unit's containment sump. This event is discussed in more detail in Paragraph 9.d above.

c. On February 27, the plant reported discovery of a potentially unanalyzed condition relating to the storage of three 500-lb. load blocks in the containment ice condensers in each Unit. These "weights" are used for checking the load cells used in ice basket

weighing. Procedures have long called for tieing the weights down, in place, during periods of plant operation. The basis for acceptability of this practice could not be documented when questioned by the Unit 2 containment closeout inspection crew. Subsequently, Unit 1 entered a 48-hour LCO, a document search was initiated, and crews were dispatched to remove the weights from both containments. This was completed some nine hours after identification of the problem.

d. Upon being informed during an NRC Region III inspection that his local leakrate testing calculational methodology (minimum pathway) was not valid for demonstrating regulatory compliance, the plant recalculated as-found Unit 2 outage data from April 1988, when local leakrate testing was performed using the methodology. The recalculation determined, on February 21, 1989, that the "as-found" leakage exceeded 0.6 La, so a notification to that effect was made.

A successful integrated leak test was completed February 12. All local leakrate tests had been repeated in the weeks preceding the integrated test. Recalculation on the repeat local tests showed "as-left" leakrate totals well below 0.6 La.

NOTE: La is the maximum allowable leakage rate (in percent of containment air weight per 24 hours) at the calculated peak containment internal pressure related to the leakage design basis accident.

e. In mid-January, inconsistencies were found with regards to small bore piping supports on Unit 2 steam generator instrument and sample lines. The concern was that in some cases, this condition could stress the lines and result in premature wear and degradation. For this reason, the plant replaced all supports (approximately 310) on each steam generator. This situation is discussed in more detail in Paragraph 9.b above.

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

16. Region III Requests (71707, 255100)

a. During this inspection period the inspectors received a Region III request to have the licensee review their records to determine whether certain fasteners, manufactured by Hardware Specialties Co. (HSC) and purchased between 1980 and 1985, were installed or stored on site. It is suspected that HSC certified the fastener material, purchased from intermediary suppliers, without performing the applicable verification activities or upgrade testing.

The plant found two instances when the suspect fasteners were purchased. In one case, 12 bolts for use in control rod drive mechanism duct supports were found (ref. purchase order No. 82C34705)

and in the other, 70 bolts were found for use in a reactor support cooler/sand plug assembly (purchase order No. 82C34690). Both purchases were made in 1985. Other material was purchased from the company in 1980, 1982, 1983, and post 1985, but either the material was not 304SS or the purchase order was outside the time frame of concern. The Hardware Specialties Company is presently off the licensee's Qualified Suppliers List.

NRC Information Notice No. 89-22 "Questionable Certification of Fasteners", issued March 3, 1989, was provided to alert licensees to the certification problem of fasteners furnished by the aforementioned company.

b. By letter dated January 17, 1989, from E. G. Greenman, Director, Division of Reactor Projects, the inspector was requested to verify the licensee's Quality Assurance (QA) program for the emergency diesel generator (EDG) fuel oil storage and delivery system. The inspection guidance is contained in NRC Inspection Manual TI 2515/100, dated November 25, 1988. By a similar request, the inspectors had previously verified the licensee's QA program for the EDG fuel oil alone (ref. NRC Inspection Reports No. 50-315/88014(DRP); 316/88016(DRP)).

The inspector's findings concerning the EDG fuel oil storage and delivery system included the following:

- Day tanks are sampled monthly for water by either low point or dip (sample thief) sampling methods; any accumulated water is removed as soon as practical.

- Fuel oil bottom sampling and analysis are performed to detect high particulate concentrations due to the effects of oxidation and biological contamination in accordance with ASTM-D270-65 (reapproved in 1980).

- Additives are not added to the fuel oil to inhibit bacterial growth, as the supplier recommends maintaining water content $\leq$0.05 ppm as the best method to prevent bacterial growth.

- The fuel oil system utilizes a duplex filter between the day tank and the engine, and bypass capability is provided between the storage and day tanks. This permits on line cleaning of the elements in the event of fouling.

- Fuel oil filters and strainers are inspected and cleaned or replaced on an 18-month frequency per manufacturer recommendations.

- Differential pressure gauges are provided on all filters with alarms annunciated individually on Control Room panels.

- A pending Technical Specification change will require fuel oil storage tanks to be cleaned at least once every ten years to remove accumulated particulates.

It appears that the licensee has adequately addressed EDG fuel oil storage and delivery systems in his QA program.

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

17. Open Items

Open Items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. An Open Item disclosed during the inspection is discussed in Paragraph 11.b.

18. Management Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on March 22, 1989, 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 development, implementation, and outcome of expanded preventive maintenance activities on reach-rod operated manual valves (Paragraph 6.a);

b. The use of guidelines vice reviewed, approved procedures for conducting maintenance activities, including the specific examples involved in the identified Violation (Paragraphs 6.b and 6.d);

c. An apparent minor violation of fire protection procedures (Paragraph 8);

d. General results of NRC inspection, now concluded, of the Unit 2 restart program (Paragraphs 9 - 12);

e. Inspector followup activities on plant events or on requests from NRC Region III (Paragraphs 15 and 16).