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Executive Summary

D. C. Cook Units 1 and 2
NRC Inspection Report No. 50-315/97009(DRP); 50-316/97009(DRP)

This was a special Operational Safety Team Inspection (OSTI) conducted to determine the scope and magnitude of recent problems with procedure adherence and adequacy, the conduct of operations, and material condition. The inspection included a review of operations, maintenance, and engineering.

Operations

- Overall, command and control of control room activities was good. An exception was noted when an essential service water valve was mispositioned from the Unit 1 control room and was not noticed until the start of the next shift, about 12 hours later (Section O1.1).

- Three control room annunciator response procedures did not accurately reflect current practices. The licensee corrected the procedures (Section O1.1).

- On May 5, 1997, the licensee failed to observe reactor coolant system average temperature (Tavg) every 30 minutes with the low Tavg alarm inoperable as required by TS 4.1.1.5.b. A non-cited violation for this failure to follow TS requirements was identified (Section O1.2).

- During observations of in-plant activities, the inspectors noted that, overall, the auxiliary equipment operators performed their duties well and that material condition in the auxiliary building was good (Section O1.3).

- Station management efforts to increase the number of plant problems documented in condition reports have been successful. Other efforts to improve the corrective action program were just being implemented (Section O1.6).

- The Unit 2 AB emergency diesel generator inverter was improperly removed from service when an addition to a clearance for troubleshooting the voltage regulator was made. A violation was identified for failure to follow the procedure (Section O2.1).

- During walkdowns of the essential service water, component cooling water, and the auxiliary feedwater systems, the inspectors observed discrepancies involving equipment nomenclature in procedures, labeling of flow diagrams, and sealed valves. Two non-cited violations were identified. The licensee made three commitments to rectify these discrepancies (Section O3.1).

- Problems with procedure adherence continued, although some improvement was evident (Section O3.2).

Maintenance

- Workers reinstalling the Unit 2 AB emergency diesel generator (2AB EDG) manual voltage regulator card failed to properly tighten the connections, leading to a failure of the voltage regulator during testing. The extended troubleshooting required to identify the root cause and repair the voltage regulator resulted in the licensee shutting down Unit 2. A non-cited violation was identified for failure to follow procedure (Section M1.2).

- The initial troubleshooting into the 2AB EDG voltage regulator failure was weak and did not identify two failed silicon controlled rectifiers. This delay contributed to the need to shut down Unit 2 (Section M1.3).

Engineering

- Seven temporary modifications exceeded the licensee's administrative time limit for resolution. A procedure violation was identified (Section E2.1).

- Of four modification packages reviewed by the inspectors, discrepancies were identified in three. A violation was identified involving inadequate translation of design requirements into design documents (Sections E7.1 - E7.4).

TABLE OF CONTENTS

O1 Conduct of Operations ... 1
- O1.1 Control Room Observations ... 1
- O1.2 Missed Unit 1 Surveillance of Reactor Coolant Temperature ... 3
- O1.3 In-plant Observations ... 4
- O1.4 Annunciator Response Outside the Control Room ... 5
- O1.5 The Focus of Station Operations ... 6
- O1.6 Corrective Actions Program ... 7

O2 Operational Status of Facilities and Equipment ... 8
- O2.1 Equipment Out-of-Service Control ... 8
- O2.2 Operator Workarounds ... 10

O3 Operations Procedures and Documentation ... 10
- O3.1 Engineered Safety Feature Walkdowns ... 10
- O3.2 Procedural Adherence ... 13

O4 Operator Knowledge and Performance ... 14
- O4.1 Non-Essential Service Water Pump Breaker Would Not Trip ... 14

M1 Conduct of Maintenance ... 16
- M1.1 Surveillances ... 16
- M1.2 Unit 2 AB Emergency Diesel Generator Planned Maintenance ... 16
- M1.3 Unit 2 AB Emergency Diesel Generator Voltage Regulator ... 18

M2 Maintenance and Material Condition of Facilities and Equipment ... 20
- M2.1 Minor Maintenance Program ... 20

E2 Engineering Support of Facilities and Equipment ... 22
- E2.1 Temporary Modifications ... 22

E7 Quality Assurance in Engineering Activities ... 24
- E7.1 Installation of a Vent Line in the Safety Injection System ... 24
- E7.2 Auxiliary Feedwater Flow Retention Circuit Design Change ... 25
- E7.3 Replacement of EDG Air Start System Safety Valves ... 28
- E7.4 SI Pump Discharge Safety Valve Setpoint Decrease ... 29

X1 Exit Meeting ... 31

PARTIAL LIST OF PERSONS CONTACTED ... 32

ITEMS OPENED AND CLOSED ... 34

LIST OF ACRONYMS ... 35

Report Details

Summary of Plant Status

Unit 1 had recently completed a refueling outage and was at about 98 percent power during the first several days of the inspection and at 100 percent reactor power for the remainder of the inspection.

Unit 2 was at 100 percent at the start of the inspection and reduced power to subcritical on May 9, 1997, because of an inoperable emergency diesel generator (due to a faulty voltage regulator). Unit 2 resumed 100 percent power operation on May 17, 1997, after the regulator was repaired.

I. Operations

O1 Conduct of Operations

O1.1 Control Room Observations

a. Inspection Scope

The inspectors spent numerous hours in the Unit 1 and 2 control rooms, including a continuous 72-hour period during the first week of the inspection. Activities observed included the cooldown after a shutdown because of an inoperable Unit 2 AB emergency diesel generator (2AB EDG) and mode change to resume power operations after EDG repairs, control room support of EDG and valve actuator testing, a main turbine trip due to a pressure spike during lube oil pump swapping, shift turnovers and briefings, and routine surveillance and special testing. The following documents were reviewed by the inspectors:

- Operations Head Instruction (OHI)-4012, "Conduct of Operations (Shift Turnover)," Revision 14, Change Sheet (CS) 1
- Plant Manager Instruction (PMI)-2011, "Procedure Use and Adherence," Revision 2
- Operating Philosophy and Practices, OPP.1, "Control Board Monitoring During Non-Emergency Operational Conditions," Revision 4
- OHI-4013, "Operators: Authorities and Responsibilities," Revision 9, CS 2
- Operations Head Procedure, 02-OHP 4021.001.002, "Reactor Startup," Revisions 18 and 20
- 02-OHP 4021.001.006, "Power Escalation," Revision 15
- 01-OHP 4021.057.006, "Operation of Main and Feedpump Condensers," Revision 8

- 02-OHP 4021.032.001AB, "DG2AB Operations," Revision 3
- 02-OHP 4021.050.001, "Synchronize the Generator to the Grid," Revision 9
- 12-EHP 6040 PER.106, "Emergency Diesel Generator Control Panel Tests," Revision 0
- Job Orders (JOs) No. R0012482 and No. R0012485, Motor Operated Valve Analysis and Test System (MOVATS) testing of valves 2-WMO-722 and 2-WMO-724
- OHP 4030 STP.021, Data Sheet 21, breaker alignment verification with an inoperable EDG

b. Observations and Findings

Overall, command and control of control room activities was good. Unnecessary personnel were minimized and the ambient noise level was low. With some exceptions, auxiliary equipment operators (AEOs), reactor operators (ROs), and supervisory senior ROs (SROs) used three-way communications, the licensee's standard. The attentiveness of the ROs to the panels during the power ascension of Unit 1 subsequent to the refueling outage and during the shutdown and restart of Unit 2 was good; however, a significant exception occurred on May 13, 1997, when an RO inadvertently closed 2WMO-736, the essential service water (ESW) inlet valve to the 2 West component cooling water (CCW) heat exchanger, while adjusting the position of an adjacent valve. The valve remained closed for the duration of the work shift, about 12 hours, and was identified by the Unit 2 SRO at the start of the next shift. The closure of the valve rendered the West train of Unit 2 CCW inoperable and resulted in an inadvertent entry into the 72-hour limiting condition for operation (LCO) for CCW. From discussions with the RO and other operations personnel, the inspectors determined that the mispositioned valve was due to personnel error and remained undetected for 12 hours because of poor attentiveness to the control room panel by the RO and supervisory personnel.

Overall, ROs responded appropriately to annunciators; however, annunciators for doors in the plant were occasionally received and attributed by the ROs to AEOs on rounds or other personnel entering on routine surveillances. However, plant personnel, other than AEOs, may have been the cause for the alarm. To provide for positive control over personnel entering plant areas that initiate alarms in the control room, a need was identified by the inspectors for better communications between personnel entering these doors and control room personnel.

While observing operators respond to control room annunciators, the inspectors noted that three control room annunciator response procedures did not accurately reflect current operating practices or design. One procedure for the containment pipe tunnel sump indicated that operators should leave the sump level control system in "auto" to help preclude high level alarms. The licensee's current practice was to leave the sump level control in manual so that operators were made aware

of the frequency of the need for sump level reduction. The second procedure was associated with the testing of the EDG using a test load bank. The annunciator alarm procedure indicated that the test bank breaker automatically tripped when the alarm annunciated. However, system engineering personnel subsequently determined that the breaker may not trip for test bank conditions that initiate the alarm. The third procedure stated that the setpoint for the rod dropped or rod bottom annunciator was 20 steps from the bottom when it was 20 steps for all rods but one which was 35 steps. All three procedures were subsequently corrected by the licensee. A similar problem with discrepancies in annunciator response procedures was noted in the recent NRC System Operational Performance Inspection (Inspection Report No. 50-315(316)/96013).

Turnovers and briefings conducted in the shift supervisor office and in the AEO turnover room (both were adjacent to the control rooms) were well conducted; however, background noise from nearby equipment was high. The licensee stated that a plant modification had recently been approved that when implemented would reduce the noise. Turnovers in the control room between the ROs and the supervisory SROs were also well conducted. A possible instance where a pre-evolution briefing was not thorough occurred on May 7 during a run of the 2AB EDG. When the RO placed the voltage regulator in manual and the voltage meter pegged high, the SRO had to direct the RO to return the regulator back to automatic. The RO should have been made aware of this contingency during the briefing.

As mentioned above and discussed in detail in Section M1.3, the 2AB EDG was declared inoperable because of problems with a voltage regulator. During the initial troubleshooting, the licensee concluded that repairs would not be completed before expiration of the 72-hour limiting condition for operation associated with Technical Specification (TS) 3.8.1.1. The licensee shutdown the reactor before the end of the 72 hours.

c. Conclusions

Overall, control room activities were well conducted. An exception was noted in the inadvertent mispositioning of a Unit 2 ESW/CCW valve by an RO at the start of a shift and the failure of the RO and supervisory SROs to identify the mispositioned valve for the remainder of the 12-hour shift. Also, notification of the control room for entry into areas with alarmed doors needed improvement as did the quality of several annunciator response procedures.

O1.2 Missed Unit 1 Surveillance of Reactor Coolant Temperature

a. Inspection Scope

On May 5, 1997, the licensee failed to determine reactor coolant system average temperature (Tavg) every 30 minutes with the low Tavg alarm inoperable, as required by TS 4.1.1.5.b. The inspectors followed up on the licensee's response to this event and reviewed the following procedures:

- Instrument and Control Head Procedure 01-IHP 4030.SMP.104, "Delta-T/Tavg Protection Set I Functional Test and Calibration," Revision 2

- 01-OHP 4030.STP.021, "Event Initiated Surveillance," Revision 8

- PMI-4031, "Event Initiated Surveillance," Revision 8

b. Observations and Findings

On May 5, 1997, surveillance procedure 01-IHP 4030.SMP.104, "Delta-T/Tavg Protection Set I Functional Test and Calibration," was being performed to calibrate the loop delta-T instruments following a Unit 1 startup and power escalation. The calibration procedure cautioned that entry into Technical Specification 4.1.1.5.b may be required as a result of the surveillance. Technical Specification 4.1.1.5.b required, in part, that Tavg be determined to be greater than 541°F at least once per 30 minutes when the reactor was critical and the low Tavg alarm was inoperable. However, during the performance of the surveillance procedure, the operators failed to determine Tavg during the first 30 minutes after the low Tavg alarm was made inoperable.

The operators reviewed the control room chart recorders and verified that Tavg had not dropped below 541°F during the event; therefore, this event had no safety significance. Additionally, operator training was conducted with all shifts to emphasize the importance of performing surveillances that require TS directed actions. These actions appeared adequate to prevent recurrence, and the inspectors had no further concerns. This licensee-identified and corrected violation of TS 4.1.1.5.b is being treated as a Non-Cited Violation (NCV 50-315/97009-01) consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

On May 5, 1997, the licensee failed to determine Tavg every 30 minutes with the low Tavg alarm inoperable. A non-cited violation of TS 4.1.1.5.b was identified.

O1.3 In-plant Observations

a. Inspection Scope

As part of the continuous 72-hour coverage of control room activities, the inspectors accompanied AEOs on routine rounds of the turbine and auxiliary buildings to observe the AEOs and to examine plant material condition. The following documents were also reviewed by the inspectors:

- 01-OHP 5030.001.001, "Operations Plant Tours [Unit 1]," Revision 10, CS 1

- 02-OHP 5030.001.001, "Operations Plant Tours [Unit 2]," Revision 9, CS 1

- 01-OHP 4030.STP.020W, "Unit One West CCW Loop Flow Path Verification," Revision 6

b. Observations and Findings

In general, AEOs were thorough, knowledgeable, and conscientious in the performance of their rounds. In the plant, AEOs checked equipment in addition to that listed on the plant tour sheets, questioned workers engaged in maintenance or testing to determine the purpose of their work, and wrote action requests for items that needed repair or evaluation. The AEOs followed radiation protection, security, and industrial safety requirements. Material condition of equipment in the auxiliary building was good. In the turbine building, the inspectors noted oil and water leaks on the Unit 1 feedwater pumps, which had been worked on during the recently completed refueling outage. The licensee stated that a plan was being developed to address the material condition of the pumps.

c. Conclusions

Overall, the performance of the AEOs was very good. Material condition in the auxiliary building was also good, while that of the Unit 1 main feedwater pumps suffered from several oil and water leaks.

O1.4 Annunciator Response Outside the Control Room

a. Inspection Scope

On May 6, 1997, the inspectors followed the licensee's response to an annunciator in the control room. Additionally, the following procedures were reviewed:

- 01-OHP 4024.104, Annunciator #104 Response: "Essential Service Water and Component Cooling," Revision 11
- 01-OHP 4024.124, Annunciator #124 Response: "Containment," Revision 3
- OPP.7, "Annunciator Response"
- PGG.001.006, "Procedure/Change Sheet Distribution," Revision 11
- OPM.003, "Operations Department Procedure Change Sheet Process," Revision 0
- Condition Report (CR) 97-1535, "Annunciator response procedures not at CAS panel"

b. Observations and Findings

In response to a Unit 1 CAS (Containment Annunciator Subpanel) Sump Pump Abnormal annunciator, the RO dispatched an AEO to the CAS panel. The AEO

went to the CAS and identified the annunciator as the Pipe Tunnel 2B Sump Abnormal. The AEO called the control room and performed the actions required by the annunciator response procedure; however, the AEO did not consult the procedure directly because no copies of the annunciator response procedure were at the CAS panel.

A CR was written, and an existing action request was completed which attached a procedure storage rack to the Unit 1 CAS panel. Additionally, the licensee verified that the required procedures were at all other local operating stations listed in PGG.001.006 Attachment 2. The inspectors noted Attachment 2 to PGG.001.006 listed the Unit 1 CAS panel as the location where 01-OHP 4024.124 would be maintained.

The failure to maintain the annunciator response procedures at the containment annunciator subpanel was contrary to procedure OHI-2030, and thus a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which requires that procedures be adhered to. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV 50-315/97009-02) consistent with Section IV of the NRC Enforcement Policy.

c. Conclusions

The annunciator response procedures for the Containment Annunciator Subpanel were not located at the panel as required by licensee procedures. A violation of minor significance was identified and treated as a Non-Cited Violation.

O1.5 The Focus of Station Operations

a. Inspection Scope

The inspectors reviewed the licensee's efforts to foster the leadership role of the operations department in day-to-day station operations. In late 1995, the licensee had identified a need to reestablish that role.

b. Observations and Findings

The efforts included the restructuring of the daily action request prioritization, plant status, and upper managers meetings to make them operations-centered, and the institution of weekly upper management/staff informal meetings and a plant operations group (the POG). Monthly meetings were held with supervisors of the five major departments that compose the POG. The focus of the POG was team-building, leadership development, and a forum to communicate and discuss standards and expectations.

c. Conclusions

Through observations at several special meetings (including those to discuss the EDG problem), at daily meetings, and in the control room, the inspectors concluded that the overall focus of station operations was on the operations department.

O1.6 Corrective Actions Program

a. Inspection Scope

A licensee quality assurance (QA) audit in early 1996 and recent NRC inspections (Inspection Reports No. 50-315(316)/96003, 50-315(316)/96012, 50-315(316)/96013) identified instances where CRs had not been written as required. The inspectors attended several CR review meetings, discussed program implementation with station personnel, and reviewed CRs and CR statistics. In addition, the following documents were reviewed:

- PMI-7030, "Corrective Action," Revision 22, CS 7
- Plant Performance Assurance Audit QA-95-14, October 17, 1995 to January 15, 1996
- Audit No. NSDRC No. 234, March 18 through May 20, 1996
- Plant Performance Assurance Audit QA-96-22, October 15 to December 30, 1996
- Memorandum from senior station management to plant staff, "Identification of Conditions, Sr. Management Expectations," October 7, 1996

b. Observations and Findings

Station management's attempt to increase the sensitivity of plant personnel to the need to write CRs has been successful. In 1995, approximately 1800 CRs were written. This increased in 1996 to approximately 2200, and increased again in the first five months of 1997 to 1500. From observations of and discussions with plant staff, the inspectors determined that plant personnel were indeed sensitive to the need to document problems in CRs. Condition Reports were written for all the significant findings of the OSTI. In addition to the increase in the number of CRs, the station issued Revision 23 of PMI-7030, intended to address other previous QA findings on timeliness of CR closeout and the adequacy of CR followup. The revision was issued near the end of the inspection and was not reviewed by the inspectors.

c. Conclusions

The licensee's efforts to increase the number of plant problems entered into the station's CR program was successful. Other enhancements made to the program were only recently implemented and could not be assessed.

O2 Operational Status of Facilities and Equipment

O2.1 Equipment Out-of-Service Control

a. Inspection Scope

The inspectors reviewed the implementation of the licensee's program (the "clearance" or "tag-out" process) for the control of out-of-service equipment. As part of this review, the inspectors discussed the clearance process with the Centralized Clearance Group, which prepared the clearances, and with operations department personnel who hung and removed clearance tags. In addition, the inspectors observed the preparation, hanging, and removal of clearance tags for work on a chilled water pump and glycol chillers.

On May 8, 1997, during this review, a fuse blew on the diesel generator inverter while restoring a clearance on the 2AB EDG voltage regulator. The inspectors also followed up on the licensee's response to this event.

The following documents were reviewed during the inspection activities:

- PMI-2110, "Clearance Permit System," Revision 23
- 02-OHP 4021.032.008, "Aligning DG2AB Subsystems for Standby Operation," Revision 4
- JO C40921, "Troubleshoot 2AB EDG voltage regulator"
- JO R45379, "Unit 2 AB EDG inverter preventive maintenance"
- CR 97-1420, "No procedural guidance for removal and restoration of the 2AB EDG inverter"
- CR 97-1433, "Blown fuse during 2AB EDG inverter restoration"
- CR 97-1452, "Partial clearance addition determined as root cause for blown fuse on 2AB EDG inverter"

b. Observations and Findings

For the clearance activities observed by the inspectors, no problems were identified. Preparers of clearances retrieved computer copies of previous tag-outs and verified boundaries on flow drawings and electrical prints. Tags and hard copies of

clearance sheets were signed off by the requestor and sent to the shift supervisor's office for review by an SRO. The AEOs hanging the clearances compared information on the tag with the clearance sheet and the in-plant label before positioning the component and hanging the tag. The tags were hung in the proper sequence. The inspectors also noted that the AEOs followed station requirements for using leather gloves, eye protection, and hard hats when positioning breakers. A second verifier (another AEO) performed independent verification of the hanging and removal of tags.

Regarding the inverter clearance issue, the inspectors noted the following. On May 7, 1997, a partial addition to clearance 2971776 was hung on the 2AB EDG voltage regulator for troubleshooting under JO C40921. Breaker 2-TDAB-2 was included in the clearance addition; however, the requestor, reviewer, and approver of the partial clearance failed to identify this breaker as the supply to the Unit 2AB EDG inverter. Also, procedure 02-OHP 4021.032.008 was not referenced in the tagout as the procedure that contained the appropriate steps to properly de-energize the inverter. The partial clearance was hung, opening breaker 2-TDAB-2 without reference to the procedure. The instruction to restore clearance 2971776 (that is, remove the tags and restore the equipment) required the use of the procedure to close 2-TDAB-2; however, after the clearance was removed and during inverter restoration, a fuse blew on the inverter. The fuse was replaced, and the licensee investigated the event.

The licensee's investigation determined that when the partial clearance tags were hung, the 2AB EDG inverter was not properly de-energized; however, the restoration procedure assumed otherwise. Therefore, even though the procedure was used to return the inverter to service, the initial assumptions of the procedure were not met.

After the event, the licensee directed that all further planned clearances on the 2AB EDG be reviewed for potential inadvertent de-energizations of the 2AB EDG inverter. In addition, a label was placed on all four EDG inverter supply breakers (one breaker per one inverter per each EDG) to remind operators to use the procedure prior to operating the breaker.

The failure to use the proper procedure for de-energizing the 2AB EDG inverter is considered by the inspectors to be another example of a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" (50-316/97009-03). The corrective actions described above appeared to be adequate to prevent recurrence.

c. <u>Conclusions</u>

Overall, the observed method of preparing clearances, hanging and removing tags, and entering data was in accordance with the licensee's clearance procedure. One example of a failure to follow procedure violation was identified for improperly de-energizing the 2AB EDG inverter.

O2.2 Operator Workarounds

a. Inspection Scope

The inspectors assessed the licensee's program for the control of operator workarounds. The assessment included a review of the workaround and "watch" lists and the licensee's determination of the aggregate impact of workarounds. The following procedure was reviewed as part of the assessment:

- PMI-4016, "Oversight and Control of Operator Workarounds," Revision 0

b. Observations and Findings

Operator workarounds were controlled in accordance with PMI-4016. Section 2.2 of the procedure defined the watch list as "a list of deficiencies which do not involve significant compensatory actions but are periodically reviewed for their aggregate impact." The PMI stated that the watch list should include "Institutionalized Workarounds - that is, design deficiencies for which compensatory actions have been incorporated into plant procedures."

The inspectors noted that institutionalized workarounds were removed from the watch list at workaround board meetings after a vote by the members present. This practice was consistent with the procedure.

c. Conclusions

Operator workarounds were controlled in accordance with station procedures; however, the inspectors noted that practice of removing institutionalized workarounds from the watch list potentially limited the ability of the licensee to assess the aggregate impact of the workarounds. This item was discussed at the inspection exit.

O3 Operations Procedures and Documentation

O3.1 Engineered Safety Feature Walkdowns

a. Inspection Scope

The inspectors walked down engineered safety features equipment of the ESW, CCW, and auxiliary feedwater (AFW) systems using the licensee's system lineup procedures and as-built prints to determine if plant conditions conformed to the procedures and prints.

b. Observations and Findings

Valve Description on Labels and Drawings and in Procedures

From the walkdowns of the three systems, the inspectors identified:

- No labeling on flow drawings (piping and instrumentation diagrams) for various valves including root valves and air controlled valves.

- Valve 1-CCW-200W on Unit 1 had no chain operator; however, valve 2-CCW-200W on Unit 2 had a chain operator. Many other valves in the same general area had a chain operator and were just as inaccessible as 1-CCW-200W. Plant isometric drawing 1-CCW-523L1.7, Revision 7, indicated that the valve should have a chain operator. The licensee wrote CR 97-1467 to evaluate the problem.

- The description given for valves in the procedure or procedure data sheet did not match the description on the valve labels. It was noted that the valve label did match the description contained in the Facility Data Base. The following were examples of discrepancies:

    - The description of 2-ESW-244 in the procedure was "2-WMO-744 & 2-ESW-243 Telltale Drain Valve." The tag label was "Emergency ESW Supply to West MDAFP Valves 2-WMO-744 & 2-ESW-243 Telltale Drain Valve."

    - The description of 1-FPI-253-V1 in the procedure was "Turbine Driven Auxiliary Feedwater Pump PP-3E Discharge Pressure Indicator Transmitter." The tag label was "TDAFP 1-PP-4 Discharge Pressure Indic Transmitter 1-FPI-253 and Test Point 1-FPX-257 Root Valve."

    - The description of 1-CCW-187W in the procedure was "West Centrifugal Charging Pump Oil Cooler Inlet." The tag label was "CCW to West CCP 1-PP-50W Gear and Bearing Oil Cooler Inlet Valve."

Other examples of label deficiencies for all three systems were communicated to the licensee at the inspection exit. These findings represent additional examples of a cited violation in Inspection Report 50-315(316)/97002 and a non-cited violation in Inspection Report 50-315(316)/97003. However, the inspectors evaluated each item and determined them to have minor safety significance. Also, the licensee was in the process of developing corrective actions to address these type of issues. Consequently, in accordance with Section IV of the NRC Enforcement Policy, these examples are considered a Non-Cited Violation (NCV 50-315(316)/97009-04). The licensee made the following commitments to correct the problems:

Commitment I - The licensee completed an Operations Department Self Assessment of Operations Department Procedures in late 1996. An item identified in that self-assessment to which the licensee committed to the NRC during the OSTI was the

implementation of an Operations Procedure Improvement Program. Projected completion date for the Normal Operating Procedure upgrade portion of that program was December 31, 1998.

Commitment II - The licensee committed to the NRC during the OSTI to develop the Mechanical Design Group "Flow Diagram Standard Practice Guideline." The projected completion date was August 15, 1997. This guideline will contain information to ensure engineers are consistently labelling components on the flow diagrams.

Sealed Valves

The inspectors identified during the CCW system walkdown that valves 1-CCW-200W and 1-CCW-202W were both sealed in the open position, although the surveillance procedure 01-OHP-4030.STP.020W, 01-OHP 4030.STP.035, "Controlled Valve Position Logging" Revision 18, did not designate them as sealed. In addition, lineup sheet No. 4 from the same procedure did not designate the valves as sealed. Review of plant records, including other valve lineup sheets where the valves may be listed, did not reveal what caused the valves to be sealed. The licensee subsequently removed the seals and wrote CR 97-1512 to determine the cause.

The sealed valve discrepancies are further examples of the procedural inadequacies described in Inspection Reports Nos. 50-315(316)/97002 and 50-315(316)/97003. The problems themselves were minor and consequently, in accordance with Section IV the NRC Enforcement Policy, are considered a Non-Cited Violation (NCV 50-315(316)/97009-05). In February 1997, the licensee completed an operations department self-assessment of the sealed valve program. Three items were identified in that self-assessment to which the licensee made the following commitment to the NRC during the OSTI:

Commitment III - Revise 01-OHP 4030.STP.053A, "E.C.C.S. Valve Operability Test Train A," Revision 9, and 01-OHP 4030.STP.053B, "E.C.C.S. Valve Operability Test Train B," Revision 9, for Unit 1 and 02-OHP 4030.STP.053A, "E.C.C.S. Valve Operability Test Train A," Revision 11, and 02-OHP 4030.STP.053B, "E.C.C.S. Valve Operability Test Train B," Revision 10, for Unit 2 to incorporate both trains of emergency core cooling system (ECCS) valves manipulations into one procedure and have only one monthly valve lineup for both Units. Projected completion date was July 31, 1997. Also, the licensee will develop a program document for sealed valves to document why the valves are controlled. Projected completion date was December 31, 1997. Finally, the licensee will eliminate TS references which no longer apply in 01-OHP 4030.STP.035, "Controlled Valve Position Logging," Revision 18, for Unit 1, and 02-OHP 4030.STP.035, "Controlled Valve Position Logging," Revision 14, for Unit 2, and add Updated Final Safety Analysis Report (UFSAR) references which do apply. Projected completion date was July 31, 1997.

Mispositioned Valves

1-ESW-103E, East ESW Pump Discharge Strainer 1-OME-34E West Basket Drain Valve, required position was CLOSED. The licensee investigated the problem and found the valve was OPEN but capped such that no water could leak out. The licensee wrote CR 97-1475 to determine the root cause.

2-WFI-732-V2, East ESW Supply Header to East CCW Hx Inlet Flow Indication Transmitter 2-WFI-732 Low Press Root Valve, required position was OPEN, but the valve appeared closed. The licensee investigated the problem and found the valve was opened slightly over one turn. The fully open position was slightly over two turns. The licensee wrote CR 97-1474 to determine the root cause.

c. Conclusions

Discrepancies were identified involving incorrect equipment nomenclature used in procedures, the mis-labeling of flow diagrams, and unnecessarily sealed valves. The licensee made three commitments to rectify the discrepancies. Two non-cited, minor violations were identified.

O3.2 Procedural Adherence

a. Inspection Scope

Problems with procedure adherence have been identified during recent NRC inspections (Inspection Reports No. 50-315(316)/96006; 50-315(316)/96011; 50-315(316)/96013; 50-315(316)/97002; and 50-315(316)/97004) and by the licensees, as documented in CR 97-1527 that described ineffective corrective actions for 15 earlier CRs on procedure adherence. During the OSTI, the inspectors observed licensee staff adherence to numerous procedures and discussed with licensee management actions planned to improve procedure adherence. The following documents were also reviewed by the inspectors:

- American Electric Power Nuclear Organization Policy Regarding Safe Operation and Adherence to Procedures, License Conditions, and Technical Specifications, 661000-POL-4000-02, Revision 0
- Procedure Adherence Policy Cook Nuclear Plant, 227000-POL-4000-02, Revision 1
- PMI-2010, "Instructions, Procedures, and Associated Indexes Policy," Revision 23
- PMI-2011, "Procedure Use and Adherence," Revision 2
- Maintenance Department Procedure Writers and Users Guide

- Operations Standing Order OSO.124 "Procedure Use and Adherence," Revision 0

b. Observations and Findings

Numerous instances of procedure use were observed by the OSTI inspectors. Problems with procedure adherence were identified during observation of activities associated with temporary modifications (Section E2.1) and deenergization of a Unit 2 AB EDG inverter (Section 02.1). In addition, the licensee identified an adherence problem with the work package for the EDG voltage regulator (Section M1.3).

The inspectors noted that the station planned a site-wide "procedure use and adherence timeout," for May 27, during which supervisors would meet with employees for about an hour to discuss station expectations on procedure use and adherence, review recent pertinent examples where procedures were not properly used or adhered to, and to review upcoming changes to PMI-2011, on procedure use and adherence. Included in the procedure revision was a change to the industry standard classification of procedures of continuous use, reference use, and information use.

c. Conclusions

The licensee continued to have problems with procedure adherence, although some improvement was evident. The planned "time-out" appeared to be good effort by the licensee to gain further improvements.

O4 Operator Knowledge and Performance

O4.1 Non-Essential Service Water Pump Breaker Would Not Trip

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the failure of the Unit 1 south non-essential service water (NESW) pump to trip on April 30, 1997, when the control switch was taken to the trip position. The following associated documents were reviewed:

- CR 97-1383, "South NESW Pump Would Not Trip"
- CR 97-1409, "While Reviewing AR's for PMI-4016, 'Oversight and Control of Operator Workarounds, Revision 0'"
- Calculation PS-EDGL-001, "EDG 1AB Steady-State Loading and Voltage Drop," Revision 0
- UFSAR, Section 8.4, "Emergency Power System"

b. Observations and Findings

Condition Report 97-1383 documented this issue and stated that the pump tripped after the fifth attempt to trip the breaker. The inspectors noted that CR 97-1383 left the pump in an operable status and did not require a prompt operability determination to be performed. Because of previous similar problems, the licensee suspected the control switch was malfunctioning.. An action request was written to investigate the failure.

On May 5, 1997, a shift technical advisor (STA) was reviewing the action request and determined that CR 97-1383 did not consider that the Unit 1 south NESW pump, although not safety-related, needed to trip on a load shed signal to the associated EDG. Another CR (CR 97-1409) was subsequently written to capture this issue and require that the pump breaker be racked out until it could be verified that the problem did not affect the load shed function. The condition report (97-1409) further stated that the pump had been in the standby mode since the problem was identified; thus, there was no challenge to the train B load shed function. The licensee subsequently declared the pump out-of-service, racked its breaker out, and began troubleshooting.

The inspectors questioned the licensee whether the EDG would have been overloaded upon a hypothetical load shed signal and a failure of the NESW pump to trip. The licensee stated that if the NESW pump had not tripped, the EDG would have exceeded its steady-state rated load of 3500 kilowatts, but would have been within its two-hour overload rating. Upon further study, the licensee concluded that the additional loading would not have prevented the EDG from supplying its loads under postulated emergency conditions.

The licensee stated that the troubleshooting showed the breaker was functioning properly, but the control switch was suspect. Based on this, the licensee concluded that the breaker would still have tripped on a load shed signal.

c. Conclusions

The licensee's review of CR-1383, which included the shift supervisor, an STA, and the CR review group, appeared to assume that the problem was a repeat occurrence of a malfunctioning switch and missed the need to consider the effect of an untripped NESW pump breaker on EDG loading if, in fact, the problem was not with the switch. Fortuitously, another STA identified the need during an unrelated review of the associated action request. Because the breaker was subsequently found to be operable, the safety significance of the poor initial review of CR-1383 was low.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillances

a. Inspection Scope

On May 12, 1997, the inspectors observed implementation of procedure 02-OHP-4030-STP-022CS, "ESW System Cold Shutdown Test," Revision 2, a flush of U-2 ESW emergency water supply lines and a full-stroke test of three ESW valves.

b. Observations and Findings

The two AEOs performed the flush and test in accordance with the procedure and properly verified final valve positioning. No major problems were identified by the AEOs or the inspectors. A work request was written for a loose packing nut on one of the system drain valves and excess paint was cleaned from the bolt threads of another valve on which the AEOs had to loosen a valve position lock bolt/nut prior to repositioning the valve.

c. Conclusions

The procedure was properly implemented and appeared to satisfy the intended purpose of flushing the emergency supply lines and full-stroke testing the three ESW valves, per 10 CFR 50.55a requirements.

M1.2 Unit 2 AB Emergency Diesel Generator Planned Maintenance

a. Inspection Scope

On May 6, 1997, the licensee voluntarily entered the action statement of TS 3.8.1.1 in order to perform 33 hours of planned maintenance on the 2AB EDG. The action statement allowed the diesel to be inoperable for 72 hours, after which the reactor would have to be shut down.

On May 8, 1997, after encountering problems during 2AB EDG post-maintenance testing (PMT), the licensee shut down Unit 2 after concluding that the 2AB EDG would not be returned to service before the 72-hour LCO expired. The inspectors observed portions of the maintenance and troubleshooting activities. Details of EDG inverter maintenance and voltage regulator troubleshooting are discussed in Sections O2.1 and M1.3, respectively. The following documents were reviewed by the inspectors:

- OHP 4030 STP.021, "Event Initiated Surveillance," Revision 8
- JO C37227, "Replace O-ring #5 rear cylinder"

- JO R12482, "ISI stroke time on 2-WMO-722"
- JO R12485, "ISI stroke time on 2-WMO-724"
- JO R45418, "AB D/G South aftercooler auto vent"
- JO R45419, "AB D/G North aftercooler auto vent"
- JO R62606, "Blower crankcase breather"
- CR 97-1442, "2AB EDG scheduling time line did not accurately reflect post maintenance testing"

b. Observations and Findings

The inspectors observed the job brief for the clearance on the 2AB EDG at the start of the scheduled maintenance. A second, impromptu briefing was held between the operating shift and the diesel generator system engineer to discuss operations responsibilities and communications during diesel testing. Both briefings were thorough and the operating shift questions concerning the planned activities were answered.

The clearance for the 2AB EDG was delayed for a short time while some pre-staged scaffolding was moved to allow access to a valve 2-ESW-167AB, which required a clearance tag. The scaffolding did not block operation of the valve; however, it did make it difficult for the AEO to place the required tag. The inspectors followed AEOs hanging the clearance tags and noted no deficiencies.

The inspectors also observed several of the planned maintenance activities and found the work was of generally good quality with the work packages in active use at the job sites. However, some problems in planning and scheduling slowed down the job while in the 72-hour LCO. Specifically, the licensee identified that:

- The clearance for MOVATS testing of 2-WMO-722 and 2-WMO-724 failed to isolate ESW. Isolating ESW was not stated in the initial clearance request to operations although it was required.
- There was no procedure for removing the 2AB EDG inverter from service similar to the procedure used for the Unit 1 EDG inverters. Inverter maintenance was delayed until a procedure was written. The inverter is discussed in more detail in Section O2.1.
- The scheduling time line for the diesel maintenance did not accurately reflect the amount of PMT. The shift supervisor commented that this burdened the control room crew with coordinating the testing.

c. Conclusions

The planned maintenance work on the 2AB EDG was generally of good quality. The licensee identified several planning problems involving PMT scheduling and clearance requests.

M1.3 Unit 2 AB Emergency Diesel Generator Voltage Regulator

a. Inspection Scope

The inspectors followed the licensee's troubleshooting of the faulty 2AB EDG voltage regulator. The documents listed below were also reviewed by the inspectors:

- 02-OHP 4021.032.001AB, "DG2AB Operation," Revision 4
- 12-EHP 6040 PER.106, "Emergency Diesel Generator Control Panel Tests," Revision 0
- PMI-3130, "Plant Stores Material, Storage and Handling Control," Revision 5
- Plant Manager Procedure, 12-PMP-3130 SMC.001, "Control and Tracking of Safety Related Materials, Parts, and Components," Revision 1
- 12-OAP 3130 SMC.001, "Stores Nuclear Safety Related Material Identification and Control," Revision 7
- 12-OAP-3130 SMC.005, "Stores Material Issuing Control," Revision 5
- 12-MMP-3130 NESS.007, "Stores Material Receiving Control," Revision 0
- VTD-GENE-1199, "General Electric Instructions for Voltage Regulator for Use with Synchronous Generators," [Publication No. GEK-14995B]
- American National Standards Institute (ANSI) N45.2.2-1976, "Packaging, Shipping, Receiving, Storage and Handling of Items for Nuclear Power Plants (During the Construction Phase)"
- ANSI N45.2.13-1976, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants"
- JO R45360, "Unit 2 AB EDG voltage-regulator clean circuit boards preventive maintenance"
- JO C40921, "Unit 2 AB EDG troubleshooting"
- CR 97-1438, "2AB EDG manual voltage regulator failed to control voltage following maintenance"

- CR 97-1450, "2AB EDG manual voltage regulator failed to control voltage on third attempt to functionally test the regulator"
- CR 97-1484, "Unit 2 shut down due to technical specification 3.8.1.1"

b. Observations and Findings

A preventive maintenance inspection and cleaning of the 2AB EDG voltage regulator (JO R45360) was included in the planned LCO work package. This involved removing the automatic regulator card, the manual regulator card, and the fault current card from a chassis; inspecting and cleaning them; and reinstalling the cards in the chassis. On May 6, 1997, a slow start test of the EDG was performed following maintenance. The test failed when the manual voltage regulator failed to control output voltage, over-ranging the meter at 150 volts; operators then stopped the engine.

The licensee's initial investigation determined that the manual voltage regulator card had not been properly tightened when reinstalled, resulting in some arcing when the voltage regulator was energized. Several components on the manual regulator card were damaged from the high voltage, and the manual regulator and fault current cards were subsequently replaced with cards from a spare voltage regulator. The licensee also measured the generator exciter resistance to verify that the high voltage did not damage the insulation. None was found. Another slow start test was performed and the manual voltage regulator again failed to properly control output voltage, with an over-ranging of the meter.

The licensee's investigation of the second failure determined that two silicon controlled rectifiers (SCRs), integral to the voltage regulator chassis, were damaged. The in-service 2AB EDG voltage regulator was then replaced with the spare voltage regulator. Another test of the 2AB EDG was conducted and again the voltage regulator malfunctioned, this time failing to automatically regulate voltage properly. The engine was shut down, and the voltage regulator was removed for further testing. At this point, the licensee determined that the 2AB EDG would not be returned to service before the 72-hour LCO expired and decided to shut down Unit 2 in order to comply with TS 3.8.1.1 (Section O1.1).

Because the spare voltage regulator had passed bench testing prior to being installed, the licensee obtained a voltage regulator expert to assist with the troubleshooting. The expert performed more extensive bench testing, but this additional testing did not identify any anomalies. The spare voltage regulator's automatic regulator card was replaced with the card from the original voltage regulator, and the spare voltage regulator was thoroughly cleaned and reinstalled.

The 2AB EDG was again run with the spare voltage regulator (on May 11), using the spare chassis, the spare manual regulator card, the spare fault current card, and the original automatic regulator card. This time, the automatic voltage regulator functioned properly; however, the manual voltage regulator did not properly control voltage from the remote (control room) potentiometer. The local (diesel room)

manual voltage adjust potentiometer did control voltage. The licensee determined that the problem was either in the control room potentiometer or the wiring between the control room and the diesel room.

The licensee had determined that the manual voltage regulator was not a part of the safety-related portion of the EDG; therefore, manual voltage control was not required for EDG operability. Further troubleshooting and repair were postponed until the next Unit 2 refueling outage, planned for fall 1997. A temporary modification (TM) which disabled both the local and remote 2AB EDG manual voltage control functions was installed, and the 2AB EDG was declared operable after successfully completing a 1-hour operability run. The inspectors reviewed the TM and safety screening and had no concerns.

The licensee's investigation of the initial failure of the voltage regulator determined that workers had not followed JO R45360 requirements to "ensure all mounting hardware and connections were tight" after reinstalling the manual regulator card after cleaning. In addition, the licensee determined that supervisory oversight of the job was poor. The individuals involved were counselled, and the problems and a restatement of expectations were communicated to all station personnel. The failure to tighten the circuit board as required by the instructions in the JO was a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for failure to follow procedure. This licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV 50-316/97009-06) consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The workers reinstalling the 2AB EDG manual voltage regulator card after a routine cleaning failed to properly tighten the connections, leading to a failure of the voltage regulator during testing. A non-cited violation was identified for a failure to follow a procedure.

The initial troubleshooting into the 2AB EDG voltage regulator failure was weak and did not identify two failed SCRs.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Minor Maintenance Program

a. Inspection Scope

The inspectors reviewed the licensee's control of minor maintenance, much of which was done in the so-called "Work It Now" or WIN program, to determine the extent of operations department cognizance and control of equipment repaired outside the traditional work order process. As part of this review, the inspectors referred to procedure PMI 2291, "Work Control Process," Revision 4.

b. Observations and Findings

The licensee's WIN program was only recently instituted (in January 1997) and has had little opportunity to impact the number of items around the plant that needed repair. The WIN team was headed by an experienced maintenance department supervisor and an operations department supervisor, who was also an SRO. The program was developed after a review was conducted of minor maintenance programs at about 15 other plants. Currently, about 6 minor maintenance items (termed administrative tasks) were being completed per day with an initial review of the items being conducted by the operations department Task Master (an SRO) and the WIN team SRO supervisor to insure safety-related equipment was not impacted. Also, the shift supervisor (the station's senior SRO) was also notified of which items were to be worked, providing an additional opportunity for precluding inadvertent impact on safety-related equipment.

In addition, some plant maintenance work that was not handled through the work control or WIN programs was contract work done under the aegis of the buildings and grounds group in the maintenance department. This group was also the station's material condition group. In response to a problem at another nuclear plant (Inspection Report No. 50-373(374)/96009), where a sealant material was used--as a minor maintenance activity--to control groundwater inleakage, but was inadvertently injected into a safety-related service water system, the licensee took appropriate actions to prevent a similar problem at D. C. Cook. These actions included stopping ongoing sealant injection work at the station, generating a CR to ensure that the problem at the other plant was formally assessed for applicability to D.C. Cook, and providing training to appropriate station personnel on the problem. The licensee verified that existing administrative controls were adequate to prevent a similar problem at D. C. Cook, including a pre-job review by the engineering staff of planned sealant injection work to assess the impact on safety-related equipment and an ongoing comparison of the amount of the sealant used with the amount planned.

c. Conclusions

The licensee's minor maintenance program has not been in existence long enough to significantly affect the number of items needing repair in the plant. However, appropriate controls were in-place to ensure the operations or the engineering department reviewed planned minor maintenance activities for potential impact on safety-related equipment.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Temporary Modifications

a. Inspection Scope

The inspectors assessed the licensee's program for the control of temporary modifications (TMs). The assessment included a review of the TM log kept in each control room and of the effectiveness of controls for limiting the duration of TMs. The following procedures and TMs packages were reviewed:

- PMP 5040.MOD.001, "Temporary Modifications," Revision 7
- 12-THP-6020.ENV.106, "Bio-Monitoring Equipment Installation Control," Revision 1
- TM 12-96-07, "Temporary Spent Fuel Pool Demineralizer"
- TM 12-96-20, "Blank for Cold Chem Lab Air Conditioning"
- TM 1-96-13, "Delay Time for Glycol Annunciator Circuit"
- TM 1-95-1, "Removal of Selected Core Exit Thermocouple Indication"

b. Observations and Findings

In PMP 5040.MOD.001, an administrative time limit of six months from the date of approval was set for TMs, with provision for 6-month extensions. On May 10, 1997, the inspectors found 7 TMs, out of a total of 35, which were past the assigned expiration date with no extension past that date on file. Of these seven, TM 1-95-1, for the removal of selected core exit thermocouple indication from the control room, involved safety-related equipment. It had been approved on January 18, 1995, and had been extended several times to August 27, 1996. The failure from August 27, 1996, to May 10, 1997, to follow PMP 5040.MOD.001 as it applied to TM 1-95-1 was a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, and be accomplished in accordance with those instructions, procedures, and drawings (VIO 50-315(316)/97009-07(DRP)).

The licensee indicated that station upper management had not granted due date extensions for these seven TMs to constrain the responsible department to commit to a date for either permanent installation of a design change or for removal of the TM. In addition, the licensee indicated that there was a backlog in completing the

design packages required to resolve TMs that were past the expiration date. In their intent to elicit action from the department, upper management inadvertently caused PMP 5040.MOD.001 to be violated.

After discussions with the inspectors, the design engineering manager and plant manager took action to eliminate the noncompliance with PMP 5040.MOD.001. Design Engineering established a firm date for carrying out the permanent installation of the design change necessary to allow close out six of the expired TMs. After the procedure was changed, the plant manager granted an extension of the due date to match the implementation date for the design change. The resolution plan was completed May 23, 1997. The seventh expired TM, on the Cold Lab air-conditioning system, was not extended; it was removed.

In addition the problem with due dates, the inspectors noted that a "proceduralized modification," 12 THP 6020.ENV.106, "Bio-Monitoring Equipment Installation Control," Revision 1, had been used since at least 1993 to monitor the effectiveness of anti-biological fouling treatment of the service water systems. The monitoring equipment was installed and used routinely to coincide with the growth cycle of the zebra mussel, roughly April through December of each year. The monitoring equipment was removed after final monitoring samples were drawn each December, to avoid the need to lay up the equipment for the months it would not be in use.

Step 4.9 of PMP 5040.MOD.001 defined "proceduralized modification" as "Any modification to plant equipment/systems which is temporarily installed via an approved plant procedure and is to be left unattended for more than one shift." Section 5.1.2 stated that "Temporary Modifications should be used for those situations which are truly temporary in nature."

Use of the monitoring equipment might be a continuing need, based on zebra mussel infestation of the Great Lakes, rather than a situation that is truly temporary in nature. The issue of when does a reoccurring TM become a permanent change will be tracked as Inspection Followup Item (IFI 50-315(316)/97009-08(DRP)) pending a review by the Office of Nuclear Reactor Regulation.

c. Conclusions

The licensee's program for the control of TMs established requirements to prevent the use of TMs as a tool for bypassing the normal design change process. A high backlog of design change work contributed to some TMs exceeding the assigned expiration date. Additionally, repetitive use of Proceduralized Modifications may be bypassing the design change process.

E7 Quality Assurance in Engineering Activities

E7.1 Installation of a Vent Line in the Safety Injection System

a. Inspection Scope

The inspectors reviewed minor modification (MM) 12-MM-590 which installed a permanent 1" vent pipe from the common safety injection (SI) pump suction header to a pre-existing drain in both Units. This review included an in-plant walkdown of the modification and a review of the following documents:

- Minor Modification 12-MM-590, Install 1" Vent Line with Globe"
- Safety Review of 12-MM-590, "Add a Vent Line to the Safety Injection (SI) Pump Suction Header," Revision 0
- AEP Nuclear Organization Policy and Procedure Manual, 227400-STG-5400-08, "Design Changes (RFCs, MMs, PMs)," Revision 0
- UFSAR, Section 2.9.3, "Seismic Design Criteria"
- Calculation DC-D-1-SI-F101, Unit 1, "Stress Analysis and Load Generation for System 1-SI-F101, Per 12-MM-590," Revision 1
- Calculation DC-D-2-SI-F101, Unit 2, "Stress Analysis and Load Generation for System 2-SI-F101, Per 12-MM-590," Revision 1
- Engineering Specification ES-PIPE-1013-QCN, "Pipe Material Specification," Revision 0
- USA Standard (USAS) B31.10-1967, "Power Piping"
- AEP Nuclear Organization Policy and Procedure Manual, 227200-STG-5400-02, "Calculations," Revision 1

b. Observations and Findings

The inspectors reviewed calculation DC-D-1-SI-F101 for modification 12-MM-590. The purpose of this calculation was to analyze the stress and load generation for the proposed modification for Unit 1. On May 7, 1997, the following observations were made:

- The modification safety review incorrectly stated that the design pressure was 30 pounds per inch-gauge (psig) and the design temperature was 100 degrees Fahrenheit (°F). The correct design pressure of 220 psig and the correct design temperature of 200°F were used in the calculation.

- The reaction force and moment due to excitation in the z-direction for span "A-H1" was left blank. The licensee stated that this was an oversight and filled in the correct values for these reactions. The calculational results were unchanged.

- The wrong moment arm was used in the determination of the reaction forces due to excitations in the x-direction for span "H1, B, V2, V3, C, H2." The moment arm used in the calculation resulted in a more conservative value than if the correct moment arm was used.

The inspectors reviewed the Policy and Procedures Manual for calculational design verification and noted that the above observations should have been discovered in the design verification process. The design verification checklist attached to the calculation showed that the inputs were correctly selected, incorporated, and documented in the calculation, contrary to the observations noted above. Failure to perform an adequate design verification of calculation DC-D-1-SI-F101 was an example of a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which required, in part, that measures be established to assure that applicable design basis were correctly translated into specifications, drawings, procedures, and instructions, and that those measures provide for verifying or checking the adequacy of the design (VIO 50-315(316)/97009-09a(DRS)).

c. Conclusions

Incorrect design input was used in the minor modification to the SI system, but the results of the calculation were valid and conservative. An example of a violation for inadequate design verification was identified.

E7.2 Auxiliary Feedwater Flow Retention Circuit Design Change

a. Inspection Scope

The inspectors reviewed the AFW Retention Circuit design change package (12-DCP-0817). The design change added a nominal 3.5-second time delay to the AFW flow retention circuits to prevent spurious actuation. The following documents were reviewed:

- 12-DCP-0817, "Revise Auxiliary Feedwater Flow Retention Circuit," Revision 0

- UFSAR, Section 10.5.2, "Auxiliary Feedwater System," July 1996

- CR 96-0754, "2-FMO-222 Did Not Throttle Back To Flow Retention Position"

- American Electric Power (AEP) Nuclear Organization Policy and Procedure Manual, 227400-STG-5400-03, "Design Change Package," Revision 1, CS 1

- AEP Nuclear Organization Policy and Procedure Manual, 227700-STG-5400-01, "Safety Reviews," Revision 2, CS 1

- System Description 12-AUXFD-100, "Auxiliary Feedwater System," Revision 0

- Design Basis Document DB-12-AFWS, "Auxiliary Feedwater System," Revision 0

- Engineering Control Procedure (ECP) 1-2-C1-01, "Condensate Storage Tank Level," Revision 13

- Safety Review of Setpoint Values for the Time Delay Pickup Relays in the AFWS Flow Retention Circuits, January 15, 1997

- CR 94-1252, "Turbine Driven Auxiliary Feedwater Pump Discharge Flow Alarm"

- Plant Nuclear Safety Review Committee (PNSRC) Meeting Minutes #3056, February 27, 1997

- PNSRC Meeting Minutes #3055, February 20, 1997

- PNSRC Meeting Minutes #3051, January 30, 1997

- PNSRC Meeting Minutes #3025, November 14, 1996

- PMP 6065.ISP.001, "Plant Instrument Setpoint Control Program," Revision 0

b. Observations and Findings

The purpose of 12-DCP-0817 was to add a time delay to the AFW flow retention circuits to prevent spurious actuation due to momentary outlet pressure spikes. CR 96-0754 indicated that spurious activation of the Unit 2 AFW flow retention circuit occurred following automatic initiation of the AFW system on May 8, 1996. The inspectors noted that the design intent of the AFW flow retention circuit was to throttle AFW flow to protect the AFW pumps from runout in the event of a high flow condition.

Attachment 16 of 12-DCP-0817 stated that the time delay setpoint was chosen to be no greater than 5 seconds since this delay would not adversely affect the AFW pumps. A time delay nominal value of 3.5 seconds was chosen because it was a value that should be easy to remember by the operators. To this, a repeatability value of ±10 percent was used to yield a setpoint range of 3.15 seconds to 3.85 seconds. The basis for the lower value was to allow sufficient time for the pump start transients to settle out. The basis for the upper value was to maintain a 1-second margin from 5 seconds for pump protection.

The inspectors verified that there was adequate net positive suction head available to the motor-driven (MD) and turbine-driven (TD) AFW pumps during the time delay duration provided that the TS minimum condensate storage tank volume was maintained. Also, the inspectors noted that the MDAFW pump would not trip on overcurrent if the pump was operating at runout flow for the time delay duration.

The inspectors reviewed the Safety Review Memorandum (SRM) attached to the design change and noted that the AFW flow retention system performed an accident mitigation function in the feedline break accident and the steamline break accident. The licensee concluded that the effect of installing a 4-second time delay in the flow retention system for the feedline break accident was bounded by the conservative assumptions used in the current Unit 1 and Unit 2 analyses. These analyses assumed a 10- minute actuation delay of the AFW system. The licensee also concluded that an increased AFW flow rate of limited duration (4 seconds) would not have a significant effect on containment peak temperature following the worst case steamline break accident. Therefore, the current steamline break analyses remained valid for the design change.

On May 13, 1997, the inspectors noted in the SRM for the steamline break evaluation that the TDAFW and MDAFW pumps started within approximately 30 seconds after the start signal. The inspectors questioned this value and the licensee subsequently stated that the MDAFW pumps started within 3.17 seconds and not the 30 seconds used in the original SRM. The licensee revised the SRM and concluded that although the MDAFW pump start times used in the original SRM were incorrect, the new values did not invalidate the conclusions of the original SRM. The inspectors reviewed the revised SRM and agreed with the licensee's conclusion.

The inspectors reviewed PNSRC meeting minutes #3025, #3051, #3055, #3056 and noted that design change package 12-DCP-0817 was approved in meeting minutes #3056. The licensee informed the inspectors that the SRM attached to the DCP was also approved in these meeting minutes.

Failure to use the correct MDAFW pump start time in the SRM for design change package 12-DCP-0817 was an example of a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which required, in part, that measures be established to assure that applicable design basis were correctly translated into specifications, drawings, procedures, and instructions, and that those measures provide for verifying or checking the adequacy of design (VIO 50-315(316)/97009-09b(DRS)).

c. <u>Conclusions</u>

A nonconservative value for the AFW pump start time was used in a safety review of a modification; however, this did not invalidate the determination that no unreviewed safety question existed. The inspectors concluded that the flow retention circuit design change was bounded by current plant safety analyses

assumptions and would not have any adverse impact on pump net positive suction head or motor overcurrent. An example of a violation for inadequate design verification was identified.

E7.3 Replacement of EDG Air Start System Safety Valves

a. Inspection Scope

The inspectors reviewed Minor Modification 12-MM-337, which replaced the EDG air start system Lunkenheimer safety valves with Consolidated Dresser safety valves. The review included the following documents:

- Minor Modification 12-MM-337, "Replace Lunkenheimer Safety Valves with Consolidated Safety Valves"
- CR 97-1408, "Minor Modification 12-MM-337 Did Not Have An Unreviewed Safety Question Determination"
- Memorandum dated May 11, 1992, "Cook Nuclear Plant, 02-MM-337 - Replacement Valves No. 2-SV-79-CD1 & CD2, Review the Effects on Piping and Piping Support Systems"
- Memorandum dated July 30, 1992, "Cook Nuclear Plant, 12-MM-337 - Replacement Valves No. 1-SV-79-AB2 & CD1, Review the Effects on Piping and Pipe Support Systems"
- Critical Valve Replacement Suitability Worksheet, MM-337, SV-79-CD1 & 2
- CR 97-1494, "Missing Calculation"

b. Observations and Findings

The modification replaced the Lunkenheimer valves (1-SV-79-CD1, 1-SV-79-AB2, 2-SV-79-CD1 & CD2, and 2-SV-79-AB1 & AB2) with the Consolidated Dresser valves because the Lunkenheimer valves failed an inservice inspection (ISI) leakage test and like-for-like replacement valves were not available. The safety valves were classified as nuclear safety-related and seismic class I components.

On May 13, 1997, the inspectors reviewed a memorandum contained in the minor modification package which was dated May 11, 1992, and titled "Cook Nuclear Plant, 02-MM-337, Replacement Valves No. 2-SV-79-CD1 & CD2, Review the Effects on Piping and Pipe Support Systems," and a memorandum dated July 30, 1992, and titled "Cook Nuclear Plant, 12-MM-337 - Replacement Valves No. 1-SV-79-AB2 & CD1, Review the Effects on Piping and Pipe Support Systems." These memoranda stated that the Dresser replacement valves weighed 2.2 pounds (lbs) while the old Lunkenheimer valves weighed 1.5 lbs. The memoranda further stated that the Structural & Analytical Design Nuclear Section reviewed the effects of the additional weight of the replacement valves on the piping and pipe support systems in calculation number DC-D-12-ES-116 and found them to be acceptable. The inspectors requested to review calculation DC-D-12-ES-116; however, the licensee could not locate it in the designated file.

The licensee documented the missing calculation in CR 97-1494 and determined that calculation DC-D-12-ES-116 was not a formal calculation, but was generated as a storage place and subsequent retrieval method for a series of non-identical valve replacements that were being requested. The calculation file contained only the approval memo and a copy of the piping isometrics.

CR 97-1494 stated that an immediate walkdown of the modification was performed and found that the replaced valves were well supported. The licensee concluded that the additional weight of the replacement valves was not a significant consideration given that the actual spans of the piping were adequate. The licensee concluded that there was no operability or design basis concern. The inspectors also walked down the modification and noted that the valves were well supported.

The failure to assure that calculation DC-D-12-ES-116 had been performed was an example of a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which required, in part, that measures be established to assure that applicable design basis were correctly translated into specifications, drawings, procedures, and instructions, and that those measures provide for verifying or checking the adequacy of design (VIO 50-315(316)/97009-09c(DRS)).

c. Conclusions

The inspectors were concerned that the bases for the seismic design adequacy of the replacement safety valves in the diesel air start system were not retrievable.

E7.4 SI Pump Discharge Safety Valve Setpoint Decrease

a. Inspection Scope

The inspectors reviewed Design Change 12-DCP-0828, "Decrease Safety Valve Setpoints 1-SV-98N, 1-SV-985, 2-SV-98N, 2-SV-98S." The purpose of this design change was to lower the setpoint of the SI pump discharge safety valves from 1750 psig to 1700 psig to address an inconsistency between the SI pump design pressure listed in Table 6.2-5 of the UFSAR and Westinghouse design documentation. The following documents were reviewed by the inspectors:

- Design Change Package 12-DCP-0828, "Decrease Safety Valve Setpoints 1-SV-98N, 1-SV-985, 2-SV-98N, 2-SV-98S," Revision 0
- CR 96-1859, "Inconsistent SI Pump Design Pressures"
- UFSAR, Section 6.2, "Emergency Core Cooling Systems"

- Pacific Pumps Technical Data, Safety Injection Pumps, "Pump Shell Stress Calculations," October 15, 1969

- Calculation TH-90-01, "Maximum Static Pressure at SI & RHR Pumps," Calculation 0

- Safety Injection Pump Test Performance Curve 34554F, April 16, 1970

- Residual Heat Removal Pump Characteristic Curve N-318, June 18, 1971

- Drawing OP-1-5144-18, "Flow Diagram Containment Spray"

- Drawing OP-1-5142-25, "Flow Diagram Emergency Core Cooling (SIS)"

- Drawing OP-1-5143-39, "Flow Diagram Emergency Core Cooling (RHR)"

b. Observations and Findings

CR 96-1859 documented an inconsistency between the SI pump design pressure listed in Table 6.2-5 of the UFSAR and Westinghouse design documentation AEP/AMP-200/D. Table 6.2-5 of the UFSAR listed the SI pump design pressure as 1750 psig. Whereas, Westinghouse design documentation AEP/AMP-200/D (Attachment 6 to 12-DCP-0828) listed SI pump design pressure as 1700 psig. Pump shell stress calculations from the pump manufacturer, Pacific Pumps, determined that the SI pump casing design pressure was 1715 psig.

The inspectors reviewed the prompt operability determination for CR 96-1859 and noted that the SI pumps were declared operable based on sufficient safety margin included in the determination of design pressure. The safety margin included in the determination of design pressure was evident based on the fact that a hydrostatic test was conducted at 1.5 times the design pressure with no apparent problems to the SI pump casings.

The inspectors verified that the maximum SI pump discharge pressure would not exceed the new setting of the SI pump discharge safety valves (1700 psig).

c. Conclusions

The design change was conducted in accordance with station procedures. No examples of inadequate review of input values and assumptions were identified by the inspectors.

X1 **Exit Meeting**

An exit meeting was held on May 23, 1997, to discuss the findings of the inspection with licensee management. The licensee indicated that none of the material reviewed during the inspection was proprietary. Licensee personnel who attended the exit meeting are included on the following Partial List of Persons Contacted.

PARTIAL LIST OF PERSONS CONTACTED

E. Fitzpatrick, Executive Vice President
A. Blind, Site Vice President
J. Sampson, Plant Manager
B. Abbgy, Environmental Supervisor
M. Ackerman, Manager, Nuclear Licensing
J. Allard, Maintenance Superintendent
T. Andert, Chemistry Staff Engineer
K. Baker, Production Engineering Director
A. Barker, Performance Analysis Supervisor
J. Benes, Manager, Balance-of-Plant Mechanical Systems
J. Boesch, Maintenance Superintendent
J. Bond, Stores Supervisor
L. Boone, Shift Manager
S. Brewer, Manager Regulatory Affairs
W. Burgess, Operations, Production Supervisor, Administration
R. Blyth, Operations
R. Carruth, Manager, Electrical Design
M. Depuydt, Licensing Coordinator
M. Eberhardt, Licensing Activity Coordinator
D. Etheridge, Assistant Shift Supervisor
R. Gillespie, Operations Superintendent
M. Greendonner, Fire Protection Supervisor
P. Halverson, Senior Scheduler
W. Hannah, General Supervisor, Buildings and Grounds
K. Henderson, Supervisor, Electrical Maintenance
S. Hodge, Manager Work Control
J. Jeffrey, Manager, Configuration Management
J. Kobyra, Chief Nuclear Engineer
S. Koshar, Operations, Unit Supervisor (Refueling)
R. Leonard, System Engineer
Q. Lies, System Engineer
B. Little, Plant Performance Assurance
D. Loope, Training Manager
P. Mangan, Manager, Mechanical Design
R. Mankowski, Materials Management
W. McCrory, Senior System Engineer
D. Morey, Chemistry Superintendent
J. Nadeau, Plant Performance Assurance Supervisor
K. Newell, System Engineer
F. Pisarsky, Manager, Mechanical Component Engineering
T. Postlewait, Site Engineering Support Manager
T. Quaka, Project Management & Instrument Services
R. Reynnells, Operations Senior Program Analyst
R. Rickman, Operations, Production Supervisor, Work Control
P. Russell, Plant Protection Superintendent
M. Russo, Performance Analyst, Plant Performance Assurance

P. Schoepf, Manager Safety-Related Systems
J. Schrader, Operations Performance Engineer
C. Scott, Human Resources Manager
L. Smart, Licensing Coordinator
D. Spencer, Performance Engineering
M. Stark, Manager, Performance Testing
J. Tilly, Assistant Shift Supervisor
G. Tollas, Operations Shift Manager
L. VanGinhoven, Materials Management Superintendent
T. Walsh, General Supervisor, Maintenance
J. Wiebe, Manager Engineering and Analysis
S. Wolf, Internal Performance Supervisor
W. Zemo, Manager, Preventive Maintenance

ITEMS OPENED AND CLOSED

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50-315/97009-01	NCV	Missed TS 4.1.1.5.b requirement to determine Tavg
50-315/97009-02	NCV	Procedure not followed for placement of annunciator response procedures
50-316/97009-03	VIO	Inadequate instructions for removing 2AB EDG inverter from service
50-315(316)/97009-04	NCV	Inadequate instructions for procedures with equipment names different than plant labelling
50-315(316)/97009-05	NCV	Procedure on sealing valves not followed
50-316/97009-06	NCV	Failure to follow procedure during 2AB EDG voltage regulator maintenance

ITEMS OPENED

50-315(316)/97009-07	VIO	Procedure on temporary modifications was not followed, Criterion V
50-315(316)/97009-08	IFI	NRR to determine if seasonal modification is really a permanent change
50-315(316)/97009-09	VIO	3 examples where review of modification packages missed discrepancies, Criterion III

LIST OF ACRONYMS

AEO	Auxiliary Equipment Operator
AEP	American Electric Power
AFW	Auxiliary Feedwater
ANSI	American National Standard Institute
CAS	Containment Annunciator Subpanel
CFR	Code of Federal Regulations
CCW	Component Cooling Water
CR	Condition Report
CS	Change Sheet
°F	Degrees Fahrenheit
DCP	Design Change Package
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
ECP	Engineering Control Procedure
EDG	Emergency Diesel Generator
EHP	Plant Engineering Head Procedure
ESW	Essential Service Water
IFI	Inspection Followup Item
IHP	Instrument & Control Head Procedure
ISI	Inservice Inspection
JO	Job Order
LCO	Limiting Condition for Operation
lbs	Pounds
MDAFW	Motor Driven Auxiliary Feedwater
MM	Minor Modification
MMP	Material Management Procedure
MOVATS	Motor Operated Valve Analysis and Test System
NCV	Non-Cited Violation
NESW	Non-Essential Service Water
NRC	Nuclear Regulatory Commission
OAP	Office Administrative Procedure
OHI	Operations Head Instruction
OHP	Operations Head Procedure
OPM	Operations Process Manual
OPP	Operating Philosophy and Practices
OSTI	Operational Safety Team Inspection
PDR	Public Document Room
PMI	Plant Manager Instruction
PMP	Plant Manager Procedure
PMSO	Plant Manager Standing Order
PMT	Post-Maintenance Testing
PNSRC	Plant Nuclear Safety Review Committee
POG	Plant Operations Group
PGG	Procedure Group Guidelines
psig	Pounds Per Square Inch-Gauge

QA	Quality Assurance
RO	Reactor Operator
SCR	Silicon Controlled Rectifier
SI	Safety Injection
SRM	Safety Review Memorandum
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
Tavg	Reactor Coolant Average Temperature
TDAFW	Turbine Driven Auxiliary Feedwater
TS	Technical Specification
2AB EDG	Unit 2 AB Emergency Diesel Generator
UFSAR	Updated Final Safety Analysis Report
WIN	Work It Now