ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/96-01
50-368/96-01

Licenses: DPR-51
NPF-6

Licensee: Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: January 21 through March 2, 1996

Inspectors: K. Kennedy, Senior Resident Inspector
S. Campbell, Resident Inspector

Approved: Roger ... for T. Reis 4/8/96
T. Reis, Acting Chief, Project Branch C Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, followup - maintenance, and followup - engineering.

Results (Units 1 and 2):

Plant Operations

- Control room operators continued to operate the units very well. Unit 1 operators performed well when challenged with problems which required reductions in power on several occasions, and improvements were noted in the accuracy and detail in the Unit 2 station logs (Section 2.1).

- A decline was noted in plant housekeeping. The licensee promptly addressed the inspectors concerns and increased management attention was directed toward emphasizing and improving plant housekeeping (Section 2.2).

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- The implementation of the Category E locked valve program was satisfactory (Section 2.3).

- The licensee continued to troubleshoot a repetitive communication error between the control element assembly (CEA) computer and the core protection calculators (CPCs) (Section 2.4).

- Plant impact and contingency actions were thoroughly developed and discussed for maintenance on a Unit 2 turbine control system pressure transmitter which was identified as having a high potential for causing a main turbine trip (Section 3.2).

Maintenance

- Although the leak repair of a Unit 1 feedwater isolation control valve was performed properly and in accordance with applicable procedures, several administrative errors in the job order (JO) package were identified which indicate a need for further management attention in this area (Section 3.3).

- Inadequate maintenance procedures for the installation of a position indicator, and an inadequate postmaintenance test following its installation in 1994, resulted in an unexpected degradation of closing thrust on a Unit 2 high pressure safety injection valve (HPSI). The failure to perform valve testing following installation of the position indicator bypassed a key barrier to ensuring that safety-related valves were not adversely affected as a result of this maintenance activity (Section 7.1).

- The failure to perform routine preventive maintenance on the heat trace system associated with Unit 1 once-through steam generator pressure sensing lines resulted in the inoperability of Train B of the emergency feedwater initiation and control (EFIC) system and entry into a Technical Specification (TS) action to shut down the unit in 12 hours. The licensee had prior opportunities to address the deficiency in 1990 and 1995. The failure to perform the required preventive maintenance was identified as a violation of TS 6.8.1.a (Section 7.2).

- The licensee responded appropriately to the failure of a safety-related breaker by performing inspections of a sample of breakers on both units to determine if similar conditions related to the cause of the failure existed (Section 7.3).

Engineering

- The licensee addressed uncertainties in the high logarithmic power trip setpoint on Unit 2 and took appropriate compensatory actions (Section 5).

Plant Support

- Based on inspectors' observations and routine tours of the radiologically controlled area and site security perimeter, the licensee's implementation of their radiation protection and security programs continued to be properly conducted (Section 6).

Summary of Inspection Findings:

New Items

- Two violations were identified, 368/9601-02 and 313/9601-03 (Sections 7.1 and 7.2).

- Unresolved Item 368/9601-01 (Section 5)

Closed Items

- Inspection Followup Item (IFI) 368/9406-05 (Section 8)

Attachments:

1. Persons Contacted and Exit Meeting
2. List of Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent reactor power. Power was reduced to 80 percent on January 26, 1996, and further reduced to 60 percent to repair condenser tube leakage. The plant was returned to 100 percent power on January 29. On January 31, reactor power was again reduced to 80 percent to repair condenser tube leakage. Power was returned to 100 percent on the same day, but later reduced to 90 percent to address level control problems in a high pressure feedwater heater. The plant was returned to 100 percent reactor power on February 6. On February 15, operators reduced power to 80 percent to repair condenser tube leakage. Power was further reduced to 40 percent on February 17 to replace a faulty component in the Main Feedwater Pump B control circuitry. The plant was returned to 100 percent on February 18 where it remained through the end of the inspection period.

1.2 Unit 2

Unit 2 remained at approximately 98 percent power throughout the inspection period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

This inspection was performed to ensure that the licensee operated the facility safely and in conformance with license and regulatory requirements and that the licensee's management control systems effectively discharged the licensee's responsibilities for safe operation.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. An independent verification of the status of safety systems, a review of TS limiting conditions for operation, and a review of facility records were also performed.

2.1 Control Room Observations

Control room operators continued to operate the plants very well. Crew briefs conducted at the beginning of each shift were thorough, informative, and provided complete information regarding plant status, emergent and ongoing problems, and scheduled activities. The briefs included a review of new condition reports (CRs) and recent industry events. Support for operations by other organizations was demonstrated by the presence and participation of chemistry and system engineering personnel at these briefings.

Unit 1 operators performed well when challenged with several plant maneuvers required during this inspection period to address main condenser tube leaks, feedwater heater level control problems, and main feedwater pump control circuitry repairs. The inspectors noted an improvement in the accuracy and level of detail in the Unit 2 station logs.

2.2 Plant Tours

The inspectors noted a slight decline in plant housekeeping during this inspection period. Specifically, in the Unit 1 lower south piping penetration room, the inspectors observed hoses lying on the floor that were not connected to any equipment, extension cords routed through the room that were not in use, and tools. Tools were also identified in each of the three makeup pump rooms. In addition, vice grips were identified on an instrument line isolation valve associated with the Unit 2 Charging Pump 2P36A. The valve was missing its handwheel and had a deficiency tag hanging from it which indicated that the valve needed to be repaired. The deficiency tag was dated July 31, 1995. The inspectors determined that the valve had not been repaired due to a parts hold, but was scheduled for replacement on February 6, 1996. The inspectors verified that the valve had been replaced. The licensee indicated that leaving the vice grips on the valve did not meet management's expectations.

These and other discrepancies identified by the inspectors were promptly addressed or corrected by the licensee. In addition, the licensee initiated tours of the plant to identify and correct additional housekeeping problems.

The inspectors concluded that the level of housekeeping in the plant had declined. Evidence of increased management attention was noted by the end of the inspection period.

2.3 Unit 2 - Implementation of Category E Valve Program

On January 31, 1996, the inspectors reviewed the Category E deviation log book to determine if Category E valves, valves whose locked positions were required for safe shutdown of the plant, had been appropriately tracked and restored to their proper position following manipulation. A walkdown of a sample of Category E valves by the inspectors revealed that the valves were appropriately tracked and restored to their proper locked positions in accordance with Procedure 1015.035, Revision 1, "Valve Operations," Attachment F, "Category E Valve Position Alignment Initial Check Without Shutdown Cooling Valves."

2.4 Repeated CPC Channel Sensor Failures

Since 1992, the licensee has written 26 CRs documenting a recurring communication error between Control Element Assembly Computer (CEAC) 2 and the four CPC channels. Two CEACs (CEACs 1 and 2) calculate penalty factors based on relative positions of a CEA within a subgroup and the relative positions among each CEA group. Modems and fiber optic wires connected between the CEACs and the CPCs are used to transmit these penalty factors to CPC

Channels A, B, C, and D, where the CPCs use the penalty factors to calculate departure from nucleate boiling ratio and local power density values.

The communication error caused the operators to receive channel sensor failure alarms, but the alarms would immediately clear before the source of the problem could be identified. Each CPC channel was randomly affected, but the problem always involved CEAC 2. The repetitive problem prompted the licensee to perform extensive troubleshooting efforts to isolate the cause. The intermittent communication error did not render the reactor protection system inoperable; however, because the communication error was a recurring problem, the inspectors reviewed the licensee's efforts in addressing the anomaly.

The inspectors conducted interviews and reviewed the licensee's journal, which recorded their troubleshooting efforts. The licensee's efforts included the following:

- On February 16, 1993, CPC Channel D received an intermittent failure. The licensee removed a circuit board from CEAC 2 and ran a computer diagnostic on the board. The licensee was unable to detect a problem with the circuit board.

- On March 23, 1995, CPC Channel A received an intermittent failure. The licensee removed and replaced the circuit board from CEAC 2 with a spare circuit board. Diagnostic testing was performed on the removed circuit board for 2 weeks and no errors were found.

- On March 28, the licensee replaced the central processing unit from CEAC 2. On April 1, an intermittent failure of CPC Channel A occurred again.

- On July 12, following vendor recommendations, the licensee removed a "watchdog" timer relay from CEAC 2, installed a spare timer, and installed the previously removed CEAC 2 "watch dog" timer relay into CEAC 1. The "watch dog" timer relay monitors the computer's internal clock to verify that the computer continues to operate. An intermittent failure of CPC Channel C was experienced on July 14.

- On July 18, the licensee measured the power in the fiber optic modems in CEAC 2 and found that the power readings were acceptable. However, the licensee found the software program loader in the macroloader board corrupted and replaced the macroloader.

- On July 19, the licensee replaced the CEAC 2 "watch dog" timer circuit board.

- During Refueling Outage 2R11 in October 1995, the licensee exchanged several components between CEAC 1 to CEAC 2. These included nine circuit cards, two bus terminator cards, cables, expansion cables, and fiber optic modems. Following the refueling outage, the licensee has continued to experience channel sensor failures.

The licensee planned to implement a temporary alteration in mid-March 1996 to switch CEACs 1 and 2 inputs into each CPC channel to determine if the problem originated from the CPC or the CEAC software. The licensee stated that this temporary alteration would require a safety evaluation and changes to Unit 2 operating procedures. The temporary alteration will be implemented for 30 days. The inspectors concluded that the licensee is appropriately addressing the CEAC2/CPC communication anomaly.

3 MAINTENANCE OBSERVATIONS (62703)

3.1 Units 1 and 2 - Maintenance Observations

During this inspection, the inspectors observed or reviewed the selected maintenance activities listed below to verify compliance with regulatory requirements, including licensee procedures; required quality control department involvement; proper use of safety tags; proper equipment alignment; appropriate radiation worker practices; use of calibrated test instruments; and proper postmaintenance testing:

- Unit 1 - JO 00944757, "Calibration of Control Rod Drive Undervoltage Relays," performed on February 26.

- Unit 1 - JO 00941740, performed in accordance with Procedure 1405.017, Revision 10, "Unit 1 Reactor Trip Breaker Inspection," on February 26.

- Unit 1 - JO 00944204, "On-line leak repair of a body to bonnet leak on Valve CV-2680," performed on January 29.

- Unit 2 - JO 00942795, "Troubleshooting and Repair of 2RITS 8750-1, Control Room Inlet Air Radiation Monitor," performed on February 29.

- Unit 2 - JO 00942220, "Calibration of Electro-hydraulic Control Pressure Transmitter 2PT-0251," performed on February 27.

The inspectors confirmed that maintenance personnel performed the activities according to the JO requirements. Selected observations from review of maintenance-related activities are discussed below.

3.2 Calibration of Electrohydraulic Control Pressure Transmitter 2PT-0251 (JO 00942220)

On February 27, 1996, the licensee calibrated Pressure Transmitter 2PT-0251 while the plant was at full power. The pressure transmitter, which is a part of the turbine control system, senses steam supply header pressure to close turbine control valves as header pressure decreases. The licensee had replaced the transmitter in the previous refueling outage and had to wait until the plant reached steady state operation to adjust the pressure transmitter span.

The licensee considered the calibration a high risk evolution because of the potential for tripping the turbine generator. The licensee developed a risk assessment in accordance with Planning and Scheduling Liaison Desk Guide (Unit 2) 2OPG-005, which was used to evaluate potential impact on plant operations and TSs and to develop contingency actions to mitigate unforeseen consequences or events. The operators briefed the risk assessment evaluation prior to performing the calibration. During the control room brief, the operator and instrumentation and control (I&C) technician duties were discussed in addition to the recovery actions described in the loss of turbine abnormal operating procedure. The inspectors concluded that the operators conducted a good briefing.

The technicians established communications with the control room and adjusted the pressure transmitter span using calibrated equipment. The inspectors observed the I&C technicians perform the calibration and verified that the calibration was performed in accordance with the JO instructions. The pressure transmitter was successfully calibrated and restored to service.

3.3 Unit 1 - Online Leak Repair of Valve CV-2680

During this inspection period, the inspectors reviewed JO 00944204 related to the online leak repair of a body-to-bonnet leak on Valve CV-2680, the feedwater isolation control valve to Steam Generator A. The online leak repair was performed on January 29, 1996.

The inspectors reviewed Maintenance Engineering Request 1M-96-024, which indicated that Procedure 1025.015, "On Line Repair Procedures," Supplement 3, "Bonnet/Flange (Metal to Metal) Drill and Tap," was to be used to perform the leak repair. Procedure 1025.015, Attachment 1, "On-Line Repair Control and Documentation," also indicated that the repair was to be performed in accordance with Supplement 3. A copy of Supplement 3 was included with the instructions in the JO. Supplement 3 allowed personnel to drill and tap into the face of the bonnet or flange every 90° with prior approval from maintenance engineering. However, the inspectors noted that drilling and injection of sealant had actually been performed at each of the 24 stud holes on this 18-inch valve.

Although Supplement 3 was included in the JO package, the licensee informed the inspectors that the leak repair had been performed in accordance with Supplement 4, "Metal to Metal (Flat Face) - Drill and Tap," which allowed drilling and injection of sealant at each stud. This was consistent with what the inspectors had observed in the plant. The instructions to use Supplement 3 was an administrative error made during the development of the maintenance engineering request and the JO. Maintenance personnel had planned on using Supplement 4 for the work and had discussed its use prior to performing the job. They did not realize that the incorrect supplement was included with the JO instructions.

The inspectors concluded that the leak repair of Valve CV-2680 was properly performed in accordance with Procedure 1025.015, Supplement 4, and that administrative errors were made in the preparation of the maintenance engineering request and the JO related to this work. The identification of a second example of a similar administrative error by the licensee indicates that increased attention may be warranted in this area.

4 SURVEILLANCE OBSERVATIONS (61726)

Units 1 and 2 - Surveillance Test Observations

The inspectors reviewed the tests listed below to verify that the licensee conducted surveillance testing of systems and components in accordance with the TS and approved procedures:

- Unit 2 - Procedure 2304.040, "Plant Protection System Channel D Test," on January 30.
- Unit 1 - Procedure 1304.127, Revision 8, "Unit 1 RPS-C/CRD Breaker Trip Test," and Procedure 1304.128, Revision 8, "Unit 1 RPS-D/CRD Breaker Trip Test," performed on February 26, 1996.

The inspectors concluded that the licensee safely performed these surveillance tests in accordance with established procedures.

5 ONSITE ENGINEERING (37551)

Unit 2 - Decalibration of Logarithmic Power Channels

On February 9, 1996, Combustion Engineering, Incorporated informed the licensee that decalibration effects, including power roll, temperature shadowing, and boron concentration, had not been previously accounted for in the procedures for calibrating the logarithmic power channels or in establishing the reactor trip setpoint associated with the high logarithmic power trip. This called into question the adequacy of the high logarithmic power trip setpoint. A similar finding had been identified at Waterford 3. As a result, Combustion Engineering recommended that the licensee decrease their high logarithmic power trip setpoint by one decade. They indicated that this one decade decrease was conservative in that it was much larger than the possible effects of decalibration.

The high logarithmic power reactor trip setpoint, which protects the integrity of fuel cladding and the reactor coolant system pressure boundary in the event of an unplanned criticality from a shutdown condition, is normally less than or equal to 0.75 percent of rated thermal power. The high logarithmic power trip can be manually bypassed when power is greater than 10E-4 percent of full power. Although TSs do not require that the logarithmic power channels be operable in Mode 1, they are required to be operable in Modes 2, 3, 4, and 5 during a startup if the reactor trip breakers are closed.

In response to Combustion Engineering's recommendation to reduce the high logarithmic power trip setpoint by one decade, the licensee revised procedures to adjust the trip setpoint to 0.075 percent of rated thermal power prior to closing the reactor trip circuit breakers if the plant was in Modes 3, 4, or 5. As a long-term action, the licensee planned to conduct further analysis to quantify the decalibration of the logarithmic power channels and determine its effect on the reactor trip setpoints. The compliance with TS due to the decalibration of the high logarithmic power channels is an unresolved item (368/9601-01).

The inspectors determined that the engineering and operations personnel were proactive in addressing uncertainties regarding calibration of logarithmic power channels and took appropriate compensatory actions as recommended by Combustion Engineering.

6 PLANT SUPPORT ACTIVITIES (71750)

The inspectors performed routine inspections to evaluate licensee performance in the areas of radiological controls, chemistry, and physical security.

During routine plant tours, the inspectors verified that radiological protection personnel maintained appropriate controls over high radiation areas and that plant areas were properly posted. Licensee activities, within radiologically controlled areas, were observed and the inspectors found that personnel followed appropriate radiation worker practices. The inspectors verified that effluent and environmental radiation monitors remained operable and that appropriate compensatory actions were taken for those which were out of service.

The inspectors observed that the licensee's security program properly maintained the integrity of protected area barriers and maintenance of isolation zones around these barriers.

7 FOLLOWUP - MAINTENANCE (92902)

7.1 Unit 2 - HPSI Valve Thrust Degradation

On January 11, 1996, the licensee was performing postmaintenance testing following a valve packing adjustment and identified that the thrust output of the HPSI Header Flow Control Valve 2CV-5055-1 actuator had degraded since the last time it had been tested. Specifically, the torque switch tripped at a thrust output of 6,761 pounds on January 11 compared with a value of 8,692 pounds in April 1994. This degradation in thrust occurred only when the valve was going closed. There was no degradation in the open direction. The licensee found that the measured thrust value did not meet the minimum thrust value of 7,764 pounds contained in Design Engineering Calculation V-2CV-5055-10, Revision 4. However, they concluded that the valve remained operable because there was no effect on performance in the open direction. In addition, the licensee performed an engineering evaluation using the degraded thrust and determined that the valve would have performed its containment isolation function to close.

The licensee determined the cause of the degraded thrust to be the improper installation of the mechanical-driven position indicator (MDPI) on the valve actuator. The MDPI, which provides local and remote valve position indication, has a drive gear which is driven by the actuator. When the MDPI housing is attached to the valve actuator, shims may be required to ensure that the proper clearances are established between the MDPI drive gear and the actuator drive sleeve. The licensee found that the MDPI drive gear inappropriately contacted the drive sleeve of the actuator and caused sufficient binding to degrade thrust in the close direction. When the licensee removed the MDPI drive gear from Valve 2CV-5055-1 and retested the valve, they found that thrust values returned to expected levels. The licensee also found that, although valve operation test and evaluation system (VOTES) testing had been performed after the valve and actuator were installed during Refueling Outage 2R10 (April 1994), it was not performed following installation of the MDPI several months later. Because Valve 2CV-5055-1 was one of four HPSI valves replaced in Refueling Outage 2R10, the licensee sought to determine if a similar problem existed with Valves 2CV-5015-1, -5016-2, and -5056-2. Review of test data acquired in October 1995 for Valve 2CV-5056-2 revealed that there was no degradation of thrust. Valve 2CV-5015-1 was tested on January 11, 1996, and no degradation was identified. Valve 2CV-5016-2 was also tested and degraded thrust was identified, although not as severe as Valve 2CV-5055-1.

As described previously, the licensee replaced four of the eight HPSI header isolation valves and actuators during Refueling Outage 2R10. Although the design change package written to replace these valves included the installation of MDPIs on the actuators, the licensee did not receive them from the vendor in time to install them with the new actuators. The new valves and actuators were installed without the MDPIs, and VOTES testing was performed on these valves in April 1994. The MDPIs arrived onsite at a later date and were installed in October 1994. Following installation of the MDPIs, the licensee stroked the valves and verified that the position indicators were set properly. VOTES testing was not performed at that time because the licensee was unaware that the improper installation of the MDPIs could affect actuator performance. In addition, the vendor did not list the MDPI as a critical component which could affect the performance of the valve actuator.

The inspectors reviewed Design Change Package 93-2012; JOs 00909976, 00910408, 00910409 and 00910410 associated with the installation of HPSI Valves 2CV-5015-1, -5016-2, -5055-1, and -5056-2, respectively, in Refueling Outage 2R10; Procedure 1403.038, Revision 11, "Unit 1 and Unit 2 MOV Testing and Maintenance of Limitorque SMB-000 Actuators," for performing testing and maintenance on these types of actuators; and Vendor Technical Manual TM L200.0010, "Limitorque Valve - Controls and Operation," for these valve actuators and found no installation instructions for the MDPIs. Although the licensee believed that this activity was within the skill of the craft, they were unaware of the critical nature of the alignment of the MDPI drive gear with the actuator drive sleeve. This was reinforced by the fact that the vendor technical manual did not contain instructions for the MDPI installation. The inspectors concluded that the licensee's procedures for the installation of the MDPIs were inadequate in that they did not provide instructions for the proper alignment of the MDPIs with the valve actuators, resulting in the improper installation of MDPIs on two HPSI valves and the degraded performance of these two valves.

The inspectors also found that the licensee failed to perform adequate postmaintenance testing of the valves after the MDPIs were installed in October 1994. Following installation of the MDPIs in October 1994, the licensee stroked each of the valves to verify that the MDPIs provided proper valve position indication. VOTES testing was not performed. The licensee stated that they did not consider that VOTES testing was necessary since they had installed MDPIs in the past and had not experienced any problems. They also felt that the MDPI had a negligible effect on the performance of the valve actuator. The licensee found, however, that previous MDPI installations had been custom fit to the actuator by the manufacturer. The MDPIs installed in October 1994 were not supplied with the actuators and, therefore, were not custom fit to the actuators by the manufacturer. The failure to perform VOTES testing following installation of the MDPIs bypassed a key barrier to ensuring that these safety-related valves were not adversely affected as a result of this maintenance activity. This was particularly significant given the potential for the introduction of a common mode failure of these safety-related valves as a result of the improper installation of the MDPIs.

The inspectors determined that the licensee's troubleshooting activities were effective in identifying the cause of the degraded thrust and that they took prompt and effective action to correct the condition. In their root cause analysis, the licensee-identified root causes were consistent with those identified by the inspectors. In addition, the licensee's long-term corrective actions to prevent recurrence were broad and comprehensive. These actions included revising procedures to include instructions for MDPI installation, providing proper retest requirements for valve actuators, identifying all possible maintenance activities performed on motor-operated valve program actuators that should have postmaintenance VOTES testing, reviewing all motor-operated valve program valve work histories to determine if any maintenance had been performed since the last VOTES test, and reviewing the modification and maintenance programs and procedures to ensure adequate controls exist for provisional release of modifications and maintenance and the completion of open items.

TS 6.8.1.a states, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 9, states that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. The failure to have adequate procedures for the installation of the MDPIs and the failure to perform an adequate test to verify the proper operation of the valves following the installation of the MDPIs are two examples of a TS 6.8.1.a violation (368/9601-02).

7.2 Unit 1 - Frozen EFIC Pressure Sensing Lines

On February 4, 1996, while performing control room channel cross checks, the operators noticed that EFIC Pressure Transmitters PT-2618B and -2668B drifted high and then failed. EFIC Pressure Transmitter PT-2618B provides input to EFIC Channel B to automatically initiate emergency feedwater for a low Once-Through Steam Generator A pressure, main steam line isolation, and provides vector logic for emergency feedwater Flow Control Valves CV-2645 and -2647. EFIC Pressure Transmitter PT-2668B provides input to Channel D for the same functions as Channel B, but provides vector logic for Isolation Valves CV-2670 and -2626. These channels failed because two 3/8-inch pressure sensing lines, used to sense Once-Through Steam Generator A pressure, froze and rendered Train B of the EFIC system inoperable. A portion of the pressure sensing lines were located in the outside environment. Ambient temperature was approximately 7°F when the operators identified the inoperable pressure channels.

The licensee entered TS Table 3.5.1-1, Note 1, which required that they place the reactor in a hot shutdown condition within 12 hours, and began an investigation into why the sensing lines froze. The licensee found that five contacts associated with the heat trace system had failed to close and energize the heat trace system and an alarm circuit. Two contacts close to energize the primary heat trace circuit when the temperature controller senses temperatures below 60°F and two contacts close to energize the secondary heat trace system if the primary circuit fails and the temperature falls below 50°F. The energized heat trace system warms and protects the pressure sensing lines during freezing conditions. The fifth contact, the alarm relay contact, closes to energize an alarm circuit to actuate annunciators at the freeze protection panel and in the control room when the temperature falls below 40°F. I&C technicians manually energized the heat trace circuits and the pressure indications returned to normal. EFIC Train B was restored to service and the operators exited TSs less than 4 hours after it was declared inoperable. Upon further investigation, the licensee determined that loose rivets caused the primary and secondary heat trace circuitry contacts to bind, thereby, preventing them from closing. Because the alarm contacts are sealed in a casing, the licensee was unable to determine the contact's failure mode. The licensee repaired or replaced the bad contacts and verified that the heat trace was functioning properly.

The licensee initiated CR 1-96-0034 to document the inoperable pressure channels. In their root cause evaluation, the licensee found that preventive maintenance had never been performed on the EFIC heat trace system. However, the licensee discovered that Preventive Maintenance Task 018771 to inspect, clean, and functionally test all thermostat controllers listed in the system information management system, as well as the EFIC heat trace system, had been written but not implemented.

Preventive Maintenance Task 018771 was developed as a result of an action item from CR C-94-0001, which documented that critical system relays were not being replaced at the intervals specified in the preventive maintenance engineering evaluation program. Action Item 14, which was due to be completed on April 30, 1996, assigned system engineering to perform a comprehensive evaluation of systems to determine if preventive maintenance tasks for these systems needed to be generated. During their investigation, they found that a preventive maintenance task should have been developed for the EFIC heat trace and other systems. The development of Preventive Maintenance Task 018771 was completed in November 1995.

The inspectors reviewed Task 018771, found that the task was required to be scheduled in conjunction with freeze protection preventive maintenance, and noted that the task was due to be worked in June of 1996. The inspectors questioned why Preventive Maintenance Task 018771 was not immediately implemented after development. The licensee stated that the preventive maintenance task, which also includes preventive maintenance on boric acid system temperature controllers, was scheduled when the boric acid heat trace circuit preventive maintenance was performed. The preventive maintenance on the boric acid temperature controllers had already been completed before November 1995. Therefore, the planners assigned Priority 3 (routine) JO 00943478 to be worked during the next preventive maintenance on the boric acid freeze protection system beginning in June 1996.

The licensee also found that Design Change Package 82-1052, which originally installed the EFIC heat trace system, recommended shiftly and monthly checks of the EFIC temperature controllers, yearly continuity checks of the heat trace cable, and annual inspections of the insulation. The licensee confirmed these recommendations had not been implemented. The inspectors reviewed Procedure 1015.003A, "Unit 1 Operations Logs," Attachment F, "Miscellaneous Required Readings," and Procedure 1307.037, "Unit 1 Freeze Protection Testing," to determine if the EFIC heat trace system was included for periodic checks and found that EFIC was not addressed in these procedures.

The inspectors reviewed the CR system data base from 1988 forward to determine if EFIC or other TS-related systems had been impacted as a result of heat trace circuit malfunctions. The inspectors found that CR 1-90-0343, dated August 24, 1990, identified that the boric acid heat tracing temperature instruments were not checked or calibrated on a routine basis. Action Item 8 to the CR required that Unit 1 TS-related systems be evaluated to identify heat trace circuits that could impact system operability. The action item response stated that no new heat trace circuits were identified which required preventive maintenance tasks. The inspectors questioned why the EFIC heat trace system was not identified in the response to Action Item 8. The licensee, who also identified this CR during their root cause evaluation, stated that the preventive maintenance task for the heat trace circuits for the EFIC pressure sensing lines could have been identified as a result of the action item; however, they stated that the focus of the CR was heat tracing of boric acid flowpaths, not instrumentation lines, and considered this a missed opportunity in identifying the preventive maintenance task for EFIC heat trace. The inspectors concluded that, given the action of CR 1-90-0343 to evaluate Unit 1 TS-related systems to identify heat trace circuits that could impact system operability, the licensee should have identified the EFIC system heat trace circuits as ones which required preventive maintenance.

The inspectors concluded that the licensee's failure to conduct periodic preventive maintenance on the EFIC heat trace system resulted in its failure and rendered EFIC inoperable due to the freezing of two once-through steam generator pressure sensing lines. In addition, the licensee had an opportunity to identify this lack of preventive maintenance as a result of an action item in CR 1-90-0343. And, although the failure to perform preventive maintenance on the system was identified as a result of CR C-94-0001 and a preventive maintenance task developed, the licensee failed to implement the task prior to the freezing of the pressure sensing lines on February 4, 1996.

Unit 1 Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33 (Safety Guide 33, November 1972). Section I, 1 and 2 of Safety Guide 33 states, in part, that maintenance which can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures appropriate to the circumstances. Preventive maintenance schedules should be developed to specify inspections of equipment or replacement of parts that have a specific lifetime. The failure to conduct preventive maintenance on the EFIC heat trace system is a violation of TS 6.8.1.a (313/9601-03).

The inspectors concluded that the licensee took immediate corrective action to repair and replace the temperature controller contacts and restore the EFIC system. The licensee also added a daily check of the temperature controllers to the outside auxiliary operators log. The inspectors considered that Task 018771 was effective in testing the EFIC heat trace circuit contacts. However, the inspectors noted that the task did not include a test of the alarm contacts, which the licensee had already recognized and had planned to submit a change to the task to include this check. Some additional corrective actions as a result of this event included:

- evaluating the applicability of this condition to Unit 2 heat trace circuits and alarms.

- evaluating the need for the EFIC heat trace inspections recommended in Design Change Package 82-1052 and incorporating them into the Unit 1 operations logs and preventive maintenance tasks,

- performing a comprehensive review of all freeze protection systems used on safety systems to determine if further preventive maintenance tasks were required,

- revising Preventive Maintenance Task 018771 to be scheduled in September of each year, and

- evaluating the use of more reliable contacts in the heat trace circuits.

The inspectors concluded that the licensee's corrective actions were acceptable.

7.3 Unit 1 - Failure of Makeup Pump P36B Breaker

On February 14, 1996, Unit 1 operators, while attempting to stop Makeup Pump P36B from the control room, discovered that supply circuit Breaker A-307 to the pump motor failed to open. Attempts to open the breaker locally using the breaker control switch failed and the operators successfully tripped the breaker manually. The licensee found that the breaker's trip arm screw had fallen out of the trip arm. With this screw missing, the trip coil mechanism could not rotate the trip arm shaft to cause the breaker to open. The licensee removed the breaker and replaced it with a spare breaker. The trip arm screw is positioned in accordance with the vendor technical manual and then secured in place using a locking screw. This locking screw is inserted behind the trip arm screw and tightened against the trip arm screw to keep it in place. The licensee found that the locking screw was in place on Breaker A-307. The trip arm screw also had a type of locking tab on the threads to prevent it from backing out.

The primary concern associated with the failure of this breaker to open was that the breaker would not perform its protective function in the event of a fault or overload condition. In addition, in the event of an engineered safeguards actuation signal, Breaker A-307 would not have opened in response to the load shed signal for Bus A-3 and Makeup Pump P36B would have started as soon as the emergency diesel generator output breaker closed to energize the bus. The licensee determined that the failure of the breaker to open rendered the breaker, Emergency Diesel Generator 1, and Safety Bus A-3 inoperable. However, operators manually opened the breaker and restored the operability of the emergency diesel generator and the safety bus prior to exceeding any TS action statements.

The licensee was unable to identify what caused the trip arm screw to fall out. The inspectors reviewed the maintenance history for Breaker A-307 and found that maintenance was performed on the breaker on January 6, 1996, to replace a power switch. The breaker was successfully cycled electrically following completion of this maintenance. Breaker A-307, a General Electric Magne-blast circuit breaker, was last refurbished by General Electric in 1990 and the licensee had performed both preventive and corrective maintenance on the breaker since that time. However, the licensee indicated that none of the maintenance activities performed since the valve was last refurbished in 1990 would have resulted in the removal or adjustment of the trip arm screw.

In response to the failure of Breaker A-307 to open, the licensee inspected a total of 37 General Electric Magne-blast breakers utilized on both Units 1 and 2 and did not identify any missing trip arm screws. They did identify some screws that were not tight against the locking screw, but the trip arm screws were not loose and resistance was encountered when they were tightened against the locking screw. The licensee determined that these breakers would have tripped and did not identify any operability concerns. One locking screw was missing from a nonsafety-related breaker and the licensee wrote a job request to replace it. The licensee planned to inspect additional breakers on both units. In addition, the licensee planned to enhance training in the areas of breaker inspection to emphasize the verification that the trip arm screw and other fasteners are tight.

The licensee stated that they had never experienced a similar problem with these breakers and the vendor was unaware of any problems of this nature. The inspectors found that previous information notices issued by the NRC did not identify any similar occurrences.

The inspectors concluded that the licensee responded appropriately to the failure of Breaker A-307.

8 FOLLOWUP - ENGINEERING (92903)

(Closed) IFI 368/9406-05: HPSI Rotating Assembly Failure Analysis

On June 24, 1994, the licensee found during surveillance testing that HPSI Pump 2P-89C had developed a large leak from the outboard seal and that the motor had tripped on thermal overload. On July 6, 1994, the licensee disassembled the pump to determine the cause of the outboard seal leak and found a piece of a metal wire resting inside the pump housing. This inspection followup item was opened to evaluate the results of the vendor's analysis to determine the failure mode of the HPSI Pump 2P-89C rotating assembly, the licensee's determination of how the wire entered the system, the reason for the mechanical seal failure, and the licensee's root cause determination for the trip on thermal overload.

CR 2-94-0327 was written to document the deficiencies. The CR was later administratively closed to CR 2-94-0224, which documented that preliminary HPSI flow test data, measured on April 13, 1994, indicated degraded pump flow. Action Item 1 to CR 2-94-0224 required that the pump be disassembled, and sent to the vendor for inspection to determine the cause of the degraded pump flow, why the mechanical seal failed, and why the pump motor tripped on overcurrent. The vendor performed their analysis in December of 1994.

The inspectors reviewed the vendor's analysis and the licensee's root cause evaluation and found that, during a 1983 pump rebuild, the licensee replaced the pump's rotating wear rings but did not replace the stationary wear rings. The licensee was unable to determine why the stationary wear rings were not replaced in 1983. When the licensee reassembled the pump in 1983 and measured the wear ring clearances, they noted that the clearances had exceeded vendor's specifications. The licensee contacted the vendor for guidance on the excessive clearance and the vendor stated that this condition was acceptable. The licensee rebuilt the pump with the excessive clearances.

Between 1983 and 1994, the licensee used the pump under low flow conditions to fill the safety injection tanks (SITs) when SIT levels were low. The decreased SIT levels were the result of HPSI system valve leakages (i.e., SIT relief valves, HPSI injection valves, HPSI discharge check valve). The licensee determined that, during repeated low flow operation of the pump, the rotating wear ring contacted the worn stationary wear ring, thus increasing the amount of contact wear, and clearance, between the wear rings. The vendor analysis also noted that machined grooves on the rotating wear ring wore grooves into the stationary wear ring during pump operation. On June 24, 1994, as the pump was started, the forward thrust of the pump shaft caused the grooves on the wear rings to interlock. The vendor analysis concluded that the interlocked grooves caused the pump to seize, resulting in an overcurrent condition, a pump motor trip on thermal overload, and the mechanical seal failure.

The licensee concluded that low flow pump operation over extended periods eventually increased the wear ring clearance and degraded HPSI pump flow, which eventually rendered the pump inoperable. To limit the number of low pump flow operations by reducing SIT leakages, the leaking HPSI valves were repaired or replaced in Refueling Outage 2R11. The licensee noted that reducing SIT leakages had reduced the use of the HPSI pump for low flow operation. However, the licensee recognized that HPSI pumps were not designed for low flow operation and has proposed the installation of a nonqualified auxiliary pump to function as a means of filling the SITs. This proposal was still being considered.

The licensee concluded that the wire discovered in the pump was not related to the pump failure. They speculated that the wire entered the system during the 1983 pump rebuild when foreign material exclusion was not formalized. Foreign material exclusion procedures have since been formalized to prevent the entrance of foreign material into systems during maintenance.

The inspectors concluded that the licensee's root cause evaluation and their corrective actions were acceptable.

9 REVIEW OF UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors.

- While reviewing the degraded thrust condition of the Unit 2 HPSI header isolation valves (Section 7.1), the inspectors identified that Section 6.3.2.2.4 of the Unit 2 Safety Analysis Report (SAR) stated that the HPSI header valves are utilized as required to obtain balanced flow between headers. However, a plant modification, which began in Refueling Outage 2R10 and was completed in Refueling Outage 2R11, removed the flow balance function of the isolation valves and installed manual throttling valves in each header to balance the flow between the headers.

The licensee informed the inspectors that a licensing document change request had already been initiated to revise the SAR to reflect this plant modification.

The following inconsistency was identified as a result of inspection activities documented in NRC Inspection Report 50-313/96-11; 50-368/96-11.

- Section 12.4 of the Unit 1 SAR and Section 13.4 of the Unit 2 SAR states that a complete description of the licensee's review and audit program is discussed in Section 6.0 of the Units 1 and 2 TSs. However, the licensee had moved the description of these programs to the Quality Assurance Manual Operations.

In response to this inconsistency, the licensee initiated a licensing document change request to revise the SAR to reflect this change.

The licensee informed the inspectors that, as a result of the problems identified at other plants, they had initiated their own review of the Units 1 and 2 SARs to verify that it accurately reflected the way in which the units were operated.

ATTACHMENT 1

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
R. Espolt, Events Analysis Manager
B. Eaton, Unit 2 Plant Manager
C. Fite, IHEA Supervisor
B. Greeson, Acting Unit 2 System Engineering Manager
R. Lane, Director, Design Engineering
C. Little, Unit 2 Design Engineering Coordinator
J. McWilliams, Modifications Manager
D. Mims, Director, Nuclear Safety
M. Ruder, Assessments
T. Russell, Acting Unit 2 Operations Manager
B. Short, Licensing
M. Smith, Licensing Supervisor
L. Waldinger, General Manager, Plant Operations
A. Wrape, Unit 1 System Engineering Manager
C. Zimmerman, Unit 1 Operations Manager

The personnel listed above attended the exit meeting. In addition to these personnel, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

The inspectors conducted an exit meeting on March 6, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

On April 2, 1996, a teleconference was held between T. Reis, Acting Branch Chief, Region IV, NRC, and those members of the licensee staff listed below to recharacterize the NRC enforcement position taken as a result of this inspection.

B. Short, Licensing
A. Wrape, Unit 1 System Engineering Manager
M. Smith, Licensing Supervisor
D. Mims, Director, Nuclear Safety

ATTACHMENT 2

LIST OF ACRONYMS

CEA	control element assembly
CEAC	control element assembly computer
CPC	core protection calculator
CR	condition report
EFIC	emergency feedwater initiation and control
HPSI	high pressure safety injection
I&C	instrumentation and control
IFI	inspection followup item
JO	job order
LER	licensee event report
MDPI	mechanical-driven position indicator
SAR	safety analysis report
SIT	safety injection tank
TS	Technical Specification
UFSAR	updated final safety analysis report
VOTES	valve operation test and evaluation system