ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/95-08
50-368/95-08

Licenses: DPR-51
NPF-6

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

Facility Name: Arkansas Nuclear One (ANO), Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: September 17 through October 28, 1995

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Inspection Summary

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

Results (Units 1 and 2):

Plant Operations

- The operators demonstrated good command and control and clear communication while shutting down the reactor for Refueling Outage 2R11 and while implementing safety system surveillance testing (Section 4.3). The prejob briefings were thorough and comprehensive.

- During reactor coolant system (RCS) draining to reduced inventory, the inspectors observed that the control board operator - reactor (CBOR) did not notice a defective level indicator controller until the indicated reactor coolant system RCS level dropped approximately 14 inches. The

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CBOR continuously monitored RCS level using diverse RCS level indicators. Overall, the RCS draining was well controlled (Section 2.2).

- The inspectors noted that the prejob briefing for the integrated engineered safeguards test (Section 4.2) was risk-based and thorough and that the operators' performance of the test was well coordinated.

- The operators on the refueling bridge did not verify proper refueling mast orientation prior to inserting a fuel assembly into the core, which resulted in breakage of the refueling hoist camera and admittance of foreign material to the reactor vessel. The material was retrieved. A noncited violation was identified (Section 6.3).

Maintenance

- The prejob briefing for the Unit 2 main steam safety valve (MSSV) testing was detailed and comprehensive. The inclusion of site and industry events and lessons-learned related to the testing of MSSVs was a strength (Section 3.3).

- A Technical Specification (TS) violation was identified when the licensee discovered that five MSSVs were set such that they lifted above the TS lift tolerance. The MSSVs were not tested and set under simulated plant operating temperatures and pressures, because the licensee failed to provide the offsite testing lab with information to enable use of environmental conditions similar to the plant's condition (Section 3.3).

- A noncited violation was identified regarding an inadequate pressurizer venting procedure after noble gas vented from the pressurizer actuated the control room emergency ventilation system. The procedure did not provide adequate instructions to contain the noble gas inside the containment building. The licensee developed comprehensive corrective actions to prevent recurrence (Section 6.1).

- Installation of the reactor vessel head was well controlled (Section 6.4).

Engineering

- The licensee was aggressive in pursuing and addressing the cause for the high MSSV lift pressure settings and developed a comprehensive corrective action plan (Section 3.3).

Plant Support

- The inspectors noted good radiological work practices during the following work activities:

(1) Decontamination of service air system (Section 5.1).

(2) Reconstitution of leaking fuel pin (Section 6.2).

(3) Lifting and installation of reactor vessel head (Section 6.4).

Summary of Inspection Findings:

- Two noncited violations were identified (Sections 6.1 and 6.3).
- One violation was identified (Section 3.3).

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On October 14, 1995, at 12:44 a.m., Unit 1 reduced power to 89 percent to perform turbine valve and governor valve testing, returning to 100 percent by 4:21 a.m. Unit 1 remained at 100 percent power until October 23, at 9:11 a.m., when the operators reduced power to 99 percent to isolate a condenser water box leak. Unit 1 returned to 100 percent power by 12 p.m. and remained there for the rest of the inspection period.

1.2 Unit 2

At the beginning of the inspection period Unit 2 was at 98 percent power. On September 18, 1995, the unit began coasting down from 98 percent power in preparation for Refueling Outage 2R11. On September 22, the operators commenced a plant shutdown to begin the refueling outage. The unit remained in the refueling outage 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 Plant Shutdown for Refueling Outage 2R11

On September 22, 1995, the inspectors observed the licensee commence a plant shutdown for Refueling Outage 2R11 in accordance with Procedure 2102.004, Revision 21, "Power Operation." Prior to shutdown, the licensee conducted a thorough pre-evolution brief where the monitoring of plant critical parameters was discussed. The plant parameters included maintaining axial shape index near the equilibrium shape index and ensuring that the power reduction rate was within allowable limits.

Operator command and control was good. The operators consistently used three-part communication and peer checks prior to manipulating controls. The licensee dispatched operators to the plant to verify local indications, valve positions, and equipment response to changing conditions. Radio communication between the control room operators and operators in the plant was distinct and clear. The inspectors observed that the operators repeated all verbal communication.

The inspectors observed the operators remove equipment from service and start equipment at the appropriate power levels in accordance with the procedures. The control room operators knew which annunciators were expected and which were not expected. Unexpected annunciators were appropriately addressed by entering the appropriate annunciator response procedures to determine the reason for the annunciator. So that the operators performing the shutdown could maintain their focus, the shift technical assistant referenced the annunciator corrective action procedure and investigated unexpected annunciators not associated with the shutdown. These unexpected annunciators included control element drive mechanism cabinet trouble and loose parts monitor annunciators.

At 11:38 p.m., the operators manually tripped the reactor by opening the control element assembly trip circuit breakers when the core protection calculators indicated less than 20 percent power. During the posttrip actions, the operators verified the appropriate plant parameters and verbally communicated the parameters to the control room supervisor as required by procedure. The standard posttrip actions did not indicate any plant complications.

2.2 Unit 2 - Draining the RCS to Reduced Inventory

On September 26, 1995, the inspectors observed the licensee drain the RCS to a reduced inventory of 24 inches above the bottom of the hot leg, in order to perform steam generator tube inspections and maintenance on safety injection valves.

The inspectors attended the pre-evolution brief and found it to be risk-based, thorough, and comprehensive. During the brief, the licensee reviewed the procedure with the operators, assigned operator duties, and identified the necessary control room indicators to be monitored during the drain down. The inspectors noted that a discussion regarding the loss of shutdown cooling was the focal point of the brief. The licensee reviewed industry events related to loss of shutdown cooling events at other utilities and "lessons-learned" from past drain down experiences at ANO. The briefing was conducive to open discussion, questions, and comments.

At 12:31 a.m., the operators commenced draining the RCS in accordance with Procedure 2103.011, Revision 21, "Draining the RCS." The procedure required the CBOR to monitor RCS level during the draining evolution. At 12:36 a.m., the RCS draining was stopped at the first level hold point of 286 inches and the CBOR noticed a 14-inch deviation of indicated level between Refueling Level Indicators 2LI-4791 and -4792. Refueling Level Indicator 2LI-4791 displayed 289 inches and Refueling Level Indicator 2LI-4792 displayed 303 inches. Because the CBOR did not identify the deviation early in the draining evolution, the shift supervisor counselled the CBOR on the importance of monitoring all level indicators while draining the RCS. Additionally, the inspectors questioned the operator on why he had missed identifying the deviation during the RCS draining. The CBOR stated that he had focused on monitoring Pressurizer Level Indicators 2LI-4627-1 and -2, rather than monitoring the refueling level indicators, and noticed Refueling Level Indicator 2LI-4792 was locked up when the RCS draining was halted at the first RCS level hold point.

Upon realizing two level indicators did not agree, the CBOR concluded that the level indicator controller needed to be reset. After resetting the controller, the inspectors noted that level appeared to be oscillating on Refueling Level Indicator 2LI-4791, but not so on Refueling Level Indicator 2LI-4792. As a result, the inspectors questioned the licensee as to whether the indicator was still locked up. In response to the inspectors' question, the licensee performed further investigation and determined that the digital controller was defective. The licensee replaced the controller prior to recommencing the RCS drain down evolution. After the defective controller was replaced, the independent instruments indicated the same level. The draining of the RCS was completed without difficulty later that day.

The inspectors determined that at all times during the draining evolution, the CBOR had a diverse means of monitoring RCS level by reading Pressurizer Level Indicators 2LI-4627-1 and -2. Additionally, the inspectors concluded that a relatively small quantity of water (approximately 500 gallons of RCS over a 5-minute period) was drained before the defective controller was noticed. The inspectors concluded that the observation was of minimal safety significance and that the remainder of the RCS draining evolution was well controlled.

3 MAINTENANCE OBSERVATIONS (62703)

3.1 Units 1 and 2 - Maintenance Observations

During this inspection, the inspectors observed and 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:

- Job Order (JO) 00939476, "Repair of E1B Level Controller LC-3025," performed on October 11, 1995.
- JO 00939226, "Repair of Service Water Pump P-4B Motor Operated Disconnect (MOD)," on October 10.
- JO 00931201. "Unit 2 MSSV Maintenance," Revision 8, performed on October 17.

- JO 00932535, "Replace Low Pressure Safety Injection Valve 2CV-5037," performed on October 12.

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 <u>Unit 1 - Repair of Service Water Pump P-4B MOD (JO 00939226)</u>

On October 10, 1995, the inspector observed portions of the repair to the porcelain links in the Service Water Pump P-4B MOD. Service Water Pump P-4B can be powered from either vital train, and the MOD provides electrical separation between the electrical trains. The porcelain links are connected to the operating mechanism in the MOD, preventing the electrical phases from shorting to ground. The porcelain links have metal inserts going partially into the link, which allow for adjustments of the operating mechanism.

During a tour, an operator noticed that one porcelain link was damaged, initiated Condition Report 1-95-0593, and wrote Job Request 091339 to replace the porcelain link. The inspectors observed portions of the corrective maintenance to replace the damaged link. The licensee found that part of the metal insert was loose and had cracked the porcelain during movement of the operating mechanism. The system engineer found that the adjusting nut in the metal inserts did not have a torque value specified. The licensee inspected all similar links in other MODs in both units and found four other porcelain links loose. The system engineer determined that no torque value had been specified by the vendor. Accordingly, the system engineer determined a torque value for metal inserts and adjusting nuts, incorporated these values into work instructions, and then verified that all the porcelain links were satisfactory.

The inspectors concluded that the licensee's root cause for the cracked porcelain and the repair of the MOD was satisfactory.

3.3 <u>Unit 2 - MSSV Lift Points Out of Tolerance</u>

3.3.1 Description of Event

The licensee planned to test three of the Unit 2 MSSVs in accordance with Procedure 2306.006, "Unit 2 MSSV Test," prior to the start of Refueling Outage 2R11. On September 21, 1995, the inspectors attended the prejob briefing for the testing of these valves. The brief, which was attended by all personnel involved in the conduct of the test, included a discussion of the procedural steps, assigned duties, precautions and limitations, communications, radiation protection, and stay times resulting from high area temperatures. Contingency actions in the event of a turbine trip or a stuck open safety valve were also discussed. The termination criteria for the test were clearly defined during the briefing. The brief also included a thorough review and discussion of industry events related to MSSV testing and a discussion of past problems experienced during Unit 1 safety valve testing.

The inspectors observed as the licensee installed test gauges and prepared to install the valve testing device. The licensee found that it could not raise main steam header pressure above the minimum pressure called for in the test prerequisite, 840 pounds per square inch gage (psig), and delayed the start of the test to evaluate revising the procedure to change the minimum pressure at which the test could be performed.

On September 22, 1995, the licensee changed the procedure to utilize a lower test pressure of 820 psig and performed MSSV pressure lift point testing in accordance with Procedure 2306.006, "Unit 2 MSSV Test." The licensee measured the valve body temperature to verify that the valves were thermally stable, verified steam header pressure, and used the hydroset test rig to simulate a lift pressure to lift MSSV 2PSV-1052 as required by procedure. During the test, the licensee found that the valve failed to lift at 6.12 percent (1144.0 psig) above the nominal lift pressure of 1078 psig. The TS acceptance criteria range was +3 percent (1110.3 psig) and -1 percent (1067.2 psig). The licensee initiated Condition Report 2-95-0294 to document failure of MSSV 2PSV-1052.

On September 23, the licensee continued additional testing of MSSVs 2PSV-1002 and 2PSV-1006. The licensee found that the MSSV 2PSV-1002 lifted at a simulated pressure of 4.27 percent (1124 psig) above the nominal setpoint of 1078 psig and that MSSV 2PSV-1006 failed to lift at a simulated pressure 5.92 percent (1199 psig) above the nominal setpoint of 1132 psig. Because of the unusual number of MSSVs with lift settings outside of tolerance, the licensee stopped the test, cooled down the plant to begin Refueling Outage 2R11, and wrote Condition Report 2-95-0294 to document the condition.

After the plant cooled down, the licensee removed all 10 (five on each main steam header) MSSVs and sent the valves to Wyle Laboratories for testing and/or refurbishment. Representatives from ANO also went to Wyle Laboratories to observe the testing. On September 30, Wyle Laboratories lab technicians placed MSSV 2PSV-1006 on a test steam header and raised valve inlet pressure to 90 percent (1018 psig) of the nominal setpoint pressure. A lab technician placed insulation blankets and an environmental box around the valve to thermally stabilize it to an ambient temperature of 140°F. Wyle Laboratories considered a valve to be thermally stabilized when the valve body temperature did not change more than 5°F within 5 minutes, and the valve neck inlet temperature was maintained within 200°F of the steam inlet temperature. When the valve reached thermal stability, the technicians raised the steam header test pressure and found that the valve lifted at 0.97 percent (1143 psig) above nominal pressure of 1132 psig, which significantly differed from its lift point when tested in the plant.

The licensee noted significant valve body temperature differences between the tests conducted at the plant and at Wyle Laboratories and assumed valve body temperature had an impact on MSSV 2PSV-1006 lift pressure. This assumption was confirmed by simulating plant temperature conditions and retesting the valve at Wyle Laboratories. The valve lifted at 5.65 percent (1196 psig) above the nominal lift pressure under the simulated service conditions.

Changes were made to the Wyle Laboratories test procedure to simulate the plant's environmental conditions for testing the remaining MSSVs. The changes included: (1) thermally stabilizing the valve at 80 percent of nominal set pressure instead of 90 percent nominal set pressure, (2) reducing ambient temperature from 140°F to 110°F, (3) excluding the use of insulating blankets around the valve, and (4) eliminating the requirement that the inlet neck temperature be within 200°F of steam inlet temperature. Between October 2 and 9, the technicians conducted tests using the revised procedure on the remaining MSSVs and found four additional MSSVs failed to meet TS required lift pressure tolerances. Again, the valves lifted above the setpoint. The licensee conducted a past operability assessment for the acceptable and unacceptable MSSV lift pressure points for the following conditions: loss of condenser vacuum, a feedwater line break, and a small break loss of coolant accident. The licensee determined that the MSSV setpoints had sufficient relief capacity available to ensure primary and secondary pressure design limits were maintained and that the emergency core cooling performance criteria remained unaffected for these events. The licensee did not take credit in these evaluations for those valves that did not lift during testing.

3.3.2 Root Cause

The licensee reviewed all lift point deviations since 1989 to determine a root cause for the high lift points. Based on this data review, the licensee found that it did not provide environmental criteria for testing MSSVs sent to the lab. Environmental criteria included specifying ambient temperature for the valve, temperature and conditions of the steam, and thermal profiles of the valves. The licensee found that the environmental criteria was critical when pressure setting the MSSVs in that the temperature either expanded or contracted the metal spring, which subsequently impacted the MSSV lift setpoint. MSSVs tested in the plant were tested under actual plant conditions. Without specific plant environmental conditions provided by the licensee, the lab technicians could have tested and set the MSSVs under different a environmental condition, which would result in different lift pressures. The licensee concluded that the high lift points were caused by not ensuring that the same environmental conditions existed in the lab as in the plant for testing of the MSSVs.

A review of past condition reports documenting MSSV lift pressures outside the acceptable tolerances was performed, and the licensee found five condition reports between 1989 and 1994 that noted this deficient condition. The licensee concluded that the corrective actions for these five condition reports and responses were ineffective, because environmental effects on MSSV lift pressures were not considered during MSSV testing. The past corrective actions included: (1) establishing an MSSV training program, (2) revising the testing procedure to notify engineering when lift points were outside tolerance, (3) expanding TS acceptance criteria, (4) evaluating corrective actions for out-of-tolerance MSSVs experienced at other utilities, (5) reviewing vendor technical manual requirements for testing the MSSVs, and (6) adjusting the valves' setpoints. These condition reports dispositioned the out of tolerance MSSV as a recurring problem in the industry due to MSSVs being large and imprecise. The licensee found that these expectations were a contributing cause to the ineffective corrective actions.

In addition, the licensee had prior opportunities from industry information to identify environmental effects on MSSV lift points, including: (1) AEOD/E90-09, "Additional Factors Affecting the Lift Point of Pressurizer Safety Valves," (2) Information Notice (IN) 91-74 "Changes in Pressurizer Safety Valve Lift Points Before Installation," (3) IN 93-02 "Malfunction of a Pressurizer Code Safety Valve," (4) IN 94-56 "Inaccuracy of Safety Valve Set Pressure Determinations Using Assist Devices," and (5) IN 89-90 "Pressurizer Safety Valve Lift Point Shift." While the particular details of the industry information were not directly applicable to ANO, the content of this information was relevant to testing and setting of MSSVs.

The licensee found that they had not been testing the MSSVs in accordance with TS 3.7.1.1, Table 3.7-5. A note on Table 3.7-5 required that MSSV lift setting pressure correspond to ambient conditions of the valve at normal operating pressure and temperature. The licensee also found that the valves were not tested in accordance with American Society of Mechanical Engineers (ASME) Operation and Maintenance OM-1 Code, Section 8.1.1.5, which required that ambient operating condition of the valve be simulated during testing.

3.3.3 Corrective Actions

As a result of the event, the licensee proposed and performed the following corrective actions:

- The MSSVs were retested and set under estimated environmental conditions at the lab before being installed on the plant's mainsteam header.

- During power escalation, the licensee will measure the actual ambient environmental conditions of the MSSVs when the plant is in hot standby and again at 80 percent power. If actual ambient conditions are different than the estimated ambient conditions used at Wyle Laboratories, the licensee will perform actual lift point verification.

- The licensee will mark specific locations on the MSSV bodies on which to place the temperature probe so that temperature measurements for future valve body temperature readings will be consistent.

- A test plan will be developed to pressure lift test the MSSVs during plant operation under various temperature conditions.

- The licensee proposed continuing to pursue a change to the TS lift point tolerance to ±3 percent.

- ASME Operating and Maintenance OM-1 Code and TS requirements will be implemented for ASME code Class 1, 2, and 3 and inservice test safety-relief valves in test procedures for Units 1 and 2.

- A specific test procedure for testing ANO MSSVs at Wyle Laboratories will be developed. This test procedure will ensure consistency between the environmental conditions at Wyle Laboratories and the plant.

- The licensee planned to establish a trending or monitoring program for MSSVs and pressurizer safety valves. The licensee will also review and determine if a trending program is needed for other safety-relief valves.

3.3.4 Conclusions

The inspectors reviewed the root cause analysis report, Procedure 2306.006, the TS, and the corrective actions. The inspectors confirmed that the licensee was in violation of TS 3.7.1.1 in that they failed to adequately test and adjust MSSVs at the ambient, normal operating pressure and temperature as required by the TS (368/9508-01). The licensee was aggressive in pursuing and addressing the cause for the high lift pressure settings. In addition, the licensee was self-critical in their evaluation of missed opportunities to adequately address MSSV setpoints being out of tolerance. The inspectors determined that the proposed corrective actions were thorough and comprehensive to prevent recurrence.

3.4 <u>Unit 2 - Removal of Low Pressure Safety Injection (LPSI) Valve 2CV-5037 (JO 00932535)</u>

On October 12, 1995, the inspectors observed the licensee remove LPSI Valve 2CV-5037 in accordance with Controlled Work Package 90-2015/932535-01. During the maintenance task, the inspectors made the following observations:

- The inspectors noted that the system engineer was present at the job site to monitor work activities.

- A health physics technician was also present and provided good support of the work activities. He collected air samples while the LPSI valve was being cut and periodically monitored the area for radiation doses. He advised the workers of the dose rates in the area to maintain low personnel exposure.

- The worker who performed the LPSI valve cut was meticulous in preparing his work area prior to performing the cut. He attached a catch basin below the valve to catch the potentially contaminated water trapped in the piping and verified that the catch basin drainage hose was not kinked or blocked prior to performing the cut. However, the inspectors noted that, while cutting the pipe, the worker did not anticipate that metal chips produced from the cut would fall into the catch basin and clog the catch basin drain. The worker used a tool to unclog the drain and prevent spilling of contaminated water onto the floor.

- The required ignition source permit was complete and fire watch controls were in place.

Based on the above observations, the inspectors concluded that this maintenance task was performed well and in accordance with procedures.

4 SURVEILLANCE OBSERVATIONS (61726)

4.1 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:

- Procedure 1304.037, "Unit 1 Reactor Protection System Channel A Test," on October 11, 1995.
- Procedure 2305.001, Revision 12, "Integrated ESF Test" on October 16.
- Procedure 1104.036, Revision 35, "Emergency Diesel Generator Operation," Supplement 1, "DG 1 Monthly Test," on October 18.
- Procedure 1104.005, Revision 34, "Reactor Building Spray System Operation," Supplement 3, "RB Spray Pump P-35A Quarterly Test," on October 19.
- Procedure 2409.499, "HPSI System Flow Balancing," Revision 0, on October 24 and 25.
- Procedure 2305.037, "HPSI Motor Operated Valve (MOV) Differential Pressure Tests," Revision 0, on October 24 and 25.
- Procedure 2104.039, "Full Flow HPSI Test," Revision 35, on October 24 and 25.

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

4.2 Unit 2 - Integrated Engineered Safety Features (ESF) Testing

On October 16, 1995, the licensee performed the 18-month integrated ESF testing in accordance with Procedure 2305.001, Revision 12, "Integrated ESF Test." The licensee conducted a thorough prejob brief which included defining operator responsibilities. During the brief, the licensee explained that shutdown cooling would momentarily be secured during performance of the test to prevent the inadvertent loss of a pump. The licensee stressed minimizing the amount of time shutdown cooling was secured and described the necessary operator actions in the event that shutdown could not be restored.

During the performance of the test, the inspectors noted that the licensee used excellent three-part communication. The test was performed without significant operator problems. All ESF equipment operated within the required response time acceptance criteria, except for Service Water Intake Structure Fan 2VEF-25B, which automatically started too soon due to a defective motor time-delay relay. The licensee initiated a condition report to document the problem, replaced the relay, and retested. The inspectors concluded that performance of the integrated ESF test was well coordinated.

4.3 Unit 2 - Testing of the Safety Injection Pumps and Injection Valves

On October 24 and 25, 1995, the inspectors witnessed the licensee's implementation of the following surveillances from the Unit 2 control room:

- Procedure 2409.499, "HPSI System Flow Balancing," Revision 0,
- Procedure 2305.037, "HPSI MOV Differential Pressure Tests," Revision 0, and
- Procedure 2104.039, "Full Flow HPSI Test," Revision 35.

The three above-listed procedures were performed sequentially by the same control room crew. Procedure 2409.499 was performed to balance the flow in the four injection legs of high pressure safety injection (HPSI) Headers B and D following installation during this outage of new manual throttle valves per Design Change Package 94-2002. Procedure 2305.037 was then performed to demonstrate the capability of the HPSI motor-operated valves (MOVs) to operate against design differential pressure per NRC Generic Letter 89-10, "Safety-Related MOV Testing and Surveillance - 10 CFR 50.54(f)." Procedure 2104.039 was performed as a full flow test of the HPSI system to satisfy ASME Section XI; Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs;" and TS 4.5.2.h.

The prejob briefings were attended by the operations manager, MOV maintenance engineers, system engineers, design engineers, and startup engineers. The inspectors found the prejob briefing to be thorough and open for discussion to the attendees. During the test, the following weaknesses in the procedures were disclosed.

- Procedure 2104.039 lacked specific steps for handling changes in RCS level during certain valve and pump alignments (although precautions concerning RCS level changes were provided up front in the procedure).

- There was inadequate space on data sheets (or no additional sheets provided) to record data when performing all sections of Procedure 2104.039.

- Recording parameters in Procedure 2305.037 were not useful under certain system alignments (such as recording refueling water tank temperature when RCS temperature would be more appropriate, since the HPSI was taking suction on the RCS not the refueling water tank).

The licensee noted the weaknesses and planned to improve the procedure by initiating a procedure improvement form.

While performing the test, the inspector noted that the control room operators exhibited good command and control of the test evolution and observed that the licensee consistently used three-part communication. Despite the weaknesses in the procedures, the licensee's performance of the surveillance was considered by the inspectors to be good.

5 PLANT SUPPORT ACTIVITIES (71750)

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

5.1 Unit 1 - Service Air System Decontamination

The inspector observed portions of the licensee's continuing efforts to decontaminate the service air system (see NRC Inspection Report 50-313/95-07; 50-368/95-07). The licensee flushed service air lines with water to remove contamination until no detectable contamination was found. The inspector observed that the licensee used good radiological work practices while flushing these lines. The licensee followed Procedure 1409.580, "Service Air Decontamination," when flushing the system.

6 REFUELING ACTIVITIES (60710)

6.1 Unit 2 - Venting of Pressurizer Actuates Control Room Emergency Ventilation System

6.1.1 Description of Event

On September 26, 1995, 4 days after the plant was shut down for Refueling Outage 2R11, the operators began to fill and cool down the pressurizer in accordance with Procedure 2103.011, "Draining the Reactor Coolant System," in preparation for draining the RCS to reduced inventory. The licensee drained the RCS to perform maintenance on plant equipment and to perform steam generator tube inspections. On September 24, 1995, the licensee purged the containment building atmosphere of radioactive gas, defeated the personnel hatch interlocks, opened the personnel hatch inner and outer doors, and opened the equipment hatch to permit personnel access to the containment building.

Ventilation was provided by Containment Building Ventilation Exhaust Fan 2VEF-15, which removed the air from the containment building and drew air from the outside environment through the equipment hatch. Air exhausted from the containment building was monitored for radioactivity using Containment Exhaust Ventilation Process Monitor 2RE-8233.

To collapse the pressurizer steam bubble, Section 7 of the procedure required that the pressurizer be filled and that the radioactive noble gas be removed from the pressurizer by venting to the quench tank. The quench tank would then be vented to the containment sump, which was located on the bottom of the containment building. At 2:54 a.m., after pressurizer pressure decreased to the required pressure for collapsing the bubble, the operators aligned the pressurizer vent to the quench tank, which was aligned to the containment sump.

Since the auxiliary building was maintained at a lower pressure than the containment building, the airflow also carried the noble gas through the personnel hatch, located inside the upper south electrical penetration room (USEPR), and through open Fire Door FD-297 into the auxiliary building hallway. At approximately 3:10 a.m., the operators observed that Containment Building Exhaust Process Monitor 2RE-8233 indicated an increase in activity levels from 100 counts per minute (cpm) to 160 cpm. Additionally, three RM-14 friskers, located (1) outside the personnel hatch in the USEPR, (2) in the dressout room located in the auxiliary building hallway, and (3) near the entrance to the radiologically controlled area at the end of the hallway, began to alarm.

At approximately 3:16 a.m., the control room emergency ventilation system started when Control Room Supply Ventilation Process Monitor 2RE-8750-1 detected radiation levels to approximately 300 and 400 cpm, which were above the monitor's actuation setpoint. Control Room Supply Ventilation Monitor 2RE-8750-1 is mounted on the bottom of the unit supply ventilation duct and is located in the ceiling above the health physics office, which is just outside the entrance of the radiologically controlled area.

At 3:20 a.m., in response to the alarming RM-14 friskers, health physics (HP) technicians gathered 10-minute air samples in the USEPR and found concentrations of noble gas present. The HP technicians then closed the outer door to the personnel hatch at 3:22 a.m. to prevent further release of noble gas through the hatch. After the door was closed, Control Room Supply Ventilation Process Monitor 2RE-8750-1 showed radiation levels decreasing. The operators started Penetration Room Exhaust Fan 2VEF-38 to remove the noble gas from the USEPR.

At 3:29 a.m., the licensee attempted to reopen the outer door of the personnel escape hatch but was unable to do so due to a missing door pin. When repaired, the door was opened and noble gas again flowed from the personnel hatch entrance. Control Room Supply Ventilation Monitor 2RE-8750-1 indicated a radiation level increase from 160 cpm to approximately 400 cpm while the normal control room ventilation remained isolated. As a result of the increased radiation level, HP technicians reclosed the outer door to the personnel hatch and access to the USEPR was denied until noble gas levels in the room decreased. At 3:29 a.m., the operators suspended the pressurizer filling and venting evolution.

6.1.2 Root Cause Determination

On September 27, 1995, system engineers conducted smoke tests with the auxiliary building and the containment building ventilation systems aligned identically to that during the pressurizer venting evolution in order to determine auxiliary building airflow direction. The smoke tests confirmed strong airflow through Fire Door FD-297, down the auxiliary building hallway, and through the entrance of the radiologically controlled area turnstiles with a slight flow into the HP office.

The licensee initiated Condition Report C-95-0181 to document the event and to perform a root cause determination. Based on the smoke tests, the licensee's root cause evaluation concluded that noble gas was transported to the auxiliary building because the airflow produced by the containment and auxiliary building ventilation system alignments were not fully considered prior to the venting of the pressurizer.

The licensee found that the Unit 2 Safety Analysis Report indicated that airflow would be directed from areas of lesser contamination to areas of greater contamination. The licensee determined that, to meet this criterion, air transport from the containment building to the auxiliary building should be restricted when airborne activity in the containment is elevated and the auxiliary building should be at a pressure greater than containment building pressure. These guidelines were not met while the pressurizer was being vented.

A transport of noble gases through the personnel hatch had not occurred in previous outages, because the personnel hatch inner and outer doors were interlocked during previous venting evolutions. The licensee performed comprehensive upgrades prior to Refueling Outage 2R-11 to allow the personnel hatch interlocks to be defeated and the doors to open for more efficient access to the containment building. Since the licensee did not experience noble gas transport in previous venting evolutions, the licensee did not consider containment and auxiliary building ventilation alignments to prevent noble gas transport to the auxiliary building after the upgrades were completed.

The licensee reviewed Control Room Supply Ventilation Monitor 2RE-8750-1 printouts to determine if the monitor actuated as a result of noble gas being present in the ventilation supply duct. Control Room Supply Ventilation Monitor 2RE-8750-1 is mounted on the outside of the duct. The printouts indicated that elevated activity levels corresponded to opening and closing of the personnel hatch outer door at 3:22 and 3:29 a.m. The licensee stated that the control room operators were not exposed to the noble gas because noble gases were external to the control room ventilation ducting. The detector response was not characteristic of airborne activity being circulated through the control room ventilation supply. The inspectors reviewed the detector printouts and determined that the licensee's conclusion was valid.

6.1.3 Corrective Actions

In response to the event, the licensee proposed the following corrective action plan:

- The licensee revised Procedure 2103.011 to verify that the containment interlocks were activated so that the personnel hatch doors remained closed while collapsing the pressurizer bubble.

- The licensee reviewed evolutions which had the potential for increasing airborne levels in containment and modified associated procedures to verify personnel hatch interlocks were activated prior to performing these evolutions.

- The licensee will evaluate the impact of performing maintenance on primary equipment which may cause an increase of airborne activity inside containment. From the evaluation, the licensee will determine additional controls to limit activity levels inside the containment building. The licensee stated that this action item includes sampling of the fluid prior to venting the primary equipment.

- As a long-term action, the licensee will review and evaluate the event for applicability to Unit 1. In addition, the licensee will incorporate the event into "lessons-learned" training for both units.

6.1.4 Inspection Findings

The inspectors reviewed the root cause analysis, conducted interviews, reviewed Procedure 2103.011, and confirmed the licensee's findings. As a result of this event, the inspectors' concerns included an unmonitored release to the environment and the potential to inadvertently expose personnel to high activity levels. The inspectors reviewed the chart recorder printout for the auxiliary building ventilation process monitor and found that the noble gas discharge to the outside environment through the auxiliary building ventilation system was monitored. The inspectors found that the licensee did not sample the pressurizer steam space to determine if the noble gas activity level was within acceptable limits prior to venting. The inspectors reviewed the air activity daily running log and confirmed that noble gas activity exposure to personnel was low.

The inspectors concluded that Procedure 2103.011 was a violation of TS 6.8.1.a in that it did not provide adequate instructions for venting the pressurizer. However, the licensee determined that the exposure to personnel in the auxiliary building was less than 0.1 percent derived air concentration equivalent iodine, which was less than the 30 percent evaluated derived air concentration required for posting an area. The inspectors did not consider this exposure level to be safety significant. The licensee searched the condition report data base and could not find any previous occurrences identical to this event. The inspectors reviewed the licensee's corrective actions and concluded that the actions were adequate to address their concerns. This self-disclosing and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

6.2 Unit 2 - Reconstitution of a Leaking Fuel Pin

On October 6, 1995, the inspectors observed the licensee reconstitute a leaking fuel pin in accordance with Procedure 2302.049, "ANO-2 Fuel Assembly Reconstitution," Revision 3. The leaking fuel pin was identified by removing the fuel assembly, which contained approximately 200 fuel pins, from the core, placing fuel assembly in the spent fuel pool, and performing an ultrasonic test on the fuel pins. The licensee determined that the fuel pin leaked because a tab on a grid strap wore a hole through the fuel pin as the fuel pin vibrated during plant operation. Reconstitution required removing and replacing the leaking fuel pin with a stainless steel pin, placing the defective fuel pin in an encapsulation tube, and storing the tube in the spent fuel pool.

During the evolution, the inspectors verified that the licensee and the contractors used calibrated equipment, maintained foreign material exclusion around the spent fuel pool, appropriately implemented quality control checks, and used good radiological work practices. The inspectors noted that the reactor engineering manager and the reactor engineer were present to observe the contractors perform the reconstitution activity. The inspectors concluded that the licensee's performance of the evolution was good.

6.3 Unit 2 - Broken Refueling Hoist Camera During Refueling Activities

On October 10, 1995, the licensee began moving fuel from the spent fuel pool into the core in accordance with Procedure 2502.001, Revision 26, "Refueling Shuffle." The procedure required that communication be established between a communicator in the control room and personnel on the refueling bridge. The communicator specified the fuel shuffle sequence, which provided the core locations for inserting the fuel and the refueling mast orientation, to the refueling machine operator. The refueling mast orientation ensured that the camera attached to the refueling hoist was oriented properly to prevent the camera from contacting the core shroud. The camera was used as an aid for the operator to monitor the insertion of the fuel assembly into the core.

The licensee placed the first fuel assembly in Core Location A-10 and began to lower the second fuel assembly into Core Location R-10 (directly across the core from A-10), when the refueling hoist camera contacted the core shroud, breaking the plexiglass camera cover. The broken plexiglass camera pieces fell into the reactor vessel. Fuel movement was stopped and the second fuel assembly was moved to an inspection rack. The fuel assembly was visually inspected and no damage was found. The licensee used a vacuum to remove the broken camera cover pieces and visually inspected the reactor vessel internals for additional broken pieces.

The licensee interviewed the individuals involved in the event and found that the root cause of the event was a breakdown in communication between the control room communicator and the refueling bridge personnel. The communicator failed to provide the mast orientation to the refueling machine operator prior to his attempt to place the second fuel assembly in Core Location R-10. The communicator was aware of the requirement to provide the mast orientation, but was not aware that is was critical to prevent camera contact with the core shroud. The communicator had previously performed refueling on Unit 1 where mast orientation was not critical to preventing camera-shroud contact. The licensee concluded that a contributing factor was inattention to detail by personnel on the refueling bridge. Although refueling bridge personnel were aware of the requirement to rotate the mast, they failed to do so, because their attention was directed to moving the second fuel assembly.

Before recommencing refueling activities, night orders were written to stress the importance in communicating the mast orientation during fuel shuffle. The night orders required that the senior reactor operator in charge of refueling verify proper mast orientation and that a copy of Procedure 2502.001 be kept on the refueling bridge for such verification. The night orders were briefed to all oncoming control room crews and refueling personnel.

The inspectors reviewed the procedure and interviewed the individuals involved in the refueling evolution. The inspectors found that the personnel on the refueling bridge and in the control room each had a copy of Procedure 2502.001, but they did not refer to the procedure to verify mast orientation before the second fuel assembly was inserted. Attachment E, "ANO-2 Allowable Refueling Machine Mast Orientations," of the procedure provided a grid block layout of the core with the required mast orientation for each grid block near the core shroud. The procedure required that Core Location R-10 mast orientation be 270 degrees and Core Location A-10 mast orientation be 90 degrees. The inspectors learned that the refueling mast was oriented 90 degrees for placing the first fuel assembly, but was not reoriented to 270 degrees prior to lowering fuel into Core Location R-10. The refueling machine operator did not reorient the mast before inserting the fuel assembly in Core Location R-10 because he relied upon the communicator to provide the mast orientation for each assembly.

The licensee's process for inserting the fuel assemblies into the core locations included the communicator verbally providing mast orientation. This responsibility was discussed during the test and evolution brief before fuel movement commenced. The inspectors found that the communicator performed refueling on Unit 1 and defueling Unit 2 and should have been aware that mast orientation near the core shroud was critical. In addition, Step 6.10.1 of Procedure 2502.001 required that the communicator refer to Attachment E for mast orientation before the second fuel assembly was lowered into Core

Location R-10. The licensee identified and the inspector concluded that personnel failed to follow the procedure in that the communicator did not refer to Attachment E and did not communicate the mast orientation listed in the fuel shuffle sequence. This is a violation of TS 6.8.1.a.

The inspectors considered that the failure to follow procedure was a human error and of minor safety significance. The licensee took prompt and immediate corrective action by removing the fuel assembly and verifying that the assembly was not damaged as a result of the camera contacting the core shroud. The inspectors concluded that the immediate corrective actions were sufficient to prevent recurrence. This licensee identified violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

6.4 Unit 2 - Lifting and Installation of Reactor Vessel Head (JO 00933626)

On October 16, 1995, the licensee conducted a prejob brief to discuss activities related to reinstalling the reactor vessel head using the containment building polar crane. The HP supervisor reviewed the radiological requirements for the head lift with the individuals involved. In that review, the HP supervisor stressed that the head lift could create a potential for changing radiological conditions and that HP technicians would be stationed around the head lift path to monitor these changing conditions. He reminded the individuals that the HP technicians had authority to tell individuals to move from the area if it was determined that the dose rates were excessive.

On October 17, the licensee lifted the head from the head stand and installed the head on the reactor vessel in accordance with Procedure 2504.005, Revision 8, "Reactor Vessel Closure Head Removal." During the lift, the inspectors observed that HP coverage was good and met the expectations discussed in the prejob briefing. Further, the inspectors noted that the coordination and control of the head lift evolution was good.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

C. Anderson, Unit 2 Operations Manager
R. Beaird, Unit 2 Maintenance
B. Eaton, Unit 2 Plant Manager
D. Fowler, Quality Assurance Supervisor
J. Kowalewski, Unit 1 Electrical Superintendent
R. Lane, Design Engineering Director
D. McKinney, Unit 2 Assistant Operations Manager
D. Mims, Licensing Director
T. Mitchell, Unit 2 System Manager
B. Short, Licensing Specialist
M. Smith, Licensing Supervisor
J. Veglia, Startup Supervisor
L. Waldinger, Plant Operations General 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 November 1, 1995. 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 inspection report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.