ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/95-07
50-368/95-07

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: August 6 through September 16, 1995

Inspectors: K. Kennedy, Senior Resident Inspector
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Approved: Terrence Reis 10-24-95
T. Reis, Acting Chief, Project Branch C Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced inspection of onsite review of events, operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, followup - plant support, and review of a licensee event report (LER).

Results (Units 1 and 2):

Plant Operations

- A painter inadvertently stepped on and opened a main feedwater flow transmitter flush line valve, resulting in a Unit 2 reactor trip on September 1, 1995. A missing cap on the main feedwater flow transmitter flush line and an inadequate prejob walkdown to identify and flag trip sensitive equipment contributed to the trip (Section 2.1).

- Weaknesses in command and control, use of procedures, and operator performance led to a Unit 2 reactor trip on September 2 during a reactor startup following the reactor trip on the previous day. The failure to maintain axial shape index (ASI) below the reactor trip setpoint prior

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to exceeding 17 percent calculated average raw excore power, as required by the startup procedure, was determined to be a violation of Technical Specification (TS) 6.8.1. The licensee's root cause evaluation was self-critical and thorough. In addition, the licensee's proposed corrective actions appeared to be comprehensive (Section 2.2).

- In attempting to free an obstruction in a resin transfer line, a Unit 2 waste control operator performed system lineups and manipulations which were not described in a licensee procedure, resulting in extensive radiological contamination of the Unit 1 service air system. This failure to follow procedure was identified as a second example of a violation of TS 6.8.1 (Section 2.4).

- Operations failed to anticipate the need for emergency boration of Unit 2 upon a reactor trip for late-in-cycle core conditions, in order to maintain the TS required shutdown margin.

Maintenance

- Maintenance and surveillance activities continued to be performed well. Personnel took the appropriate actions when a procedural error was discovered and the inspectors observed that system engineers were involved in maintenance and surveillance activities (Sections 4 and 5).

- A painter stepped on a reactor plant valve causing the valve to change position. His inadvertent actions resulted in a reactor trip.

Engineering

- The licensee's engineering staff was actively involved in the day-to-day operation of the plant and in resolving emergent problems. System engineers provided good support in the efforts to resolve the contamination of the Unit 1 service air system and were involved in routine equipment maintenance activities (Sections 2.4, 4.2, and 6).

Plant Support

- The licensee's identification of and response to the contamination of the service air system was good. Unit 1 operators quickly identified the source of the contamination and personnel sampled connected systems to determine the extent of the contamination. Although the licensee did not initially have formal instructions for the decontamination activities, they incorporated their plans into temporary instructions which were thorough and comprehensive. As described in NRC Inspection Report 50-313/95-21; 50-368/95-21, the licensee's system recovery process was well planned with adequate management attention and oversight (Section 2.4).

- Normal and emergency lighting in the Unit 1 main steam isolation valve (MSIV) room was satisfactory. Normal lighting in the Unit 2 MSIV room was poor, but sufficient to conduct routine operations expected to be performed in the room. Emergency lighting appeared to be adequate to perform local operator actions performed in the event of a shutdown conducted from outside of the control room (Section 8).

Summary of Inspection Findings:

New Items

- Violation 313/9507-01 (Sections 2.4)

Closed Items

- LER 313/95-009 (Section 9)
- Noncited Violation 313/9507-02 (Section 2.2)

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power and, except for two planned power reductions to approximately 90 percent power for main turbine and governor valve testing, remained at 100 percent for the entire inspection period.

1.2 Unit 2

Unit 2 began the inspection period at 98 percent power. On August 12, 1995, operators reduced reactor power to approximately 55 percent to repair tube leaks on Feedwater Heater 2E-6B. Power was returned to 98 percent on August 14. On September 1, an automatic reactor trip occurred after a painter inadvertently bumped and opened a flow orifice flush valve on a feedwater flow transmitter, which resulted in an increase in feedwater flow and a high steam generator level in Steam Generator B, which generated the reactor trip signal. During the subsequent plant startup on September 2, an automatic reactor trip occurred from approximately 17 percent power due to ASI being outside the trip setpoint of plus or minus 0.5 when the auxiliary reactor trip was enabled at 17 percent raw neutron flux average power. The licensee restarted the reactor on September 3 and returned the plant to 98 percent power on September 5, where it remained throughout the inspection period.

2 ONSITE REVIEW OF EVENTS (93702)

2.1 Unit 2 - Reactor Trip Due to Inadvertent Opening of Feedwater Flow Transmitter FT-1129 Flush and Drain Valve

On September 1, 1995, with the plant at 98 percent reactor power, an automatic reactor trip occurred due to high steam generator water level in Steam Generator B. Just prior to the trip, operators observed fluctuations in the speed of Main Feedwater Pump B and resulting changes in feedwater flow. Before operators could take manual control of the feedwater control system, the water level in the steam generator rose above the reactor trip setpoint of 93.7 percent, initiating an automatic reactor trip. Operators carried out the actions of Procedure 2202.001, Revision 2, "Standard Post Trip Actions," and transitioned to Procedure 2202.002, Revision 1, "Reactor Trip Recovery." All safety systems responded as expected. Step 20 of Procedure 2202.002 required operators to verify that adequate shutdown margin existed. The licensee determined that adequate shutdown margin did not exist and initiated emergency boration.

The licensee determined that the reactor trip occurred when a painter, painting in the Unit 2 main chiller room, placed his foot on an angle iron near Feedwater Flow Transmitter FT-1129 and inadvertently opened the flow orifice flush valve on the transmitter's instrument sensing line with his foot. Because a cap was missing from the sensing line, the painter observed steam coming out the end of the small instrument line. The foreman stopped the leak by closing the valve and contacted the control room operators to notify them of the incident. Control room operators determined that the indications observed in the control room just prior to the trip were consistent with the transmitter's flush valve being inadvertently opened. With this valve opened, the differential pressure across the transmitter changed such that a signal was sent to the feedwater control system, which indicated that a low feedwater flow condition existed. The feedwater control system compensated by increasing feedwater flow which caused the water level in the steam generator to increase above the high level reactor trip setpoint.

Prior to the start of painting activities in the Unit 2 main chiller room, an auxiliary operator performed a prejob walkdown of the room in accordance with Procedure 1045.003, Revision 0, "Control of Painting," Attachment 1, "Walkdown of Area to be Painted." One of the purposes of the walkdown was to identify, list, and flag equipment which had the potential to adversely affect plant operations if the equipment was disturbed. The painting foreman then identified the listed and flagged equipment to the painters during the prejob brief to heighten their awareness of the location of the sensitive equipment and remind them to use caution when painting in the vicinity of this equipment.

In their review of the factors which contributed to the reactor trip, the licensee identified that, although the auxiliary operator did discuss the feedwater flow transmitter with the painting foreman, the auxiliary operator failed to list it as sensitive equipment on Attachment 1 to Procedure 1045.003 and did not place a flag on the transmitter to provide a visual caution to the painters. The inspectors reviewed the completed attachment and confirmed that the auxiliary operator did not list Flow Transmitter FT-1129 as trip sensitive equipment. During interviews, the auxiliary operator indicated that the transmitter should have been listed but was inadvertently omitted. Although not a direct cause of the trip, the inspectors concluded that the prejob walkdown, which was a potential barrier in preventing this reactor trip, was inadequate in that the operator failed to list and flag the transmitter as trip sensitive equipment.

In addition, the licensee determined that a cap on the end of the instrument sensing line was missing. Had this cap been installed, it would have prevented the venting of the flow transmitter when the valve was inadvertently opened and the reactor trip could have been avoided. The inspectors reviewed a job order which the licensee indicated had been used during a feedwater venturi inspection in April of 1994. The inspectors found that Job Order 00910273 did not include instructions for reinstalling the cap on the sensing line. The inspectors concluded that the failure to have or reinstall the cap on the instrument line was a poor maintenance practice and represented an additional failed barrier to the prevention of this reactor trip.

In response to this trip, the licensee took the following corrective actions:

- Suspended all painting and associated activities in the vicinity of trip sensitive equipment.
- Counseled the painter involved and held meetings with painting and housekeeping personnel to discuss the event, reviewed a video covering trip sensitive equipment, and discussed management's expectations on accessing work locations.
- Performed a walkdown of the Unit 2 turbine and auxiliary buildings and installed 16 caps on lines which were missing caps.

In addition, the licensee planned to evaluate prejob walkdowns for painting activities and the process for capping sensing line vents and drains to determine if improvements or enhancements were necessary. The licensee also planned to conduct walkdowns of Unit 1 to identify and install missing caps on sensing lines. The inspectors determined that the licensee's corrective actions were comprehensive.

2.1.1 Shutdown Margin

Following the reactor trip, and with the plant in Mode 3, the licensee performed a shutdown margin calculation in accordance with Procedure 2103.015, Revision 31, "Reactivity Balance Calculation," and determined that they did not meet the minimum shutdown margin of 5.5 percent delta k/k required by TS 3.1.1.1. The shutdown margin was calculated to be 4.6 percent delta k/k. As required by TS 3.1.1.1 and Procedure 2202.022, "Reactor Trip Recovery," operators initiated emergency boration to establish the required shutdown margin.

TS 3.1.1.1 required that the shutdown margin be greater than or equal to the limit specified on the core operating limits report when the plant was in Modes 1 - 4. The core operating limits report stated that the shutdown margin shall be greater than or equal to 5.5 percent delta k/k in Modes 1 - 4 when the average reactor coolant system temperature was greater than 200°F. Shutdown margin is defined in TSs as the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all CEAs are fully inserted, except for the single assembly of highest reactivity worth which is assumed to be fully withdrawn. Given this definition, the inspectors questioned the licensee regarding their ability to meet the shutdown margin requirement in Mode 1 if they could not meet it in Mode 3 following a reactor trip.

The licensee indicated that in Mode 1 TS 3.1.1.1 required operators to determine that the shutdown margin was greater than or equal to 5.5 percent delta k/k by verifying every 12 hours that control element assembly group withdrawal was within the transient insertion limits of TS 3.1.3.6. This ensured that the shutdown margin requirement would be met immediately following a reactor trip. However, due to the cooldown of the reactor coolant system to no-load conditions following a reactor trip, sufficient positive reactivity was added such that the calculated shutdown margin no longer satisfied the requirements of TSs and emergency boration was required to be initiated. The licensee indicated that, although reactor engineering had anticipated this condition for late-in-cycle core conditions, operations personnel had not. A condition report was written to document the lack of communication, training, and guidance provided to operators for this situation.

In response to this situation, the licensee revised Procedure 2202.001, Revision 2, "Standard Post Trip Actions," to add a step which directed operators to initiate emergency boration following a reactor trip. In addition, the licensee was evaluating long-term corrective actions to ensure Mode 3 shutdown margin requirements would be met following a reactor trip.

The inspectors conferred with the Office of Nuclear Reactor Regulation to determine acceptability of a licensee not being able to meet the TS shutdown margin requirements shortly after a reactor trip. The inspector concluded that, although it was not desirable for a plant to be below the minimum shutdown margin requirements following a reactor trip, it was acceptable based on the licensee's TS definition for shutdown margin.

2.2 Unit 2 - Reactor Trip Induced by ASI Exceeding Trip Setpoint

2.2.1 Description of Event

On September 2, 1995, Unit 2 operators commenced a reactor startup following the reactor trip, which had occurred approximately 26 hours earlier (Section 2.1). The startup was conducted in accordance with Procedure 2102.016, Revision 3, "Reactor Startup," and the reactor became critical at 3:26 p.m. Operators stabilized power at approximately 2 percent to allow for shift turnover.

The oncoming crew conducted a pre-evolution brief prior to assuming their duties to discuss the upcoming activities. The remainder of the plant startup was to be conducted in accordance with Procedure 2102.004, Revision 21, "Power Operation." The duties of each operator were discussed, and two additional operators were assigned to assist with the startup in the control room. One would coordinate the warming of the main turbine and the other would monitor and control the steam dump and bypass control system. The control board operator - turbine (CBOT) was responsible for controlling steam generator levels, and the control board operator - reactor (CBOR) was responsible for monitoring and controlling reactor power.

Procedure 2102.004 indicated that an ASI auxiliary reactor trip was enabled when the average of the CPC raw neutron flux inputs exceeded 17 percent power. If the ASI is outside the range of plus or minus 0.5 when the average of the CPC raw neutron flux inputs exceeded 17 percent, then a reactor trip would occur. In order to determine the average value for CPC raw neutron flux power, the operators had to calculate the average of CPC raw neutron flux power from three excore detectors in each CPC channel. During the crew brief, operators discussed this ASI auxiliary reactor trip and decided to stop the power ascension at 10 percent power and reduce ASI to -0.4, which was within the range of plus or minus 0.5.

When the crew assumed the shift, reactor power was approximately 2 percent and ASI was approximately -0.78. The crew continued to increase power according to Procedure 2102.004. During the power increase, the CBOR monitored ASI, calibrated neutron flux power, and CPC raw neutron flux power. The operators periodically averaged the three CPC raw neutron flux inputs to determine how close they were to the ASI auxiliary trip enable setpoint of 17 percent. Procedure 2102.004 cautioned operators that other power indications may read 4 - 5 percent lower than the calculated CPC raw neutron flux average power. The procedure also required operators to restore the ASI to within plus or minus 0.4 on all CPCs using Attachment A, "Reactor Maneuvering Rates and ASI Control During Maneuvers," prior to exceeding 17 percent raw neutron flux average power on any CPC.

As expected, the operators experienced difficulty controlling steam generator level during the startup. These difficulties were compounded by the fact that Pressure Indicating Switch 2PIS-0644 for the high pressure condenser shell began spiking. This generated a signal that blocked the opening of three main steam bypass valves to the condenser making steam generator water level control even more difficult. The control room supervisor (CRS) believed that it would be easier to control steam generator levels by increasing power above 10 percent, and the crew increased and stabilized power between 12 and 14 percent calibrated neutron flux power indication to resolve the level control problems. While at this power level, the operators periodically calculated average CPC raw neutron flux power and found that it remained between 14 and 16 percent.

Although Pressure Indicator 2PIS-0644 stopped spiking and the operator regained control of steam generator pressure, steam generator levels continued to oscillate which caused the control room operators, including the CRS, to focus on trying to stop the oscillations. Subsequently, the CRS refocused his attention on the CPC raw neutron flux power indications and mentally calculated CPC raw neutron flux average power to be 16.2 percent. Concerned that average CPC raw neutron power was too close to 17 percent, the CRS decided to lower power and directed the CBOR to begin borating the reactor coolant system. The CBOR borated the reactor coolant system and the operators noticed that calibrated neutron flux power began to slowly decrease. However, the positive reactivity added, due to the decay of xenon combined with steam generator level swings, caused enough change in reactor power such that the average CPC raw neutron flux power exceeded 17 percent. At approximately 7:27 p.m., with ASI outside the range of plus or minus 0.5, CPC raw neutron flux power exceeded 17 percent on CPC Channels C and D and a reactor trip signal was generated. All safety systems responded as expected.

2.2.2 Root Causes

In their root cause determination, the licensee found that the operators exceeded 17 percent average raw neutron flux power while ASI was outside the trip setpoint range of plus or minus 0.5, because of inadequate monitoring of both ASI and the average raw neutron flux power. The licensee concluded that a lack of operator experience related to end of core life with xenon present during reactor startup coincident with plant equipment problems and difficulties maintaining steam generator levels contributed to improper monitoring of these parameters. The licensee identified the following root causes:

(1) The crew expected and relied on ASI becoming less negative as power increased. The operators expected that power would shift from the top to the bottom of the core as core outlet temperature changed during the power escalation, therefore, making ASI less negative. During the power escalation, ASI did not significantly change and the licensee concluded that the crew should have stopped the power increase much earlier to address ASI response.

(2) The operators did not follow Attachment A, "Reactor Maneuvering Rates and ASI Control During Maneuvers," of Procedure 2102.004. The attachment noted that ASI was large following a reactor trip and recommended that Group 6 control element assemblies (CEAs) be at least 75 inches withdrawn when escalating power from 2 percent to control ASI. When the night crew assumed the shift, the CEAs were 145 inches withdrawn. Sometime during the power increase, the CBOR inserted the CEAs 10 inches to reduce ASI, but the operator found that inserting the CEAs had little effect on ASI.

(3) The crew lacked experience and sufficient training in performing a startup at the end of core life with xenon present. The licensee stated that, since the plant had not tripped in the last 5 years, the crew had not performed a startup where the presence of xenon in the core may affect plant power escalation. The licensee found that the four licensed operators involved in the startup had never performed a startup under these conditions. Additionally, the licensee concluded that the simulator did not satisfactorily model ASI response during power escalation with the core at the end life. As a result, the operators did not have an opportunity to train under those conditions; and, therefore, the operators were not proficient in addressing the unusual ASI behavior.

In addition to the root causes, the licensee identified the following underlying contributing causes to the event.

(1) Control room personnel were distracted by the difficulties in maintaining steam generator levels at low power. The licensee found that the CBOR focused his attention on maintaining steam generator level, rather than reactor power, to anticipate

reactivity effects of steam generator pressure fluctuations on reactor power. Further, the CRS and the shift superintendent (SS) were distracted from their primary overview responsibility by periodically monitoring steam generator level rather than monitoring operation of the plant as a whole. Additionally, the SS became directly involved in arranging and coordinating maintenance support for the troubleshooting of Pressure Indicating Switch 2PIS-0644.

(2) The need for the operator to manually calculate the average CPC raw neutron flux power was a burden that distracted the CBOR and had the potential for creating operator error. The licensee concluded that monitoring a single control room display for total CPC raw neutron flux power, instead of calculating an average CPC raw neutron flux power, would eliminate this distraction.

(3) Procedure 2102.004 did not specify a power level at which the power ascension should be stopped in order to reduce ASI below the trip setpoint prior to exceeding 17 percent average CPC raw neutron flux power. The licensee concluded that a specified hold point would reduce the likelihood of this type of reactor trip.

The licensee also determined that a possible cause of the event was the number of operators assigned to the control room panels. Normally, the licensee assigned two (CBOR and CBOT) rather than four operators for the power escalation. The licensee concluded that increasing the number of operators made control room communication difficult because of increased talkovers. The difficult communication increased the demand on the CRS's ability to manage the evolution and coordinate the efforts of the operators.

2.2.3 Corrective Actions

The licensee developed a list of recommended corrective action items which included the following items:

- Evaluate improvements in modeling transient ASI, including end of core life, with xenon present, and low power conditions on the simulator. Upon completion of this action item, the licensee proposed that the operators be trained on low power simulator scenarios during operator requalification.

- Install a digital feedwater control system, which would enhance operator control of the feedwater system at low power levels.

- Eliminate the operator burden of calculating average CPC raw neutron flux power by installing computer points which display this value to operators.

- Provide operators theoretical training on ASI behavior over core life and the effects of xenon on ASI.

- Revise Procedure 2102.004 to improve guidance on ASI control during low power maneuvering conditions.

The inspectors concluded that the proposed corrective actions were acceptable to address the issues.

2.2.4 Inspection Findings

Through a review of control room logs, procedures, and interviews with operations personnel who were involved with the reactor startup and subsequent trip, the inspectors independently verified the sequence of events leading to the reactor trip. The inspectors reviewed the licensee's root cause evaluation and found it to be self-critical and thorough. In addition, the licensee's proposed corrective actions appeared to be comprehensive.

The inspectors found that Step 8.6.10 of Procedure 2102.004 required operators to restore ASI to within plus or minus 0.4 on all CPCs using Attachment A of the procedure prior to exceeding 17 percent average CPC raw neutron flux power on any CPC. The failure to restore ASI within plus or minus 0.4 before exceeding 17 percent average CPC raw neutron flux power, resulting in an automatic reactor trip, was identified as a violation of TS 6.8.1.a. This self-disclosing and licensee corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy.

2.2.5 Conclusions

The inspectors concluded that weaknesses in command and control, use of procedures, and operator performance led to the automatic reactor trip.

Weaknesses in command and control were evident in that the SS and CRS became focused on specific problems, such as the faulty pressure indicating switch and the steam generator level control problems, and did not maintain proper oversight of the startup activity. In addition, they were not proactive in controlling ASI and did not establish sufficient margin between average CPC raw neutron flux power and the ASI trip enable setpoint of 17 percent.

Procedures were not properly used by the operators during the performance of this startup. Procedure 2102.004 provided the operators with the trip setpoint for ASI, instructed them on how to calculate average CPC raw neutron flux power, directed them to use Attachment A for the control of ASI during power escalation, cautioned them that other power indications may read 4 - 5 percent lower than the average CPC raw neutron flux power, and directed them to restore ASI to within plus or minus 0.4 prior to exceeding 17 percent. Despite these notes, cautions, and procedural steps, power was allowed to go above 17 percent with average CPC raw neutron flux power outside the trip setpoint range of plus or minus 0.5.

Operator performance was weak in that the crew failed to adequately monitor CPC raw neutron flux power, as directed in the procedure, to prevent it from exceeding 17 percent with ASI above the trip setpoint.

2.3 Water Intrusion into the Postaccident Sampling System (PASS) Building

On September 4, 199 , water entered the PASS building through the roof during a thunderstorm. Water entered Motor Control Center B33 causing a short on the supply side of the Main Breaker 52-313 cubicle. An automatic transfer to a Unit 2 Breaker 2B72 occurred, but this breaker reopened immediately due to the short on Motor Control Center B33. A smoke alarm went off and the licensees' fire brigade responded but only found smoke in the room.

The PASS building has had several minor leaks, historically, due to a poor initial design of the building where a seam extends through the PASS floor, room, and roof. The licensee corrected the previous minor leaks. On May 4, the licensee identified more leakage into the building and wrote a job request. The licensee dispositioned this job request as minor maintenance since the leak was not severe. The licensee speculated that a sealant over a roof joint significantly deteriorated during August since the sealant was approximately 15 years old and the weather was hotter than normal. After the water intrusion into the building, the licensee performed some temporary repairs to the roof. The licensee is currently investigating a long-term fix for the roof.

This loss of power rendered the PASS building and equipment without power. The equipment affected by this loss of power included PASS equipment, super particulate iodine and noble gas (SPING) Monitors 1 - 10, seismic equipment, and wall outlets in the building.

Both units entered TS action statements associated with the loss of PASS, Seismic Monitors and SPINGs 1 - 10. TSs required that alternative sampling capability for inservice effluent paths be implemented. There is no time given in the TSs to implement this alternative sampling capability, but the licensee self-imposed a limit of 1 hour to establish alternate sampling capability. SPINGs 2 and 6 monitor gaseous radioactive waste effluent paths for radioactivity. Due to a loss of normal power, a lack of sample pumps, and routing extension cords to these pumps, the 1-hour time clocks for SPINGs 2 and 6 were exceeded. The maximum time the effluent flowpaths were out of service was 1 hour 21 minutes. The licensee intends to submit an LER on these events.

The inspector concluded that the licensee's interim actions were appropriate to the circumstances.

2.4 Contamination of Unit 1 Service Air System

On September 11, 1995, during a routine blowdown of the Unit 1 service air receiver, a Unit 1 auxiliary operator observed more water than usual coming from the service air receiver. The licensee sampled the water and found that it was contaminated with radionuclides associated with the reactor coolant system. Since there had been a spent resin transfer that day, and service air can be used to backflush the resin transfer lines, they checked the service air valve connection to the spent resin transfer system and found contaminated water at that connection.

Unit 1 operators, radiation protection technicians, and chemists quickly checked other systems which were connected to the service air system and found that none were contaminated. The licensee depressurized the service air system and began sampling air connections to determine the extent of the contamination. The licensee determined that approximately half of the service air system was contaminated.

The Unit 1 service air system is a nonsafety-related system, which provides compressed air for use on demand throughout the plant. Two air compressors maintain the system pressure between 90 and 100 pounds per square inch gauge (psig) and an air receiver provides a reserve of compressed air for instant use. Unit 1 service air interfaces with other systems, including Unit 2 service air, Unit 1 instrument air, and the domestic water surge tank. The system also provides sparging air to different tanks, including the filtered waste monitor tank and dirty waste drain tank. Service air can also be used to clear obstructions in the resin transfer line through a temporary connection at the drumming station.

2.4.1 Sequence of Events

The licensee had been transferring spent resin from the Unit 2 spent resin storage tank to a shipping cask in accordance with Procedure 2104.017, "Spent Resin Transfer." On September 7, 1995, the line between the spent resin storage tank and the shipping cask became obstructed. As part of a troubleshooting effort, a waste control operator connected Unit 1 service air to the resin transfer line to verify that the portion of the line back to the spent resin transfer storage tank was clear. A pressure indicator at the storage tank registered an increase in pressure indicating the line was clear. However, the operator identified some resin in a flow gauge and stopped the evolution until the gauge could be cleared. The air connection was left in place.

The licensee continued the spent resin transfer on September 11 and was initially successful in transferring spent resin to the cask. However, the line again became obstructed and the waste control operator attempted to clear the line in accordance with Procedure 2104.017, Supplement 11, "Resin Transfer from Spent Resin Tank 2T13 to the Shipping Cask in the Train Bay." Supplement 11 provided guidance to clear the resin transfer lines using water from the Unit 2 condensate transfer system. This was not successful and the operator tried to clear the line in accordance with Procedure 2104.017, Supplement 13, "Backflush Procedure," which directed the operator to use the Unit 1 condensate transfer system and Unit 1 service air to clear the lines. The shutoff head of the Unit 1 condensate transfer pump was less than the Unit 1 service air system pressure; therefore, water would not enter the service air system. The backflush procedure was not successful in freeing the obstruction. During these attempts to clear the line, the operator was able to determine which section of the line was obstructed.

Since previous attempts at clearing the transfer line had failed, the waste control operator developed a plan, derived from portions of Supplements 11 and 13, to create pressure surges in the pipe by alternately supplying Unit 1 service air and water from the Unit 2 condensate transfer pumps to free the obstruction. This plan was not covered by any of the supplements of Procedure 2104.017. As the operator performed this evolution, personnel noticed spikes in water flow and water entering the cask and believed their efforts were successful in clearing the line. The operator continued alternating the supply of service air and flush water to the header until the cask dewatering pump failed. (The licensee later determined that the air driven cask dewatering pump failed due to water intrusion into the service air system.) Since the end of the shift was near, operators suspended further spent resin transfers for that day.

Following the discovery of the contamination in the Unit 1 service air system on September 11, the licensee determined that, by using the Unit 2 condensate transfer pumps, which had a shutoff head of approximately 170 psig, and Unit 1 service air, which had a header pressure of approximately 95 psig, contaminated water and spent resin were forced into the Unit 1 service air system during the operator's attempts to clear the resin transfer line. Unit 1 procedures required that, during flushes of hot spots, a check valve be used on temporary connections when flushing contaminated systems from a clean system to prevent contamination of the clean system. However, Unit 2 procedures did not provide these same instructions and a check valve was not used in the temporary service air line.

The failure to use a procedure in attempting to clear the obstructed resin transfer line, resulting in the extensive contamination of the Unit 1 service air system, was identified as a second example of a violation of TS 6.8.1.a (368/9507-01).

2.4.2 Licensee Efforts to Decontaminate the Service Air System

As previously discussed, the licensee depressurized the service air system to determine the extent of the problem and emptied the water from the service air connections. The licensee determined that approximately half of the service air system was contaminated. Although the licensee had developed a plan to flush the system, the inspectors noted that they did not have documented instructions on where to flush the system and at what contamination level the system would be declared clean. The licensee indicated that they were working on the system without instructions since the entire system was tagged out. Following the inspector's questioning, the licensee wrote temporary operating instructions to flush and decontaminate the system. The inspector observed portions of the licensee's flushes and found that their efforts were thorough. The licensee ran flush water through each connection for approximately 30 minutes after no detectable contamination was found. Except for the portion of line from the drumming station to the air receiver tank, the licensee was successful in flushing the service air system branches until no contamination could be detected.

While flushing the portion of the system from the drumming station to the air receiver tank, the licensee identified resin beads in the tank and postponed flushing this header until a new procedure could be developed. The licensee intended to flush this section at a later date. In order to restore as much of the service air system as possible, the licensee connected a temporary air compressor to the system using Temporary Modification 95-1-037.

The inspectors concluded that the licensee's identification of and response to the contamination of the service air system was good. Unit 1 operators quickly identified the source of the contamination and personnel sampled connected systems to determine the extent of the contamination. During the licensee's efforts to quantify the extent of the service air system contamination and develop a plan to flush and clean the system, the inspectors noted that the licensee's system engineers provided good assistance by reviewing service air system isometric drawings to determine the extent of the contamination. Further discussion of this event is contained in NRC Inspection Report 50-313/95-21; 50-368/95-21, which described the licensee's process to recover the service air system as well-planned with adequate management attention and oversight.

3 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.

During tours of the control room, the inspectors verified proper staffing, access control, and operator attentiveness. The inspectors identified thorough communication among operating crew members and during shift turnovers. The inspectors observed that, during shift meetings held at the beginning of each shift, crews not only discussed plant status, problems, and scheduled evolutions, but also industry events which may be applicable to ANO and radiation exposure goals and ways to reduce exposure.

The inspectors examined the status of control room annunciators, various control room logs, and other available licensee documentation. The inspectors evaluated the licensee's entries and exits from TS action statements and evaluated degraded out-of-service equipment to ensure licensed operators made appropriate operability determinations and complied with TS limiting conditions for operation.

The inspectors toured the facility during normal and backshift hours to assess general plant and equipment conditions and housekeeping and found them to be satisfactory. Discrepancies identified by the inspectors were minor and promptly corrected. The inspectors observed that the licensee was proactive in identifying and correcting housekeeping problems. Procedures maintained in the plant were verified to be the current revision.

4 MAINTENANCE OBSERVATIONS (62703)

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:

- Unit 1 - Job Order (JO) 00936485, "Control Room Emergency Filter Carbon Changeout," on August 17, 1995.

- Unit 2 - JO 00933219, performed in accordance with Procedure 2411.020, Revision 3, "Waste Gas Compressor Lubrication and Inspection," on August 17.

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.

On August 17, 1995, the inspectors observed mechanics perform portions of Procedure 2411.020, Revision 3, "Waste Gas Compressor Lubrication and Inspection." During the performance of this maintenance activity, the mechanics identified that Step 8.4.4 of the procedure specified the wrong type of fitting to be disconnected from the discharge of a compensating pump. The mechanics appropriately stopped the activity to resolve the inconsistency. The system engineer, who was present during the performance of the maintenance, confirmed that the procedure was in error and initiated actions to change the procedure. The inspectors concluded that the licensee took appropriate actions in response to the procedural error and noted that the presence of the system engineer, during the performance of the test, indicated active engineering involvement in day-to-day plant operations.

5 SURVEILLANCE OBSERVATIONS (61726)

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 - JO 00926631 performed in accordance with Procedure 2304.102, Revision 21, "Unit 2 Excores Safety Channel C Test," performed on September 1, 1995.

- Procedure 1105.005, "Emergency Feedwater Initiation and Control Quarterly test of Main Steam and Main Feed Isolation Valves," on September 14.

The inspectors concluded that the licensee safely performed these surveillance tests in accordance with established procedures. Selected observations from review of surveillance activities are discussed below.

On September 1, 1995, the inspectors observed as instrumentation and controls technicians performed portions of Procedure 2304.102, Revision 21, "Unit 2 Excores Safety Channel C Test." This test, performed to verify the proper operation, indication, and alarm functions of the logarithmic channel of the Unit 2 Safety Channel C Excore Drawer, was required by TS 4.3-1.3 to be conducted within 7 days of a reactor startup. The licensee anticipated performing a reactor startup on September 2 following their reactor trip on September 1.

The inspectors observed that communications among the technicians performing the test and with the control room operators were good. The technicians accurately read and recorded the required data during the test, recognized that a bistable tripped at a lower value than allowed, and made the appropriate adjustments. The technicians properly restored the system at the conclusion of the test. A good work practice was observed when a technician, positioned at the back of the cabinet, guided the drawer cables as the drawer was inserted into the cabinet.

6 ONSITE ENGINEERING (37551)

During this inspection period, the inspectors found that the licensee's engineers were actively involved in the day-to-day operation of the plant and in resolving problems which arose. As previously discussed in Sections 2.4 and 4.2, system engineers were involved with efforts to resolve the extensive contamination of the Unit 1 service air system and participated in plant equipment maintenance activities. In addition, engineering personnel performed operability determinations to support plant operations and were proactive in identifying and resolving engineering issues.

7 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.

As discussed in Section 2.4, the licensee's identification and response to the contamination of the service air system was good. Unit 1 operators quickly identified the source of the contamination and personnel sampled connected systems to determine the extent of the contamination. The licensee developed an effective plan to quantify the extent of the service air system contamination and to flush and clean the system. The licensee's process to recover the service air system was well planned with adequate management attention and oversight. Further discussion of this event is contained in NRC Inspection Report 50-313/95-21; 50-368/95-21.

8 FOLLOWUP - PLANT SUPPORT (92904)

NRC Inspection Report 50-313/95-13; 50-368/95-13 documented a concern that normal lighting in the Unit 2 MSIV room was poor and questioned the adequacy of emergency lighting in the room and the possible impact on an operator's response to an event requiring safe shutdown actions. The licensee assessed the condition and determined that, although the normal lighting in the room was not very good, there was sufficient light in areas where manual valve and component manipulations may be performed. In addition, the licensee found that the emergency lighting in these areas was "excellent."

The inspectors conducted an independent assessment of normal and emergency lighting in the Units 1 and 2 MSIV rooms. The normal lighting in the Unit 1 MSIV room was very good and the emergency lighting appeared to be adequate. The inspectors concurred with the licensee's assessment regarding the normal lighting in the Unit 2 MSIV room. The inspectors also found that the emergency lighting appeared to be adequate to perform local operator actions contained in Procedure 2203.014, "Alternate Shutdown," including local operation of the steam generator atmospheric dump valves, manual operation of the dump valve isolation valves, and local isolation of instrument air to the dump valves and the MSIVs.

9 IN-OFFICE REVIEW OF LERs (90712)

The following LER was closed based on an in-office review of the event. The review verified that the appropriate reporting requirements were met, the licensee took the appropriate corrective actions, and no additional inspection activities were required to review the specific issues:

- LER 313/95-009, "Reactor Trip on High Reactor Coolant System Pressure which Resulted from Closure of the Main Turbine Governor and Intercept Valves Due to the Failure of a Main Generator Output Circuit Breaker Contact."

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
C. Anderson, Unit 2 Operations Manager
R. Byford, Training
T. Brown, Unit 1 Outage Manager
R. Carter, Unit 2 Assistant Operations Manager
B. Eaton, Unit 2 Plant Manager
R. Edington, Unit 1 Plant Manager
R. Espolt, Events Analysis and Assessment Manager
R. King, Acting Licensing Director
R. Lane, Design Engineering Director
J. McWilliams, Modifications Manager
T. Mitchell, Unit 2 System Engineering Manager
M. Ruder, Plant Assessments
B. Short, Licensing Specialist
M. Smith, Licensing Supervisor
J. Sutterfield, Unit 2 Shift Superintendent
L. Taylor, Plant Assessment
D. Wagner, Quality Assurance Supervisor
L. Waldinger, Plant Operations General Manager
T. Weir, Site Business Service Manager
A. Wrape, III, 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 September 22, 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.