## APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/93-11
50-368/93-11

Licenses: DPR-51
NPF-6

Licensee: Entergy Operations, Inc.
Route 3, Box 137G
Russellville, Arkansas

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: December 26, 1993, through February 5, 1994

Inspectors: L. Smith, Senior Resident Inspector
E. Ford, Senior Resident Inspector
S. Campbell, Resident Inspector
J. Melfi, Resident Inspector

Accompanying Personnel: K. Weaver, Engineering Aide

Approved: Thomas F. Stetka 4/1/94
Thomas F. Stetka, Chief, Project Branch D Date

Inspection Summary

Areas Inspected (Units 1 and 2): This routine, announced inspection addressed onsite event followup, operational safety verification, monthly maintenance observation, bimonthly surveillance observation, followup on previous inspection items, and onsite review of licensee event reports (LERs).

Results (Units 1 and 2):

- Operator response to a Unit 1 loss of control rod drive (CRD) cooling was inappropriate and resulted in one of two examples of a violation of Technical Specification 6.8.1 (Section 2.1).

- All annunciators listed in the Unit 2 out-of-service logbook were associated with nonsafety-related equipment. The logbook was well organized, auditable, and traceable (Section 3.1).

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- A violation of 10 CFR Part 50, Appendix B, Criterion V (368/9311-01) was identified. Weak programmatic controls for plant changes resulted in emergency diesel generator air start system drain valves not being included in the appropriate operating instructions (Section 3.2).

- Unit 2 potentially operated for extended periods of time at greater than the licensed power limit. This issue will be tracked by an unresolved item (Section 3.3).

- The licensee satisfied Technical Specification operability requirements for the Unit 2 charging pumps even though Pump 2P-36C was determined to be inoperable due to gas binding (Section 3.5).

- Unit 1 personnel inadvertently injected chemicals intended for Unit 2 into the Unit 1 feedwater system. This action resulted in a second example of a violation of Technical Specification 6.8.1 (Section 3.6).

- Boration of the Unit 2 reactor coolant system was well controlled. The training deficiency related to boration control identified during recent NRC operator examinations was effectively remedied (Section 3.7).

- During routine tours the inspectors noticed several industrial safety weaknesses (Section 3.8).

- A Technical Specification required shutdown and startup for Unit 1 was well controlled (Section 3.9).

- All observed safety-related valves were determined to be in the correct position (Section 3.10).

- A housekeeping weakness was identified: the bulk fuel oil storage tank sump was full of fuel oil and water which submerged safety-related emergency diesel generator fuel oil valves under water (Section 3.11).

- Several minor maintenance items were identified by the inspectors (Sections 3.11 and 3.12).

- A noncited violation was identified involving a 1990 drafting error regarding ventilation piping for emergency diesel generator fuel oil tank level switches (Section 3.13).

- Observed maintenance activities were conducted in accordance with the Technical Specifications and appropriate procedures by qualified personnel (Section 4).

- The licensee's program for the control of leak sealant repairs was acceptable. A weakness was identified in that the gage used in the equipment for sealant injection was not calibrated. A leak sealant repair was successfully performed on the Unit 1 emergency feedwater pump turbine steam admission valve (Sections 4.1 and 4.2).

- One noncited violation was identified when a quality control inspector signed in on an incorrect radiation work permit (Section 4.5).

- Observed surveillance tests were conducted in accordance with the procedures and within the prescribed time frames (Section 5).

- Effective command and control was demonstrated when Unit 2 plant protection system testing was stopped during shift turnover (Section 5.4).

- An instrument technicians' close attention to detail during Unit 1 reactor protection system testing was commendable (Section 5.6).

Summary of Inspection Findings:

- Violation 368/9311-01 was opened (Sections 2.1 and 3.6).

- Violation 313/9311-02 was opened (Section 3.2).

- Unresolved Item 368/9311-02 was opened (Section 3.3).

- IFI 313/9309-04; 368/9309-04 was closed (Section 6.1).

- IFI 313/9310-03 was closed (Section 6.2).

- LER 368/91-015 was closed (Section 7).

Attachments:

Attachment 1 - Persons Contacted and Exit Meeting
Attachment 2 - Acronyms

## DETAILS

### 1 PLANT STATUS

#### 1.1 Unit 1

At the beginning of the inspection period, the unit was at 100 percent power. On January 7, 1994, the unit reduced power to 95 percent for turbine governor/throttle valve testing. The unit returned to 100 percent power the same day. On February 1, a notification of unusual event was declared because of a plant shutdown required by the Technical Specifications. The licensee identified that a level transmitter associated with the emergency feedwater system was inoperable. A special inspection was conducted (documented in NRC Inspection Report 50-313/94-12; 50-368/94-12) to review the licensee's actions related to identifying the inoperable transmitter. The plant returned to 100 percent power on February 3. The unit remained at 100 percent power throughout the remainder of the inspection period.

#### 1.2 Unit 2

At the beginning of the inspection period the unit was at 100 percent power. On January 11, 1994, the licensee reduced reactor power to 99 percent to compensate for a potential nonconservative error in the core operating limiting supervisory system (COLSS) which could have resulted in the calculated reactor power level being less than the actual reactor power level. A constant utilized in the COLSS computer program was corrected and the unit returned to 100 percent power on January 13. Seven days later the unit reduced power to 75 percent for condenser tube repairs. The unit returned to 100 percent power on January 23. The unit was at 100 percent power at the end of the inspection period.

### 2 ONSITE EVENT FOLLOWUP (93702)

#### 2.1 Unit 1 - Loss of Cooling to the Control Rod Drives (CRDs)

At 4:24 a.m. on January 7, with the unit at 100 percent power, CRD Cooling Water Pump P-79B tripped and Pump P-79A autostarted. The control room operators promptly dispatched an auxiliary operator to investigate the event. At 4:26 a.m., CRD Cooling Water Pump P-79A tripped. The licensee found that the ammonia pump pit, where the CRD cooling water pumps were located, had flooded. The auxiliary operator determined that a nearby domestic water system backflow preventer valve failed, resulting in the domestic water flooding the pit. It was subsequently determined that the CRD cooling water pumps had tripped on overload because of water entering the motor casing.

The CRD temperatures began to rise due to the lack of cooling, and the licensee began several concurrent actions to restore cooling. These actions included: (1) monitoring CRD temperature to assure that limits were not exceeded; (2) entry into Abnormal Operating Procedure 1203.003, "Control Rod

Drive Malfunction Action"; (3) placing the integrated control system in manual to prevent further CRD motion; (4) installing a temporary sump pump to remove the water; (5) running a CRD cooling water pump intermittently as much as possible to cool the CRDs; and (6) opening the CRD pump electrical cabinets to promote ventilation.

The inspector noted that followup actions specified in Abnormal Operating Procedure 1203.003 included: (1) tripping the reactor if the temperature of two CRDs exceeded 180°F; (2) venting CRD cooling water pumps, filters, and high points on lines and verifying that the non-nuclear intermediate cooling water temperature and flow are normal; and (3) if the temperature of one CRD exceeded 180°F, reducing reactor power to 40 percent and then de-energizing the affected CRD (which would cause the associated control rod to drop into the core). In this instance, the licensee determined that the maximum CRD temperature experienced during the event was 185°F and the next highest was 176°F.

The licensee did not initiate a power reduction in accordance with the procedure. Licensee management explained that lowering plant power would have required significant rod motion and would have increased the heat load in the CRDs.

The licensee stated that the duration of the overheating of the CRD was minimal and would not cause any long term degradation. At 5:29 a.m., Cooling Pump P-79B was returned to continuous operation and adequate cooling to the CRDs was restored.

The licensee's deviation from the requirements of Procedure 1203.003 is a violation of Technical Specification 6.8.1 (313/9311-01) (Example 1).

### 2.2 Conclusions

The licensee's response to rising CRD temperatures was nonconservative and contrary to the established abnormal operating procedure.

## 3 OPERATIONAL SAFETY VERIFICATION (71707)

### 3.1 Unit 2 - Review of Annunciator Out-of-Service Log

On December 30, 1993, the inspector reviewed the annunciator out-of-service log. The inspector reviewed condition reports, plant changes, plant engineering evaluation requests, job orders (JO), and job requests (JR) associated with the 18 annunciator out-of-service entries listed in the logbook. The oldest entry, dated June 25, 1992, regarded a letdown boron concentrator monitor which remained in the logbook because the equipment was removed from service and abandoned. The alarm still annunciates on low flow which is useful to the operators as an indicator of flow through a radiation monitor also installed in the line. The licensee planned to change the label on the annunciator to indicate radiation monitor flow low rather than boronometer flow low. The monitor and other abandoned equipment associated with the out-of-service annunciator received appropriate 10 CFR 50.59 reviews through the initiation and evaluation of related plant engineering action requests. The inspector confirmed that all annunciators listed in the out-of-service logbook were not associated with safety-related equipment. The logbook was well organized, auditable, and traceable.

3.2 Unit 2 - Inspection of Emergency Diesel Generators (EDG) 2K-4A and 2K-4B Fuel Oil, Lube Oil, Jacket Cooling Water and Starting Air System

The inspector reviewed the fuel oil, lube oil jacket cooling water, and starting air system and conducted field walkdowns during the period January 6 - 10 for EDGs 2K-4A and 2K-4B. Sheets 1, 2 and 3 of Piping and Instrumentation Diagrams (P&ID) M-2217; Revision 45, "Emergency Diesel Generator Starting Fuel Oil System"; Revision 34, "Emergency Diesel Generator Starting Air System"; and Revision 8, "Emergency Diesel Generator Auxiliary Systems," were used as guides respectively. Procedure 2104.036, Revision 36, "Emergency Diesel Generator Operations"; Attachment A, "2DG1 Valve Lineup"; and Attachment B, "2DG2 Valve Lineup"; were used to confirm valve positions.

While all valves were found to be in their appropriate positions, the inspector identified that Starting Air Compressors 2C-4A, 2C-4B, and 2C-4C Drain Valves 2ED-1040, 2ED-1041, and 2ED-1042, respectively, were not included in the valve lineups. Condition Report 2-94-0017 was written and a change to the procedure was made to include the missing valves. It was subsequently identified that the valves had been installed between November 1992 and March 1993, utilizing Plant Change 92-8024. These valves were added to prevent corrosion of the compressor unloader valves due to moisture. A procedure improvement form was written to include the valves in the valve lineup sheet but the licensee had not acted on the improvement form. The failure to include the valves in the valve lineup attachment following completion of the modification installation is a violation of 10 CFR Part 50 Appendix B, Criterion V (368/9311-02).

Because of the size of the drain valves and associated tubing, the licensee determined that the compressor was able to maintain starting air tank pressure with any of the valves opened. Therefore, the likelihood for total starting air tank air depletion was considered remote.

The inspector noted a procedure weakness. Procedure 2104.036 listed Expansion Tank Coolant Pump Suction Valves 2ED-23 and 2ED-15 as open versus locked open. These valves were locked open in the field as required by Procedure 2102.001, "Plant Pre-Heatup and Pre-Critical Checklist." A change to Procedure 2104.036 was made to include the requirement for locking the valves.

3.3 Unit 2 - Possible Operation Beyond the Licensed Power Limit

On January 11, 1994, the licensee received preliminary calculation results from Combustion Engineering which suggested that actual reactor power was 100.55 percent when indicated power was 100 percent. The licensee responded by reducing reactor power until indicated power was 99 percent while further analysis was conducted. Condition Report 2-94-0010 was initiated.

Procedure 2409.434, "Moisture Carryover/Feedwater Flow Rate Test," was performed on December 7, 1993. As the result of this test, feedwater flow was calculated to be 1.3 percent higher than indicated by the installed feedwater flow instrumentation. This feedwater flow instrumentation provided signals to the COLSS computer program for use in the secondary side calorimetric calculations. The moisture carryover was also measured during this testing and was determined to be .75 percent. This also was different than the 0 percent value used by the COLSS computer program to perform secondary side calorimetric calculations. These secondary side calorimetric calculation results were used to calibrate the nuclear instrumentation. Therefore, the feedwater flow and moisture carryover discrepancies had the potential for causing inaccurate measurements of reactor power.

On January 13, a constant in the COLSS computer program was adjusted to compensate for the potential feedwater and moisture carryover discrepancies while the test data were being reviewed. This change allowed indicated reactor power to be returned to 100 percent; however, the actual reactor power was still at 99 percent. This change was made for operator convenience.

The secondary side calorimetric calculation included allowances for instrument uncertainties of approximately 1.6 percent. The licensee has not yet completed their error analysis to determine the appropriate relationship between these measurement discrepancies and the instrument uncertainty already included in the calorimetric calculation. The licensee's review of the Combustion Engineering calculations also was not complete. The results of the licensee's assessments will be reviewed when they become available. Pending the inspector's review of these assessments, this is Unresolved Item 368/9311-03.

3.4 Unit 1 - Safety Review Committee Meeting

On January 13, 1994, the inspector attended a portion of the licensee's safety review committee meeting. During the meeting, the request for revision to the Unit 1 Technical Specification 3.5.1, related to protection instrument or channel failure, was reviewed. The members asked appropriate questions and gave the request a thorough evaluation.

3.5 Unit 2 - Operability of Charging Pumps 2P-36A and 2P-36B

On January 14, 1994, the inspector reviewed starting and stopping logs for Charging Pumps 2P-36A, 2P-36B, and 2P-36C following the discovery that Pump 2P-36C was inoperable because of gas binding of the pump cylinders, which was identified on December 15, 1993. There was no log entry which indicated that more than one pump was inoperable simultaneously. At least two charging pump trains remained operable whenever Pump 2P-36C exhibited a vapor lock.

The licensee initiated Condition Report 2-93-0273 to evaluate the operability of Charging Pump 2P-36C following two failures of the pump to deliver the design flowrate of 40 gallons per minute when started. In both cases the pump had remained idle for 2 or more days prior to the start demand. In each case the condition was subsequently cleared by draining the discharge piping and verifying that the discharge check valve closed and the discharge line pressure was reduced to approximately suction pressure. Pump 2P-36C apparently had some amount of leakage past the pump internal check valve. The gas binding condition existed because dissolved gasses came out of solution and migrated to the pump cylinders causing gas binding of the pump. The licensee initiated a program to routinely run and vent the charging pumps to ensure gas build up within the pump did not occur. Repairs were also performed on the leaking check valves.

The licensee stated they had visited other plants and were working with the Combustion Engineering Owner's Group to identify initiatives which would improve the reliability of these pumps, reduce maintenance, and reduce exposure. The licensee had identified one other utility that had experienced similar gas binding due to leaking internal check valves and leaking discharge check valves. The other utility had implemented similar compensatory measures, i.e., routinely running and venting the pumps.

### 3.6 Unit 1 - Inadvertent Injection of Ethanolamine (ETA) into Unit 1 Feedwater

On January 19, 1994, the wrong chemicals were injected into the Unit 1 feedwater system. These chemicals were used to control the pH of the feedwater. The Unit 1 feedwater pH was controlled by the injection of morpholine, while Unit 2 feedwater pH was controlled by the injection of ETA.

When operation's personnel requested replacement of a morpholine container, an ETA container was inadvertently provided. Both replacement containers were identical with the exception of the contents label. This ETA container was subsequently placed in service which caused a conductivity change in the feedwater. When operation's personnel noted the conductivity change, they investigated the reason for this change and determined that a wrong container was placed in service. The licensee disconnected the ETA container and connected a morpholine container.

The licensee initiated Condition Report 1-94-0015 to assess the effect of the ETA on the feedwater system and to determine how the wrong container was installed. The licensee concluded that no detrimental effect would occur to the feedwater system since ETA was a breakdown product of morpholine. The condition report was determined to be significant. As a result, they planned to do a formal root cause investigation to determine how to prevent recurrence of this problem.

Operating Procedure 1106.028, "Secondary System Chemical Addition," Section 10, provided instructions for the replacement of the morpholine container. The failure to perform the evolution in accordance with procedural requirements is a violation of Technical Specification 6.8.1 (313/9311-01) (Example 2).

3.7 Unit 2 - Power Reduction For Condenser Tube Repairs

On January 20 a boration of the reactor coolant system was planned to reduce reactor power for condenser tube repairs. The inspector observed this boration and found it was performed correctly in accordance with Procedure 2104.003, "Chemical Addition," Supplement 6, "RCS Boration During Power Operation."

While at reduced power, the licensee plugged three tubes that had very small leaks and stopped a very small leak in the tube sheet. This down power was performed to stop leakage which was not previously detectable. The licensee was using a new sulfur hexaflouride technique to identify the water box with the leak and then used helium injection to determine the water level and to identify the leaking tube.

During the weeks of December 6 and December 13, 1993, NRC licensed operator examiners observed that boration control during power operation on the simulator was inconsistent among the operators and not performed in accordance with procedures. These observations are detailed in NRC Inspection Report 50-313/93-32; 50-368/93-32. Based upon the observation of this boration evolution, the inspector concluded that this deficiency had been effectively addressed.

3.8 Units 1 and 2 - Plant Industrial Safety Weaknesses

During routine plant tours, the inspectors noticed several industrial safety weaknesses: (1) On January 19, the inspector noticed that a scaffold associated with JO 00901325 had an expired 30-day scaffold inspection tag on it. The inspector was told that work was still in progress which would utilize the scaffold. No workers were observed on the scaffold. (2) The inspector noticed that a permanently installed ladder on a platform by the Unit 1 main steam safety valves did not have a chain across it. The licensee initiated JR 897794 to install a chain. (3) Closure of a confined space near the service water intake structure was not coordinated well, in that the trap door was still open 3 weeks after the plant safety staff believed it to be closed. The opening was appropriately barricaded and posted. (4) Compressed nitrogen dewars in the postaccident sampling system room were not secured as required by the licensee's procedures. The inspector discussed this observation with the licensee and they were secured.

3.9 Unit 1 - Plant Shutdown to Repair Once Through Steam Generator (OTSG) Level Transmitter LT-2622 Inoperability

At 9:50 p.m. on January 31, operators declared Level Transmitter LT-2622 inoperable since it indicated about 16 inches greater than the other two channels. Procedure 1015.003A, Revision 31, "Unit One Operations Logs," required that Level Transmitter LT-2622 be declared inoperable when it indicated a value which varied from the other two channels by more than 8 inches. This transmitter inputs a signal to the emergency feedwater initiation circuitry. Sufficient redundancy was available so that Technical Specification 3.5.1 for emergency feedwater initiation instrumentation requirements were met. The transmitter signal was also used to control emergency feedwater (EFW) flow from EFW Pump A into OTSG A. Technical Specification 3.4.5(1), which was applicable since part of the EFW flow path was affected, required that the plant be taken to hot shutdown conditions within 36 hours.

The inspector observed portions of the shutdown from power operation to repair the level transmitter. The licensee correctly implemented their emergency plan and declared a Notification of Unusual Event since this was a shutdown required by Technical Specifications. This event was discussed further in NRC Inspection Report 50-313/94-12; 50-368/94-12. The shutdown was performed in a controlled manner. Workers entered containment and replaced Level Transmitter LT-2622.

During the shutdown, the inspector toured the reactor building with the licensee and found it to be free of debris and only insignificant leakage was observed. After replacing the transmitter, the licensee commenced a plant startup on February 2. The inspector observed portions of the startup and considered the startup to be well controlled.

3.10 Units 1 and 2 - Position Verification for Locked Safety-Related Valves

During this inspection period, the inspector verified that accessible safety-related locked valves for the Unit 2 high pressure safety injection and low pressure safety injection system were in the correct position.

Additionally, the inspector confirmed that the service water system safety-related locked valves for both units were in their proper position. All valves were observed to be appropriately aligned and locked.

3.11 Unit 2 - Inspection of Fuel Oil Vaults and Bulk Oil Storage Tank T-25

The inspector toured Fuel Oil Vaults A and B. P&ID M-2217, Revision 34, Sheet 1, "Emergency Diesel Generator Fuel Oil System," was used as a guide and Procedure 2104.036, Revision 36, "Emergency Generator Operations," Attachment A, "2DG1 Valve Lineup," was used to confirm valve alignments. Valves were positioned according to procedures; tank levels were acceptable; and all tanks were appropriately grounded.

The inspector identified the following items which required minor corrective maintenance: leakage from fire suppression Deluge System Valve 2FS-3271E, opened covers on the emergency main actuation deluge switches, and burned out light bulbs in Fuel Oil Vault B. The deficiencies were of minor safety significance and were quickly corrected by the licensee.

The inspector, concerned about licensee inspection activities in Fuel Oil Vault B in the absence of light, reviewed card key logs and confirmed that an entry was made after the last diesel surveillance test. The licensee stated that the light bulbs were not burned out at that time.

The inspector noted diesel fuel oil floating on top of rain water near the top of the Bulk Oil Storage Tank T-25 valve pit. Piping and valves leading to the safety-related portion of the EDG fuel oil systems for both units were submerged in water. The licensee determined that approximately 500 gallons of oil were floating on 3000 gallons of water.

The inspector reviewed chemistry sample results for the EDG Day Tanks 2T-30A and 2T-30B and Emergency Diesel Fuel Tanks 2T-57A and 2T-57B and confirmed that no water entered either systems. The inspector reviewed Procedure 1305.08, Revision 1, "Fuel Oil, Lube Oil Tank Integrity Check," and noted that there were no acceptance criteria for excessive oil in the valve pit which the inspector considered a weakness. The operators also considered a water/oil level above safety-related fuel oil Valve FO-4 as excessive. The failure to keep the sump pit pumped down was considered to be a housekeeping weakness.

The licensee drained the sump pit; performed maintenance to locate and correct the leakage problem; trained the operators regarding expectations for ensuring the pit was drained; and revised their program to provide for closer monitoring of the sump level.

3.12 Units 1 and 2 - Plant Tours

The inspector toured various elevations of the turbine and auxiliary extension buildings and made the following observations:

A rubber curtain behind a Motor Control Center 2B51 was not fully drawn across the back of all panels. This would have had the potential to expose the motor control center to fire protection system water spray. This situation was corrected by operations personnel.

A data logger in use near the reactor coolant pump vibration instrument racks in the electrical penetration room did not have a calibration sticker on it. This instrument was not required for testing but was used to monitor pump vibration for performance trending. As a result, the licensee was not committed to calibrate this piece of measuring and test equipment (M&TE). The licensee initiated a condition report to ensure M&TE used to monitor equipment performance would be calibrated.

A condolet cover from the Unit 1 Train A EDG fuel oil day tank level switches was open. These switches automatically controlled the transfer pump that supplies diesel fuel oil to the EDG day tank. The open condolet cover exposed the wire from these switches. The licensee initiated a JR, and the condolet cover was closed.

A heat trace temperature indicator on the nitrogen supply to the OTSG was broken. The system was operating and the licensee initiated JO 00908080 to fix the indicator. The heat trace was used to heat the nitrogen used during OTSG layup to minimize thermal transients to the metal.

The inspector noted licensee senior management (site vice president and the director of quality) touring inplant on several occasions. The licensee also was making commendable painting and preservation efforts in the turbine building.

### 3.13 Unit 1 - Drawing Errors Identified during Walkdowns

During walkdowns and tours of the plant, the inspector identified a drawing error on Drawing M-217, Sheets 2 and 3. Level Switches LSL-5206 and LSL-5209 autostart the diesel fuel oil transfer pumps when the day tank reaches a low level. These level switches were connected to the Train A and Train B diesel fuel oil day tanks, respectively. Drawing M-217 did not show the vent piping that was installed on these levels switches.

The licensee researched this item and found that due to a 1990 drafting error these vent lines were omitted from Drawing M-217. The licensee issued Drawing Revision Notices 400728 and 9400730, and anticipated the drawing updates to be completed by February 18, 1994. The licensee stated that there were no previous drawing revision notices on these vent lines. The failure to have a correct plant drawing is considered to be contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion III, which requires, in part, that design basis be accurately translated into drawings. This violation is not being cited because the criteria in Paragraph VII.B.1 of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice," were satisfied.

### 3.14 Conclusions

The Unit 1 plant shutdown to repair a level transmitter and subsequent restart were well controlled. The Unit 1 reactor building was free of debris and no significant leakage was identified. The Unit 2 power reduction to repair main condenser tubes was well controlled. An unresolved item was identified because moisture carryover and feedwater flow test results were preliminarily extrapolated to indicate that Unit 2 may have operated for an extended period of time at approximately 100.55 percent power. A violation was identified because weak programmatic controls for plant changes implemented while the plant was operating resulted in EDG air start system drain valves not being included in the appropriate operating instructions.

The licensee satisfied Technical Specification operability requirements for the Unit 2 charging pumps even though Pump 2P-36C was determined to be inoperable due to gas binding.

A violation was identified when Unit 1 personnel inadvertently injected chemicals intended for Unit 2 into the Unit 1 feedwater system. Several industrial safety weaknesses were identified by the inspectors.

The Unit 2 annunciator out-of-service log was well organized. Annunciator outages were appropriately controlled.

All observed safety-related valves were determined to be in the correct position. A housekeeping weakness was identified. The bulk fuel oil storage tank sump was full of fuel oil and water which submerged safety-related fuel oil valves in water.

A noncited violation was identified. The vent piping was not depicted for Level Switches LSL-5206 and LSS-5209 when P&ID M-217 was redrawn in 1990.

## 4 MONTHLY MAINTENANCE OBSERVATION (62703)

### 4.1 Units 1 and 2 - Use of Sealant Injection on Plant Components

The inspectors were notified of nine leak repair tasks involving sealant injection. Of the nine tasks, eight were performed on components that were not safety-related, not important to safety, or associated with the reactor coolant system boundary. The ninth task, which involved a leak repair on Steam Supply Isolation Valve CV-2617 to the turbine-driven EFW pump, was safety related.

The eight tasks required a peripheral seal or an encapsulation clamp around the component with minor or no peening involved. Three of the eight tasks necessitated two attempts of sealant injection to completely stop the leak. The licensee was aware of the event that was documented in Information Notice 93-90, "Unisolatable Reactor Coolant System Leak Following Repeated Applications of Leak Sealant." Th licensee trained maintenance personnel using a video tape released by the plant that was the subject of the Information Notice. The inspector viewed the tape and reviewed the roster of the personnel who watched the tape.

The licensee's guidance for this type of repair was in Procedure 1025.015, "On Line Repair Procedures." This type of temporary leak repair was regularly performed on valves; and written guidance on this process was developed from the vendor and other industry groups which included Electrical Power Research Institute Procedure NP-6523-D, "On-Line Leak Sealing." Procedure 1025.015 was revised to add peening precautions following the issuance of NRC Information Notice 93-90.

### 4.2 Unit 1 - Furmanite Repair of an EFW Pump Steam Admission Control Valve 2617 (JO 00907208)

Steam Admission Valve CV-2617 was not isolatable from OTSG E-24B. On December 30, 1993, operators noticed that the valve had a body-to-bonnet steam leak. The licensee decided to repair the leak with a peripheral clamp and the injection of Furmanite, a leak sealant. The inspectors reviewed the licensee's evaluation of the effects of the peening process on the body-to-bonnet bolts. The licensee's evaluation concluded that the peening activities would not induce any adverse stress on these bolts. The edge of the valve body and bonnet were peened to the peripheral clamp to form an enclosed volume for the Furmanite injection. The inspectors observed portions of the online repair. The activities were conducted in accordance with JO 00907028 and Procedure 1025.015.

During the observation, the inspector noticed that the pressure gauge used to monitor the injection pressure for the Furmanite was the vendors' gauge and not in the licensee's program for the calibration of M&TE. Review by the inspectors and the licensee of the Quality Assurance Manual revealed that this gauge was not required to be in the M&TE program. The licensee's commitment for implementation of 10 CFR Part 50, Appendix B, Criterion XII, which addresses the control and calibration of M&TE used in activities affecting quality, was limited in scope to M&TE used to perform inspections and tests for record. Through the review of EPRI and other industry data, the inspector determined there was no strong correlation between online leak repair pressures measured at the pump discharge and those sensed by the components injected. The gage is provided to preclude gross overpressurizations or excessive flows. Therefore, this pressure gauge was not used to perform an inspection with a meaningful acceptance criteria. The failure to use a calibrated gage in the injection equipment is considered a maintenance weakness.

The licensee agreed that this gauge should be in the M&TE program as a matter of good practice and modified Procedure 1025.015.

4.3 Unit 1 - Emergency Feedwater Initiation and Control (EFIC) Channel B Power Supply Replacement (JO 00894305)

At 12:06 a.m. on January 3, 1994, the EFIC TROUBLE annunciator alarmed. The licensee determined that the trouble alarm came from EFIC Channel B. The licensee initiated JR 020208, Condition Report 1-94-001, and entered Technical Specification 3.5.1-1. Technical Specification 3.5.1-1 allows 12 hours to reach hot shutdown if two EFIC channels are inoperable. Due to previous inoperability of EFIC Channel C, the licensee entered the 12-hour allowed outage time.

Instrumentation and control technicians investigated and determined that Power Supply PS-4 had failed.

The inspector observed portions of the power supply replacement. The leads to the power supply were lifted and landed correctly. The power supply was replaced and the replacement power supply operated satisfactorily.

4.4 Unit 2 - Replacement of Shutdown Cooling Drain Valve 2SI-1036 (JO 00893805)

On January 4, the inspector observed a portion of the replacement of Shutdown Cooling Drain Valve 2SI-1036. Upstream Valve 2SI-1033 was closed and hold carded to isolate the drain valve. The inspector reviewed training records of the welders and confirmed that the welders were qualified. The welders were qualified fire watches. An appropriate ignition source permit and a currently inspected full fire extinguisher were present at the job site. The replacement valve, which was identical to the previously installed valve, was American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Class I and was welded to lower class piping using filler rods compatible with the base material. A quality control inspector verified piping heat numbers and performed a visual inspection of the final fillet weld. All workers were knowledgeable of the correct radiation work permit (RWP) requirements. No limiting conditions for operation or action statements were required to be entered as a result of the evolution.

4.5 Unit 2 - Nondestructive Examination (NDE) of Weld Joint Following Valve 2SI-1036 Replacement (JO 00894305)

On January 5, the inspector observed NDE of the newly welded joints for Shutdown Cooling Drain Valve 2SI-1036. The licensee used a liquid penetrant test to detect defects in the weld to satisfy ASME Code requirements for inservice testing. Before the examination began, the inspector requested to see the JO associated with the NDE task. The licensee incorrectly assumed that the NDE would be performed under current JO 00893805 for welding rather than JO 00894305 for NDE. When the licensee was questioned about on-the-job RWP requirements, the inspector discovered that one individual, who had been working on the job before the inspector arrived, entered on an incorrect RWP. The individual entered on RWP 1994-0507 for Unit 1 permanent piping installation work rather than on RWP 1994-0506 for Unit 2 valve replacement work. The job was stopped until the licensee obtained and reviewed the correct JO. The individual on the incorrect RWP exited the radiologically controlled area and initiated Radiological Information Report 94-001 for an RWP violation. No overexposure to the individual was recorded, and no estimated limits specified on either RWP were exceeded.

The licensee, concerned over the poor radiation worker practice following the incorporation of a new RWP format, counselled the individual, initiated Condition Report C-94-0004, performed a human performance evaluation and requested that the individual devise a training plan to conduct departmental training on the new RWP system. Currently, almost all the departmental personnel were trained. The licensee also incorporated the training plan into contractor training to prevent recurrence of the incident.

The inspector concluded that the licensee's corrective actions were prompt and effective. The RWP infraction was considered a violation of Technical Specification 6.11. However, this violation is not being cited because the criteria specified in Section VII.B.1 of Appendix C to 10 CFR Part 2 were satisfied.

The inspector confirmed that the NDE examiner was qualified to perform the inspection in accordance with Procedure 1415.002, Revision 5, "Liquid Penetrant Examination." The cleaning agents and solvents required for the examination were acceptable. The weld joints passed the NDE with no defects. The system was satisfactorily returned to service.

4.6 <u>Unit 2 - Interchanging of Isolator Components in Indication Circuitry (JO 00906939)</u>

On January 10, the inspector observed the licensee interchange like for like isolator converters between the Steam Generator 2E-24A Downcomer Level Isolator 2LY-1031-4B and the Steam Generator B hot leg centerline temperature Isolator 2TY-4710-4. The licensee noted on a condition report that the Steam Generator A Level Indicator 2LI-1031-4N and associated computer point for the plant monitoring system spiked high. The spike did not affect the steam generator level input into the reactor protection trip circuitry. The licensee believed that the spike may be attributed to a defective isolator.

Since no spare isolators were on site to use in troubleshooting the indication circuitry, the isolators were interchanged to determine if Isolator 2LY-1031-4B was defective. Operations preferred to have steam generator downcomer level indication available and exchanged this isolator with an isolator from an application that had the least impact on plant operation. Neither indicating circuit was safety-related.

The licensee bypassed the necessary trip setpoints, entered the necessary action statements, and utilized a lifted lead logsheet to perform the exchange. Quality control verified the necessary holdpoints. The inspector confirmed that all individuals entered on the correct RWP. The inspector concluded that the change was acceptable, and the maintenance task was performed well.

4.7 <u>Unit 2 - Backseating of Atmospheric Dump Valve 2CV-1052 (JO 00906740)</u>

On January 13, the inspector observed the licensee backseat Atmospheric Dump Valve 2CV-1052 in accordance with a scope change to the JO package. The original JO provided instructions to torque the valve packing studs to stop a minor steam packing leak. However, the steam leak was not stopped when the valve packing studs were torqued. The valve, which was located between the main steam safety valves and the main steam isolation valve, was unisolatable from Steam Generator 2E-24B if the leak became too excessive. The scope change provided instructions to backseat the valve to verify if packing replacement was feasible at full power.

Atmospheric Dump Valve 2CV-1052 was torqued open to the full backseat position using a calibrated torque wrench and torque values provided by system engineering. The packing continued to leak after the valve was fully backseated. Since the leak did not stop while the valve was backseated, packing replacement was not possible at full power. Valve 2CV-1052 was removed from the backseat.

The licensee considered sealant injection into the valve packing, but concluded that the process may adversely affect motor-operated valve characteristics. The licensee decided that the existing leak neither adversely impacted plant operation nor personnel safety and planned to monitor the steam leak until Refueling Outage 2R10. The inspector determined that the licensee's conclusions were acceptable.

4.8 Unit 1 - Makeup Pump P-36B Seal Replacement (JO 00880612)

On January 19 through 21, the inspector observed portions of the seal replacement on Makeup Pump P-36B. The work was done according to the JO instructions and applicable procedures. The pump was aligned and recoupled. Appropriate radiological work practices were followed. The pump was tested and vibration was noted on a bearing. As a result, the licensee increased the testing frequency on this pump as required by the ASME code.

4.9 Conclusions

The licensee's program for the control of leak sealant repairs was acceptable. The procedure for controlling this type of repair was upgraded to include lessons learned from Information Notice 93-30. A leak sealant repair was successfully performed on Unit 1 emergency EFW pump turbine steam admission Valve CV-2617. Sealant injection was determined to be an inappropriate repair technique for Atmospheric Dump Valve 2CV-1052 because of the difficulty of performing motor-operated testing following sealant injection.

One noncited violation of Technical Specification 6.11 was identified when a quality control inspector signed in on an incorrect RWP. All other personnel, that were observed, complied with their RWPs. Observed maintenance activities were conducted in accordance with the Technical Specifications and appropriate procedures. Personnel performing welding and nondestructive examinations were appropriately qualified. Appropriate fire protection controls were implemented. Observed maintenance activities were appropriately prioritized.

**5 BIMONTHLY SURVEILLANCE OBSERVATION (61726)**

5.1 Unit 2 - Surveillance Testing of EDG 2K-4A (JO 009071661)

On December 12, 1993, the inspector observed surveillance testing of EDG 2K-4B per Procedure 2104.036, Revision 36, "Emergency Diesel Generator Operations," Supplement 1, "2DG1 Monthly Test." The inspector confirmed that all the Technical Specification surveillance requirements were in the procedure and that the licensee appropriately performed the procedure. The Technical Specification surveillance scheduling requirements were also satisfied. The inspector verified that the chemistry samples obtained from the fuel oil day tank and the jacket cooling water system were within the acceptance criteria established in the associated procedures. No adverse trends were identified with the collected vibration data. The diesel generator passed the surveillance, and the system was restored to service. No discrepancies were identified.

5.2 Unit 2 - Control Element Assembly (CEA) Traces (JO 00906954)

On January 7, the inspector observed the licensee's performance of CEA coil voltage measurements and functional analysis of the resultant traces. Maintenance personnel coordinated with operation's personnel to place the CEAs on the hold bus and exercised the CEAs in accordance with Procedure 2105.009, Revision 14, "CEDM Control System Operation," Supplement 2, "CEA Exercise Test." During the voltage trace functional analysis, the licensee noted that CEA 40 had a missing phase on the pull down coil. The missing phase did not adversely impact the operability of the CEA. A JR had been initiated to clean and repair items associated with that control element drive mechanism system. The work was scheduled to be performed during the upcoming refueling outage.

5.3 Unit 1 - Weekly Inverter and Load Center Check (JO 00906909)

On January 8, the inspector observed portions of the performance of Procedure 1107.001, "Electrical System Operation," Supplement 6, "Weekly Check of Inverters 4160V, 6900V, 480V AC, and 125V DC Load Centers." The operator performing the test was noted to be carefully following the procedure and was knowledgeable of the equipment being tested. No problems were identified.

5.4 Unit 2 - Plant Protection System (PPS) Channel A Test (JO 00907156)

On January 11, the inspector observed a portion of the PPS Channel A monthly surveillance test. The inspector referenced the previous surveillance test JO for PPS Channel A and confirmed that the current surveillance test satisfied the surveillance interval test schedule requirements. The inspector reviewed Procedure 2304.037, Revision 23, "Unit 2 PPS Channel A Test," and verified that the procedure satisfied Technical Specification surveillance requirements. The licensee bypassed the necessary trip setpoints and entered and exited the appropriate Technical Specification limiting condition for operation action statements within the allotted time. The personnel performing the test were qualified. While the licensee recorded voltage values displayed on the calibrated digital voltmeter into the procedure, inattention to detail by the licensee resulted in the omission of a negative sign for a recorded voltage value. The administrative error was minor and was corrected by the licensee after the discrepancy was identified by the inspector. The values were confirmed by the inspector to be within procedural tolerances. The test was stopped prior to operations shift turnover meeting in order to eliminate control room distractions, and the test was completed later. The system was properly restored to service.

5.5 Unit 2 - Core Protection Calculator (CPC) Channel A Test (JO 00907155)

On January 11, the inspector observed surveillance testing of CPC Channel A in accordance with Procedure 2312.024, Revision 3, "3205 Core Protection Calculator Channel A Test." The functional tests listed in the procedure satisfied the Technical Specification channel check requirements for departure from nucleate boiling ratio, logarithmic power, and linear power. The licensee entered and exited appropriate Technical Specification action statements. The inspector verified that redundant channels were operable during the test. The inspector's review of the licensee's logbook for CPC Channel A, which listed trends, work items and deficiencies associated with the channel. The logbook indicated that work items were successfully completed and that identified deficiencies were dispositioned promptly. No discrepancies were noted during the surveillance. The system restoration to service was complete.

5.6 Unit 1 - Channel A Reactor Protection System Testing

On February 5, the inspector observed portions of Procedure 1304.37, "Reactor Protection System Channel A Test." The inspector observed preparations made prior to performing the trip test on Channel A of the reactor protection system. These activities were critical because Channel C was inoperable and in the bypass mode. Part of the preparatory activities involved confirming that Channel C was in the bypass mode. The Channel C reactor trip breaker light was illuminated at a level that was between dim and bright. For this indication, dim meant the channel was in bypass; bright meant the channel was in trip. The instrument technician was told the channel was bypassed but observed that the light was not as dim as usual. He correctly brought the anomaly to the control room supervisor. This resulted in discovering a minor problem, another light bulb within the cabinet had burned out which resulted in a different current loading on the circuit. No problems were identified.

5.7 Conclusions

Observed surveillance tests were conducted in accordance with the procedures and within the prescribed time frames. Anomalies were identified and appropriately dispositioned. The instrument technicians' close attention to detail during Unit 1 reactor protection system testing was commendable. However, a minor inattention to detail was observed during Unit 2 PPS testing. Affective command and control was demonstrated when Unit 2 PPS testing was stopped during shift turnover. Test personnel were knowledgeable of the equipment being tested.

## 6 FOLLOWUP (92701)

6.1 (Closed) IFI 313;368/9309-04: Capability of Spent Fuel Storage Casks to withstand Fault Currents

The licensee planned to store spent fuel in a ventilated storage cask which would be installed under the 500 kilovolt transmission lines. The inspector requested documentation for review to determine if the casks were designed to withstand fault currents from a failed transmission line.

The cask vendor provided the licensee with Calculation 93-E-0078-01 which evaluated the effects of an overhead transmission line falling onto a ventilated storage cask. The vendor concluded that a transmission line falling onto the cask would have no significant nuclear, structural, or thermal effects on the cask. The inspector determined that this concern had been appropriately addressed.

6.2 (Closed) IFI 313/9310-03: Evaluation of Chemical Stains on Borated Water Storage Tank (BWST) Discharge Piping

The inspector identified chemical staining on the discharge header from the BWST. The stain was believed to have been caused when chemicals were spilled during chemical additions to the radwaste system. The primary concern was potential intergranular stress corrosion cracking related to spills of sulfuric acid. The chemical stains were evaluated by the licensee and the results documented in Licensing Information Request L93-0275. The licensee concluded that since the stains were on the elbow and not near a welded joint, it was unlikely that sulfur-induced corrosion damage occurred. The licensee liquid penetrant tested the BWST piping elbow and determined no degradation had occurred.

The chemists were instructed to avoid spilling sulfuric acid or other chemicals on the BWST piping. They were also instructed to notify their supervisor and to wash the chemicals from the affected piping if any spill occurs. The licensee was evaluating the installation of splash guards near the chemical addition pots.

## 7 ONSITE REVIEW OF LERs (92700)

(Closed) LER 368/91-015: "Inadequate Vendor Analysis of Coolant Cross Flow Resulted in the Potential for EDGs having been unable to provide Design Electrical Output for Worst Case Accident Conditions"

This LER involved a problem concerning both EDG's ability to provide design electrical load under worst case accident conditions. During an internal electrical distribution system functional inspection, the licensee identified cross flow paths between the cooling water systems for combustion inlet air and engine jacket cooling existed on both EDGs, adding additional heat burden to the air coolers and resulting in reduced generator capacity. This resulted in the plant having operated outside its design basis.

The licensee determined that the EDGs were operable at the time the condition was discovered and during previous summer conditions. EDG capacity would have been inadequate 26.6 hours into a large break loss of coolant accident if the following occurred simultaneously: (1) the temperature of the emergency cooling pond was at it's Technical Specification limit; (2) outside ambient air temperature was 113°F (design hot day); (3) normal cooling from Lake Dardanelle was lost; (4) one EDG failed; and (5) Unit 1 shutdown loads were also transferred to the emergency cooling pond. The licensee determined that the likelihood of all these events occurring was remote and, therefore, considered the condition to have little safety significance.

The licensee revised Procedure 2104.036, "Emergency Diesel Generator Operations," to require that Valves 2ED-32A and 2ED-32B be locked closed in order to isolate the cross flow path for each FDG. Since the purpose of the cross flow path was to provide warming during cold weather and the EDGs were located in a controlled environment, there were not adverse consequences from having these valves closed.

The inspector walked down and verified that these valves were locked closed. Based on the inspector's review of Procedure 2104.036 and Piping & Instrument Diagram M-2217, all corrective actions have been completed.

ATTACHMENT 1

## 1 PERSONS CONTACTED

Licensee Personnel

C. Anderson, Unit 2 Operations Manager
J. Barrett, Quality Control Inspector Supervisor
S. Bennett, Acting Licensing Supervisor
M. Bourgeois, Unit 2 Outage Manager
T. Brown, Unit 1 Outage Manager
B. Day, Unit 1 Manager
R. Fuller, Unit 1 Acting Operations Manager
M. Harris, Unit 2 Maintenance Manager
R. Howerton, Engineering Support Manager
L. Humphrey, Quality Director
T. Mitchell, Unit 2 System Engineer
R. King, Acting Licensing Director
S. Pyle, Licensing Specialist
J. Selva, Unit 1 Technical Assistant Plant Manager
J. Sutterfield, Unit 2 Operations
J. Yelverton, Vice President Operations

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

## 2 EXIT MEETING

An exit meeting was conducted on February 8, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors. The licensee acknowledged the inspection findings and did not express a position on these findings.

A telephone conversation was held with licensee personnel on March 30, 1994, to inform them of the inclusion of Violation 313/9311-01, Examples 1 and 2, in the report. These issues had been previously reviewed with the licensee, but had not been identified as enforcement issues. These personnel acknowledged the identified violations and did not express a position.

ATTACHMENT 2

**ACRONYMS**

| | |
|---|---|
| ASME | American Society of Mechanical Engineers |
| BWST | borated water storage tank |
| CEA | control element assembly |
| COLSS | core operating limiting supervisory system |
| CPC | core protection calculator |
| CRD | control rod drive |
| EDG | emergency diesel generator |
| EFW | emergency feedwater |
| ETA | ethanolamine |
| IFI | inspection followup item |
| JO | job order |
| JR | job requests |
| LER | licensee event report |
| M&TE | measuring and test equipment |
| NDE | non-destructive examination |
| OTSG | once through steam generator |
| P&ID | piping and instrument diagram |
| PPS | plant protection system |
| RWP | radiation work permit |