ENCLOSURE 2

Inspection Report: 50-313/95-09
50-368/95-09

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: October 29 through December 9, 1995

Inspectors: K. M. Kennedy, Senior Resident Inspector
S. J. Campbell, Resident Inspector
J. F. Melfi, Resident Inspector

Approved: Terence Reis
T. Reis, Acting Chief, Project Branch C

1-10-96
Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced inspection of onsite review of an event, operational safety verification, maintenance and surveillance observations, plant support activities, followup - operations, followup - maintenance, and onsite review of licensee event reports (LERs).

Results (Units 1 and 2):

Plant Operations

- The inspectors confirmed that the licensee met the minimum Technical Specification (TS) requirements while Unit 2 was in Mode 5 (Section 2.1).

- The licensee's failure to classify temporary hoses attached to the service water (SW) drains on the Unit 2 shutdown cooling (SDC) heat exchangers as a temporary modification and utilize the controls specified in the temporary modification procedure was identified as a violation. The violation occurred because the temporary modification procedure provided conflicting guidance for installing drain hoses and mechanical jumpers. The licensee addressed the violation by writing instructions to install, operate, and remove the temporary system in the SW operating procedure (Section 2.3).

- Unit 2 operators performed well during the filling and venting of the reactor coolant system, the reactor startup conducted at the end of Refueling Outage 2R11, and the reactor shutdown to repair a component cooling water (CCW) leak inside containment. Prejob briefs were thorough, potential problems were appropriately considered and discussed, communications were clear and effective, and support to operations from other organizations was good (Sections 2.3, 2.4, and 2.7).

- The inspectors noted an improvement in the effectiveness of the licensee's inspections of the Unit 2 containment building following the completion of outage activities and prior to plant heatup (Section 2.4).

- The outage action plan developed for the repair of Unit 2 Main Feedwater Pump A was a good tool which provided licensee personnel with a clear understanding of the outage plans and activities (Section 2.6).

- A walkdown of the Unit 1 emergency feedwater system revealed that valves were properly aligned and that the system appeared to be in good material condition (Section 2.8).

Maintenance

- Maintenance activities, including the repair of Unit 1 SW Pump C and the repair of the Unit 2 reactor coolant system pressure boundary leakage were conducted in accordance with procedures, radiological work practices were appropriate, and system engineering and quality control personnel involvement in the activities was appropriate (Sections 3.2 and 3.3).

- Instrumentation and controls technicians were knowledgeable and demonstrated good communications during the conduct of reactor coolant resistance temperature detector response time testing (Section 4.2).

Engineering

- The inspectors identified differences in the safety evaluation and the procedure change for installing a temporary system on the SDC heat exchanger SW drains. The safety evaluation did not fully consider the impact of routing hoses through high pressure safety injection (HPSI) pump room watertight doors in the event flooding occurred in the room although the procedure change did. Additionally, the safety evaluation permitted draining the SW from the SDC heat exchangers in any operational mode, whereas the procedure change restricted draining in Modes 4, 5, and 6 or defueled condition. The inspectors concluded that the plant safety committee appropriately identified potential impacts not addressed in the safety evaluation prior to issuing the procedure change (Section 2.3).

Plant Support

- Radiological work practices observed during the performance of maintenance activities and routine plant tours were appropriate (Section 3).

Summary of Inspection Findings:

New Items

- One violation was identified (Section 2.3).

Closed Items

- Unresolved Item 368/9517-01 (Section 6)
- Violation 313/9310-02 (Section 7.1)
- Inspection Followup Item 313/9406-06 (Section 7.2)
- LERs 313;368/95-003 and 313/95-005 (Section 8)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On November 3, 1995, operators reduced power to 88.5 percent to perform routine turbine valve and governor valve testing and returned to 100 percent power on November 4. On November 16, operators reduced power to approximately 94 percent for a condenser tube repair, returning to 100 percent power the same day. On November 26 and 27, operators reduced power to 90 percent and 98 percent, respectively, due to condenser tube fouling concerns. Power was restored to 100 percent after each downpower. On December 8, operators reduced power to 88.5 percent to perform routine turbine valve and governor valve testing, returning to 100 percent power on December 9. Unit 1 remained at 100 percent power through the end of the inspection period.

1.2 Unit 2

Unit 2 started the inspection period in Refueling Outage 2R11. On November 20, 1995, operators placed the plant in Mode 1 and synchronized the main generator to the grid. On November 22, with the plant at 29 percent power, operators commenced a downpower and entered Mode 2 to repair a hydrogen leak on the main generator. On November 26, Main Feed Pump A seized while on the turning gear. The licensee determined that a failure had occurred in the feed pump turbine and removed the turbine for repair. On November 30, operators entered Mode 1 and completed a power escalation to 79 percent on December 3. On December 5, operators decreased power and entered Mode 2 to reinstall the repaired Main Feedwater Pump A turbine. While in Mode 2, the licensee discovered that a previously identified CCW leak inside containment required that Reactor Coolant Pump (RCP) B be secured to repair the leak. The licensee conducted a normal reactor shutdown and entered Mode 3 on December 5. After completing the repairs to Main Feed Pump A and CCW, the licensee conducted a reactor startup and entered Mode 1 on December 6. Operators escalated power to 97.5 percent and the plant remained at that power level through the end of the inspection period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

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

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. An

independent verification of the status of safety systems, a review of Technical Specification (TS) limiting conditions for operation, and a review of facility records were also performed.

2.1 Unit 2 - Verification of Mode 5 TS Requirements

On November 11, 1995, the inspectors verified that Mode 5 TS requirements were satisfied by conducting plant and control room control board walkdowns. The verified TSs included:

- TS 3.1.1.2 - Shutdown Margin
- TS 3.1.1.3 - Reactor Coolant System (RCS) Flowrate
- TS 3.1.2.1 - Boric Acid Makeup Flowpath
- TS 3.1.2.3 - Operable Charging Pump
- TS 3.1.2.5 - Operable Boric Acid Makeup Pump
- TS 3.1.2.7 - Operable Borated Water Source
- TS 3.1.3.3 - Operable Reed Switch Position Transmitter Channel
- TS 3.4.1.3 - Operable RCS Loops
- TS 3.8.1.2 - Operable AC Power Sources
- TS 3.8.2.2 - Operable AC Electrical Buses
- TS 3.8.2.4 - Operable DC Electrical Equipment

The inspectors confirmed that the licensee met these minimum TS requirements while the unit was in Mode 5.

2.2 Unit 2 - Filling and Venting the RCS

On November 12, 1995, the inspectors observed operators fill the RCS from a level of 26 inches to a level of 90 inches above the bottom of the hot leg in accordance with Procedure 2103.002, Revision 33, "Filling and Venting the RCS." The operators filled the RCS after the steam generator tube inspections were completed.

The inspectors attended the pre-evolution brief and noted that the operators reviewed RCS filling and venting procedure requirements, discussed the operator duties, and stressed the importance of clear communication during the evolution. To prevent leakage of oxygen scavenging chemicals into the containment building, the operators decided to add the chemicals into the RCS after it was determined that the steam generator manways were not leaking. Additionally, the operators noted that a leaking manway was a termination criterion for filling and venting. The inspectors found that the licensee appropriately considered potential problems that could have been encountered during the evolution and concluded that the brief was thorough.

The operators verified that the RCS vent valves were appropriately aligned for venting to the containment building atmosphere in accordance with the procedure and started a charging pump to begin filling the RCS. During the fill, the inspectors noted that communication in the control room was clear and distinct and that the noise level remained low. The operators repeated commands given by the control room supervisor and used self-checking

techniques prior to manipulation of plant controls. The operators remained focused at their assigned work stations and closely monitored critical plant parameters (RCS level, SDC flow, RCS heatup rate, time to boil, and time to core uncovery.) The licensee added oxygen scavenging chemicals to the RCS after they determined that the steam generator manway did not leak and completed filling the RCS to 90 inches without difficulty. The inspectors concluded that the licensee performed the filling and venting evolution well.

2.3 Unit 2 - Lack of a Temporary Modification for Connecting SDC Heat Exchanger SW Drains

On November 13, 1995, while touring Elevation 317 of the Unit 2 auxiliary building, the inspectors noted that hoses and a pump were connected to the SW drain valves on SDC Heat Exchangers 2E-35A and -35B. SW supplies cooling to SDC Heat Exchangers 2E-35A and -35B, and the drain valves, when opened, drain SW from the shell side of the heat exchangers. The hoses were routed through open HPSI Pump Rooms A and B watertight doors and were connected to a pump staged outside the rooms. The licensee planned to use the temporary system to drain SW from SDC Heat Exchanger 2E-35B to SDC Heat Exchanger 2E-35A in order to repair leaking SDC Heat Exchanger 2E-35B Inlet Valve 2CV-1456-2 when the plant reached Mode 4. At the time of the inspectors' observation, the plant was in Mode 5, with SDC Heat Exchanger 2E-35A in operation to remove decay heat from the RCS. The inspectors noted that the SW drain valves were closed with hold cards attached, thus isolating the temporary hoses from the SDC heat exchangers. However, the inspectors also noted that the hoses and the pump did not have temporary modification tags attached to them. The inspectors asked the licensee if the temporary system was a temporary modification that required a 10 CFR 50.59 safety evaluation.

In response to the inspectors' question, the licensee reviewed Procedure 1000.028, Revision 17, "Temporary Modification," to determine if the temporary system was a temporary modification. The licensee found that Step 2.2.5 excluded temporary hoses attached to drains as temporary modifications. As a result, when Job Order (JO) 00940236 instructions were written to install and operate the temporary system, they did not consider the temporary system as a temporary modification. However, upon further review of the procedure, the licensee identified that Step 4.1 indicated that the use of mechanical jumpers (cross-tieing safety systems using hoses) as a temporary alteration to safety-related equipment, which did not conform to approved drawings or design documents, was a temporary modification. The licensee concluded that the conflicting guidance provided in the procedure for the use of drain hoses and mechanical jumpers was the root cause for not initially considering the connected hose as a temporary modification. They found that the intent of procedure Step 2.2.5 was for installing drain hoses routed to drain collection points (such as sumps) and not for cross-tieing systems. Condition Report 2-95-0514 was initiated to document the failure to classify the temporary system as a temporary modification.

As part of their immediate corrective action, the licensee changed Procedure 2104.029, Revision 41, "Service Water System Operation," to

incorporate instructions for installing, operating, and removing the temporary hoses and pump. The inspectors reviewed the procedure change and the 10 CFR 50.59 safety evaluation, which accompanied the procedure change, and noted the following differences:

- The safety evaluation stated that the procedure change allowed for draining SW from the SDC heat exchangers when the plant was in any operational mode. However, the inspectors noted that the procedure change allowed for draining only in Modes 4, 5, and 6 or defueled condition and questioned why the mode requirements for draining were different than allowed by the safety evaluation. The licensee stated that the plant safety committee restricted draining in Modes 1- 3 because the containment spray and the emergency core cooling systems would be declared inoperable. However, draining in Modes 4 - 6 and defueled condition would not require these components to be declared inoperable and considered draining in these modes to be more conservative.

- The safety evaluation credited the use of a dedicated operator to close the SW drain valves to prevent HPSI room flooding if a hose failed, but the evaluation did not address closing the HPSI room watertight doors in the event of flooding in the room from other sources. The Unit 2 Safety Analysis Report credited closing the watertight doors to keep redundant components in other HPSI rooms operable if flooding occurred. The safety evaluation did not address an event, other than a hose failure, which may require removing the hoses so that the watertight doors may be closed. However, before the change was implemented, the plant safety committee recognized that the water tight doors were required to be closed in the event of flooding in the room and included a note in the procedure change for the dedicated operator to remove the hoses and close the watertight doors if flooding occurred in the rooms.

The inspectors concluded that the plant safety committee appropriately identified potential concerns not addressed in the safety evaluation and issued a procedure change that addressed these concerns. The inspectors determined that the differences between the safety evaluation and the final procedure change were not significant and that the procedure change was more conservative than the safety evaluation.

The licensee also planned to review the temporary modification procedure to determine if the requirements for temporary modifications could be clarified.

The inspectors reviewed JO 00940236 and found that it allowed the SDC heat exchanger to be drained in any mode, at the discretion of the operators, and that it did not require a dedicated operator to be present to close watertight doors in the event of flooding. However, the inspectors confirmed that the licensee had annunciator corrective action procedures to close the watertight doors in the event of flooding in the rooms.

The inspectors determined that the licensee failed to identify the hoses and pump connected to the SDC heat exchangers as a temporary modification as defined by Procedure 1000.028, paragraph 4.1, and, therefore, did not apply the appropriate controls. This was determined to be a violation of TS 6.8.1.a (368/9509-01). This violation occurred because the temporary modification procedure provided conflicting guidance on the use of hoses on system drains and as mechanical jumpers.

2.4 Unit 2 - Walkdown of the Unit 2 Containment

On November 14, 1995, the inspectors toured Unit 2 containment prior to the operators performing a plant heatup. This tour was conducted following the licensee's own preheatup containment walkdown. Although the inspectors identified several loose items inside containment, none were significant and the licensee took prompt action to resolve the inspectors' concerns. In addition, the inspectors noted fewer discrepancies during this walkdown as compared to previous inspector walkdowns performed after the licensee had conducted their own.

During the walkdown of containment, the inspectors identified two large metal enclosures on the missile shield which did not appear to be secured. The licensee indicated that these were lead boxes which were part of an abandoned in-core detection drive machine. Subsequent to questioning by the inspector, the licensee completed an evaluation which concluded, based on the weight of the boxes and the seismic forces, that the boxes would not slide during a seismic event. The inspectors reviewed the licensee's evaluation and agreed with their assessment. The licensee was also evaluating a plant change to install positive supports for the boxes.

2.5 Unit 2 - Startup from Refueling Outage 2R11

On November 19, 1995, the inspectors observed initial reactor startup activities following completion of Refueling Outage 2R11. Operators used Procedures 2302.022, "Initial Criticality Following Refueling," and 2102.016, "Reactor Startup," to control their activities. The approach to criticality was well controlled, with operators and reactor engineers observing the source range monitors. The licensee's estimated critical position was with the last bank of rods at 105.5 inches. The reactor did not go critical at 105.5 inches or with all rods out, but the all-rods-out position was within the error allowed by the procedure ($\pm$ 0.5% $\Delta K/K$). Following Procedure 2101.016, operators then inserted the last bank of rods to 100 inches and diluted the RCS boron to achieve criticality. The RCS boron concentration was diluted 23 ppm to 1642 ppm boron, which was within the 0.5% $\Delta K/K$ allowed by the licensee's procedure. The inspectors concluded that the approach to criticality was well controlled and that control room communications were good.

2.6 Unit 2 - Failure of Main Feedwater Pump A Turbine and Subsequent Restoration

On November 26, 1995, with the plant in Mode 2 and reactor power at approximately 1 percent, Main Feedwater Pump A seized while on the turning gear. The licensee determined that the problem was with the turbine. Upon disassembling the turbine, the licensee discovered that a bolt cover ring on the low pressure nozzle plate had come loose and become wedged between the rotating turbine and the stationary nozzle block. In addition to the damaged bolt cover ring, the first stage turbine wheel was scored. The licensee removed the turbine rotor and sent it offsite for refurbishment. Operators restored the plant to 79 percent power on December 3.

The licensee determined that a fastener which held the bolt ring in place had failed, allowing the bolt ring to come out of a groove and become lodged against the turbine rotor. It was observed that a similar bolt ring on the inner diameter of the nozzle plate was tack welded at a number of locations around the circumference of the cover.

On December 5, with the refurbished turbine reinstalled, the licensee decreased reactor power to approximately 1 percent and broke condenser vacuum to allow the removal of a blank flange installed in the main feedwater pump turbine exhaust trunk.

Prior to decreasing power to reinstall the main feedwater pump turbine, the licensee developed an outage action plan to define the scope of the outage, assign personnel from different departments for outage coverage, and provide a detailed schedule of events. The plan provided an overall summary of events and considered the impact of the activities on Unit 1. In addition, a separate plan was developed for secondary chemistry control during the power maneuvers. The inspectors determined that the outage action plan was a good tool which provided licensee personnel with a clear understanding of the outage plans.

2.7 Unit 2 - Plant Shutdown to Repair CCW Leak

On December 5, 1995, Unit 2 operators decreased power and entered Mode 2 to reinstall the repaired Main Feedwater Pump A turbine. While in Mode 2, the licensee determined that a previously identified CCW leak inside containment was coming from the CCW return line from RCP B. Since the pump would have to be secured to make the repairs, the licensee conducted a normal plant shutdown to Mode 3. The inspectors observed the prejob brief and the plant shutdown from the control room. During the prejob brief, the operators discovered that Procedure 2103.006, Revision 11, "Reactor Coolant Pump Operations," did not allow CCW to be secured to the RCP until RCS temperature was below 175°F and pressure was less than 200 psig. Since the licensee was not going to cool down or depressurize the plant and CCW needed to be secured to the RCP, a temporary procedure change was initiated to allow CCW to be secured to the RCP motor cooler. The supply of CCW to the RCP seals would be maintained.

The inspectors observed as the operators performed the plant shutdown in accordance with Procedure 2102.004, "Power Operation." The inspectors noted that the shutdown was orderly and conducted in accordance with procedures. A reactor engineer was present to calculate shutdown margin and system engineering was tasked with monitoring RCP temperatures and informing operations when it was acceptable to secure CCW to the RCP motor.

The inspectors concluded that the identification during the brief prior to the reactor shutdown of the need for a procedure change to secure CCW to the RCP motor was good. The plant shutdown was well controlled and engineering support for the shutdown was good.

2.8 Unit 1 - Emergency Feedwater System Walkdown

On November 28, 1995, the inspectors conducted a walkdown of the Unit 1 emergency feedwater system and found that valves were properly aligned and the system appeared to be in good material condition. The inspectors did observe that an emergency feedwater isolation valve had a tag attached which stated, "Caution, Remove Temporary Packing Before Operating." The inspectors discussed this with the system engineer who confirmed that the tag was left hanging in error and that the correct packing was installed in the valve. The licensee removed the tag.

3 MAINTENANCE OBSERVATIONS (62703)

3.1 Units 1 and 2 - Maintenance Observations

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

- JO 00940134, "Buffer Amplifier Changeout on Engineered Safeguards Channel 3," on November 9, 1995.

- JO 00940386 "To Reassemble SW Pump P-4C on November 9.

- JO 00940714, "Leak From Valve Body to Bonnet on 2CV-4651, RCS Pressurizer Spray Valve," on November 17.

- JO 00940717, "Blind Flange Leak Above Pressurizer," on November 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 in the following paragraphs:

3.2 Unit 1 - Ground on SW Pump P-4C

On November 9, 1995, the inspectors observed a portion of the performance of JO 00940386 to replace a worn pump shaft sleeve and the packing around the shaft sleeve. The shaft sleeve was worn because the packing was extruded from under the packing follower and caused nonuniform water lubrication. The water flows between the shaft and the packing to lubricate the shaft. The licensee speculated that the extruded packing was the result of inadequate packing adjustment during pump installation in May 1995 and had initiated a condition report to determine the root cause of the worn shaft. The inspectors concluded that the repair activities were conducted appropriately and personnel followed procedures and used the proper equipment. The motor leads were reconnected using JO 00940404.

Following completion of this maintenance activity, the licensee uncoupled and ran the motor. After the uncoupled run, the licensee coupled the pump and motor, started the pump, and approximately 1 hour after starting Pump P-4C to conduct a surveillance test, SW Pump Supply Breaker A-402 tripped due to a ground on the Phase B. The licensee initiated Condition Report 1-95-0628 and determined that the fault was located in the cable run from the breaker to the motor. The licensee determined which section of cable had the fault and replaced approximately 300 feet of cable for each phase using Plant Change 95-7098. The pump was successfully tested on November 20.

The inspectors noted that system engineering was actively involved in determining the location of the fault and developing the plant change to replace the cable.

3.3 Unit 2 - Repair of Reactor Coolant Pressure Boundary Leaks

Following the completion of Refueling Outage 2R11 maintenance activities, the licensee conducted a plant heatup to the normal operating temperature and pressure for the RCS. While at the normal operating temperature and pressure, the licensee identified several leaks from RCS components located inside containment which required repair. Operators cooled down and depressurized the RCS in order to repair these leaks. The inspector observed portions of the following JOs on November 17, 1995:

- JO 00940714, "Leak from Valve Body to Bonnet on 2CV-4651, RCS Pressurizer Spray Valve"

- JO 00940717, "Blind Flange Leak Above Pressurizer"

The components leaked because the gaskets had not been replaced through several cycles of operation and were old and worn. The licensee replaced the gaskets and reassembled the components. The inspector observed that the maintenance activities were conducted in accordance with procedures and that radiological work practices were appropriate. The inspectors noted appropriate involvement in the maintenance activities by quality control personnel and system engineers. The work was completed satisfactorily.

4 SURVEILLANCE OBSERVATIONS (61726)

4.1 Units 1 and 2 - Surveillance Test Observations

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

- Unit 1 - Procedure 1104.004, "Decay Heat Removal Operating Procedure," Supplement 1, "Low Pressure Injection (Decay Heat) Pump (P-34A) & Components Quarterly Test," on November 16, 1995.

- Unit 2 - Procedure 2304.045, "Unit 2 Reactor Coolant RTD Response Time Test," on November 15.

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

4.2 Unit 2 - Reactor Coolant Resistance Temperature Detector (RTD) Response Time Test

On November 15, 1995, the inspectors observed instrumentation and controls technicians perform portions of Procedure 2304.045, "Unit 2 Reactor Coolant RTD Response Time Test." This surveillance was performed with the plant in Mode 3 and was performed to assess conformance with TS 4.3.1.1.3. The inspectors found that the technicians were knowledgeable of the test equipment, the test setup, and the procedure. The test was performed in accordance with the test procedure, the recording of test data was accurate, and the technicians communicated well with each other and with the control room operators. Because the surveillance tested 24 RTDs and was scheduled to be performed over a 24 hour period, control room operators performed well in coordinating other plant activities conducted during the performance of the response time testing.

5 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.

6 FOLLOWUP - OPERATIONS (92901)

(Closed) Unresolved Item 368/9517-01: Excessive Duplication of Written Examination Questions in Successive Examinations

This unresolved item identified the practice of requiring only a change of 30 percent in examination content from examination to examination, including retake examinations. The Office of Nuclear Reactor Regulation was requested to determine if a violation had occurred and provided guidance concerning the acceptable level of question duplication in the development of written requalification and retake examinations.

The Office of Nuclear Reactor Regulation has determined that no violation occurred; however, concern was expressed that continued allowance of up to 70 percent question duplication could compromise the exams and result in a violation of 10 CFR 55.49. The licensee has indicated it will revise its internal procedures to restrict the exam question duplication rate to 30 percent. The acceptable standard for question duplication is 50 percent.

7 FOLLOWUP - MAINTENANCE (92902)

7.1 (Closed) Violation 313/9310-02: Failure to Replace Critical System Relays on Switchboards

This violation involved the failure to replace critical system relays for safety-related inverters within the replacement frequency as specified in Preventive Maintenance Engineering Evaluation (PMEE) 107. The failure to replace the relays within the replacement frequency resulted in age-related degradation of vital Inverters Y-11 and -13 transfer switches, which was identified in November 1993. The degraded relays resulted in an unsuccessful manual transfer of electrical power from the alternate to the normal source. To prevent age related degradation of these relays from adversely impacting inverter operation, PMEE 107 recommended that the relays on the oscillator, syncronization, and status switch boards for the inverters be replaced once per refueling outage. The inspectors found that the PMEE requirements were not implemented into preventive maintenance tasks for safety-related inverters and, as a result, these critical system relays were not replaced during Refueling Outage 1R11 which ended October 18, 1993.

The licensee wrote Condition Report C-94-0001 to document that PMEE requirements were not implemented into the preventive maintenance tasks. The licensee proposed and closed condition report corrective actions, which included incorporating the PMEE requirements into Units 1 and 2 repetitive and preventive maintenance tasks and developing processes and training to ensure

PMEE requirements will be incorporated into these tasks. The inspectors reviewed the corrective actions and found them to be comprehensive. This violation is closed.

7.2 (Closed) Inspection Followup Item 313/9406-06: Slow Start of Emergency Diesel Generator (EDG) K-4B

This item was opened after the north bank of air start motors failed to start EDG K-4B within the normal start time of 10.5 seconds, which was discovered during routine EDG surveillance testing. During the surveillance test, the north bank of air start motors received a start signal and the air start motor's pinion gear teeth were supposed to move into and mesh with the EDG flywheel teeth and spin the flywheel to the required revolution to start the EDG. When the north bank of air start motors did not start the EDG within the normal start time, the south bank of air start motors started the EDG after a 2.5-second time delay. The 2.5-second delay was due to a swapping relay that actuates the other air bank if the flywheel speed is low. The EDG achieved rated voltage and frequency in 13.02 seconds, which was within the TS-required 15 seconds. The licensee wrote Condition Report 1-94-0212 to document the failure of the north bank of the air start motor to start the EDG within the normal 15-second start time.

During the root cause evaluation, the licensee found that the north bank of air start motor pinion gear teeth abutted against the flywheel teeth, which prevented the start motor from engaging and meshing with the EDG flywheel. The inspectors opened this inspection item to assess the effect pinion gear abutment had on EDG start times and the associated single failure analysis.

The licensee contacted the EDG vendor to determine if pinion gear teeth abutment was a common occurrence while starting the EDG and found that pinion gear abutment was a normal, but infrequent, design phenomena of the system. The design of the air start motor requires that the pinion gear teeth withdraw, slightly rotate, and re-engage into the flywheel if the initial engagement was unsuccessful. This design feature would ensure that the air start motor pinion gear teeth would engage on the second attempt. The licensee concluded that the north bank of air start motors operated as designed because the south bank of air start motors engaged the EDG flywheel before the north bank of air start motors could re-engage. The inspectors determined that the worst case scenario was the failure of both banks of air start motors to engage on the first attempt. The inspectors concluded that the air start system had sufficient redundancy to prevent a single failure of an EDG to start due to pinion gear abutment and that the north and south bank of air start motors had functioned as designed.

Additionally, the licensee researched surveillance test data for EDG starts over the past 3 years to determine if the EDG had previously exceeded the normal start time and found that the EDG had always started within the normal start time. The inspectors concluded that the possibility of exceeding the TS start time requirement, due to pinion gear abutment, was remote because the

EDG airstart design provided sufficient design redundancy and that the historical data indicated pinion gear abutment was not a repetitive occurrence. This item is closed.

8 IN-OFFICE REVIEW OF LERs (90712)

The following LERs were closed based on an in-office review of each 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;368/95-003, "Failure to Collect the Required Number of Radiological Environmental Milk Samples Due to Incorrect Interpretation of TS Requirements."

- LER 313/95-005, "Reactor Trip Initiated by Main Turbine Generator Protective Circuitry as a Result of a Logic Circuit Ground Caused by Vibration Induced Insulation Wear."

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

M. Cooper, Licensing Specialist
S. Cotton, Training Manager
D. Denton, Support Director
B. Eaton, Unit 2 Plant Manager
R. Edington, Unit 1 Plant Manager
R. Espolt, Events Analysis and Assessment Manager
R. Fuller, Unit 1 Operations Assistant Manager
D. Higgins, Unit 1 Maintenance Assistant Manager
R. Lane, Design Engineering Director
C. Little, Design Engineering
D. McKinney, Unit 2 Assistant Operations Manager
J. McWilliams, Modifications
D. Mims, Licensing Director
T. Mitchell, Unit 2 System Manager
D. Provencher, Quality Coordinator
B. Short, Licensing Specialist
M. Smith, Licensing Supervisor
H. Williams, Jr., Security Superintendent
A. Wrape, Unit 1 System Engineering 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 December 12, 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.