APPENDIX

U. S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/90-02 Licenses: DPR-51
50-368/90-02 NPF-6

Dockets: 50-313
50-368

Licensee: Arkansas Power & Light Company (AP&L)
P.O. Box 551
Little Rock, Arkansas 72203

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

Inspection At: ANO Site, Russellville, Arkansas

Inspection Conducted: January 1-31, 1990

Inspectors: C. C. Warren, Senior Resident Inspector
Project Section A, Division of Reactor Projects

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D. D. Chamberlain, Chief, Project Section A Date
Section A, Division of Reactor Projects

Inspection Summary

Inspection Conducted January 1-31, 1990 (Report 50-313/90-02; 50-368/90-02)

Areas Inspected: Areas examined during the inspection included followup of previously identified items, followup of events, operational safety verification, surveillance, maintenance, and in-office review of licensee reports.

Results: Section 4.4 of this report discusses a licensee identified problem regarding calculation errors associated with calibration of steam generator level instruments. This resulted in a procedural violation for which no Notice of Violation was issued in accordance with NRC Enforcement Policy. Licensee actions were considered aggressive and appropriate for this problem.

An Unresolved Item 368/9002-01 is addressed in Section 4.1 regarding the adequacy of licensee administrative controls for operator use of uncontrolled information and deviation from procedures. Two inspector followup items have also been opened in this inspection period: 368/9002-05 concerns resolution of an inaccurate service water pump runout value in the FSAR (Section 5.1) and 368/9002-02 addresses licensee corrective actions for two instances where hoses became inadvertently entrained in a service water pump (Section 4.5).

Weaknesses: Operator use of uncontrolled information for performance of work and the practice of deviating from approved operating procedures to compensate for equipment problems were areas of concern to the inspectors (Section 4.1). The large number of late condition reports with a significant number of action items greater than 60 days late has the potential to overwhelm the condition reporting system and allow further delay of corrective action resolutions. Management attention is needed to reduce the backlog of late items (Section 3.2).

Strengths: Licensee management's decision to delay restart of Unit 2 to perform various maintenance items not critical to the restart shows a willingness to address material conditions of the plant as the top priority.

DETAILS

1.0 Persons Contacted

*N. Carns, Director Nuclear Operations
*T. Baker, Technical Assistant to Plant Manager, Central
*D. Boyd, Nuclear Safety and Licensing Specialist
K. Coates, Unit 1 Maintenance Manager
A. Cox, Unit 1 Operations Manager
R. Eddington, Unit 2 Operations Manager
*E. Ewing, General Manager, Technical Support and Assessment
*R. Fenech, Unit 2 Plant Manager
*J. Fisicaro, Licensing Manager
*C. Fite, Supervisor, In-House Events Assessment
*L. Humphrey, General Manager, Nuclear Quality
J. Jacks, Nuclear Safety and Licensing Specialist
R. King, Plant Licensing Supervisor
J. Kowalewski, Mechanical Engineer
*R. Lane, Manager, Engineering Standards and Programs
A. Sessoms, Plant Manager Central
*J. Vandergrift, Unit 1 Plant Manager
J. Waxenfelter, Unit 2 Maintenance Manager
*K. Wire, Manager, Plant Assessment

*Present at exit interview.

The inspectors also contacted other plant personnel, including operators, engineers, technicians, and administrative personnel.

2.0 Plant Status (Units 1 and 2)

Unit 1 operated at 80 percent power January 1-9, 1990, at which time reactor power was reduced to a low of 3 percent and the turbine was taken offline. This was performed to allow replacement of o-rings in the actuators of the turbine governor valves and to allow testing of the governor valve sequencing circuitry (Section 4.3). On January 11, 1990, the unit reached 80 percent power and remained at that power level through the remainder of the inspection report.

Unit 2 remained shut down from January 1, 1990, until the unit went critical on January 6, 1990. The shutdown resulted from a reactor trip on December 31, 1989, that was due to a feedwater transient (Section 4.2). January 10-16, 1990, the unit operated at approximately 90 percent power due to portions of the feedwater control system being in manual and due to problems with the auxiliary building ventilation system. On January 17, 1990, the unit reached 100 percent power and remained at that power through the remainder of the inspection period.

3.0 Followup on Previously Identified Items (Units 1 and 2) (92701 and 92702)

3.1 (Closed) Unresolved Item (368/8910-02): Permanent resolution of a containment isolation valve stroke test time deficiency.

An adjustment was made on Component Cooling Water Valve 2CV-5236-1 (a containment isolation valve) to limit the valve travel to approximately 90 percent open so that the valve would pass the stroke time test. Based on a lack of any additional hardware or procedural controls to ensure that 90 percent of valve travel was maintained it appeared to the inspector that the adjustment should be considered a temporary condition. During the recent Unit 2 refueling outage, the operator for Valve 2CV-5236-1 and a similar Electro-Dyne operator on Valve 2CV-5255-1 were replaced with Limitorque operators. The inspectors have not identified any other examples of the licensee not implementing the temporary modification process when making temporary changes in the plant. Therefore, the adjustment of 2CV-5236 without a temporary modification appears to be an isolated case. This item is closed.

3.2 (Open) Inspector Followup Item (368/8930-01): Failure of a high pressure safety injection (HPSI) stop check valve to reseat.

During an HPSI system surveillance, reverse rotation of the idle "B" HPSI pump was observed. Back leakage through the pump's discharge stop check valve (2SI-10B) was the cause of the reverse rotation. The licensee completed a temporary repair of the valve during the recent refueling outage. An 18-month operability determination was made to allow continued use of the valve until the next refueling outage. The licensee has initiated "long-term" corrective action for permanent replacement of the valve. Inspector followup item (IFI) 368/8940-05 was assigned to track the "long-term" corrective action in NRC Inspection Report 50-368/89-40.

Condition Report (CR) 2-89-0326 was used to document 2SI-10B backleakage and the resulting correction action. Action item No. 3 of the CR was assigned to engineering on August 29, 1989, to evaluate the effects of the reverse rotation experienced by the "B" HPSI pump and any potential damage to the suction piping due to overpressurization. The original response due date was October 1, 1989, and then later extended to November 1, 1989. During followup of this item on January 25, 1990, the inspector noted that this action item had not been answered. In addition, the inspector learned that the engineer assigned to this action item was no longer in the nuclear engineering organization.

After further questioning the inspector learned that as of January 25, 1990, there were 368 CR action item responses that were late with 135 of the responses being late by greater than 60 days. A review of CR action item trends indicates that the overall number of late action items has significantly increased since September 1989 with only a small decrease in January 1990. The inspector expressed his concern to licensee's management that with the large number of late CR action items, the monthly reviews of late action items by the responsible managers may be ineffective in prioritizing and identifying any critical late items. This concern was again expressed in the exit meeting. Licensee management stated the intent to review the overall backlog for any critical action items needing a timely response and to implement appropriate action to reduce the backlog of late action items. The inspector will continue to monitor the licensee's actions concerning late CR action items.

3.3 (Closed) Inspector Followup Item (313;368/8918-02): Applicability review of technical manual (TM) revisions.

The licensee has revised administrative procedure to require a technical review of TM revisions to determine if applicable plant procedures need a corresponding change. The current review of TM revisions is performed in an expeditious manner versus previous reviews that may not have been performed until the biennial procedure review. The inspector also reviewed the program that the licensee has implemented for the tracking and documenting of these applicability reviews. This item is closed.

3.4 (Closed) Deviation (313/8810-01): Failure to take action as committed in response to a violation.

In a violation response the licensee had committed to establish a specific convention for valve positions as shown on Piping and Instrumentation Diagrams (P&IDs) and incorporate this into procedures by December 31, 1987. A deviation was imposed in April 1988, due to the licensee not having established a convention for depicting valve position on P&IDs.

Currently, valve positions as depicted on P&IDs are typical for valve lineups during start up operation. This convention has been documented in operational administrative procedures and on individual P&IDs. The licensee has completed a review of Units 1 and 2 P&IDs by comparing valve positions as indicated in operational procedures to the P&ID valve positions. Discrepancies in P&IDs were corrected. Instructions are also included in operational procedures to ensure that P&IDs are changed to reflect any changes to valve position as shown on valve lineup sheets. The inspector concluded that the licensee has adequately addressed this issue. This item is closed.

3.5 (Open) Violation (313/8828-01): Failure to implement timely corrective action for reactor coolant system (RCS) unidentified leakage event.

Operation Procedure 1103.13, "RCS Leak Detection," was revised to incorporate the pumping of the reactor coolant pump seal leakage collection tank into the quench tank when the quench tank fill rate is being calculated. The inspectors have noted that increased operations and management attention have been recently given to RCS leak rate trends and increases. This increased attention appears to be a result of recent RCS leaks and an increase in the safety awareness of management and the operations staff.

While reviewing Procedure 1103.13, the inspector did note the absence of a Technical Specification (TS) leakage criteria. TS 3.1.6.1 limits total RCS leakage to 10 gpm. In addition, TS 3.1.6.8 states that RCS leakage that can be returned to RCS shall not be included in the total RCS leakage, with the exception that such losses when added to total leakage shall not exceed 30 gpm. Supplement 1 (RCS Leak Rate Determination) of Procedure 1103.13 included the 30 gpm limit but not the 10 gpm total RCS leakage limit in the "Acceptance Criteria Table," nor is the 10 gpm limit specifically addressed in the supplement steps. The 10 gpm limit is provided in the general instruction portion of the procedure, however, the supplement is normally the only portion of the procedure that is used when performing the daily leak rate determination. The licensee stated that the 10 gpm limit was in Supplement 1 until the procedure was revised per the procedure writer's guide. The licensee informed the inspector that Supplement 1 of Procedure 1103.13 would be revised to include the 10 gpm total RCS leakage limit. This item will remain open pending revision to Procedure 1103.13.

4.0 Followup of Event (Units 1 and 2 (93702)

4.1 Failure of Auxiliary Building Exhaust Fans 2VEF 8A and 8B

During normal plant operations on January 10, 1990, with reactor power at 90 percent, the operating auxiliary building exhaust fan, 2VEF 8A, tripped and the standby fan 2VEF 8B failed to auto-start. Investigation into the fan failures revealed that both motors had experienced electrical faults. While fans 2VEF 8A and 8B are not safety-related equipment, they do prevent airborne and gaseous radioactive material from reaching high concentrations in the auxiliary building by drawing air from the building and exhausting it through the plant vent. Licensee management prudently decided to maintain the plant in a stable condition of 90 percent power until repairs were effected and the operations staff took steps to reduce the buildup of airborne activity in the auxiliary building.

To reduce the buildup of airborne activity, the operations staff isolated floor and equipment drain system flow to reduce the amount of activity released into the auxiliary building atmosphere. By taking this action the operators caused the drain piping systems to become holdup volumes for the normal controlled leakoff. Although this was a good idea and probably did help to reduce the buildup of airborne activity, it was not an approved or revised method of operating the drain system. When the operators attempted to return the drain system to its normal configuration, the floor drains were unable to handle the high volume of leakage that had accumulated. The resulting backup of water caused a large percentage of the 317-foot elevation floor to become contaminated.

During the disassembly of Fan 2VEF 8B for repairs, the electrician effecting the disassembly noted arcing from the heater wiring despite the fact that hold cards had been placed on the heater breaker. Investigation revealed that the hold card for the heaters had been prepared using an uncontrolled reference. The uncontrolled document listed the wrong breaker as the heater power supply and because the electrical prints were not checked the error was not discovered.

The practices of using uncontrolled documents and operating systems in configurations not called for in the operating procedures are of concern to the inspector. Licensee management has removed uncontrolled reference material from the control room and is reviewing these incidents in detail.

The inspector will continue to review licensee actions in response to the incidents. Further review of this area will be conducted to determine if licensee administrative controls are adequate. This will be tracked as Unresolved Item 368/9002-01.

4.2 Followup on Unit 2 Reactor Trip

On December 31, 1989, Unit 2 tripped from 100 percent power due to a feedwater system transient. The licensee's initial troubleshooting and testing revealed that a loose termination in the "B" feedwater control system (FWCS) was the cause of the transient.

Prior to restarting the unit, licensee management decided to delay restart to allow time to perform maintenance on several pieces of equipment. The work scope included balance shots on 'B' and 'C' reactor coolant pumps, replacement of "C" excore nuclear instrument, complete inspection of components with Okonite tape splices inside containment, and repacking or repair of various leaking valves inside containment. The licensee's decision to delay restart to effect noncritical repairs is a positive indication that management's philosophy toward plant material condition is changing.

Unit 2 was restarted on January 6, 1990, and with the plant at 90 percent power on January 11, 1990, another feedwater transient occurred. Although the duration on the transient was much shorter than the December 31, 1989, event and no significant change in steam generator level occurred, the symptoms were identical. In response to the second event the FWCS was placed in manual, power was held at 90 percent, and an operator was assigned to monitor feedwater parameters continuously. The vendor that designed the FWCS for Unit 2 was contacted and the engineer responsible for the original design traveled to the site to review the transients. On the vendor's recommendation, the licensee placed monitoring equipment on the feedwater system that would provide information to aid the troubleshooting effort should additional transients occur. At the time of this report, no additional transients have occurred.

The licensee's troubleshooting efforts after the first transient were quite extensive and the loose terminal, when moved, gave indications similar to the transient. Calibration of the entire system was verified to be good. The inspector believes that the licensee's efforts to find the causes of the FWCS instability have been thorough.

4.3 Installation of Incorrect O-Rings in Unit 1 Turbine Governor Valve Electrohydraulic (EH) Control Solinoid

At 2:04 p.m. on January 6, 1990, with Unit 1 operating at 80 percent power, the control room received an EH system fluid tank low level alarm. The operations staff responded to the alarm and identified EH fluid spraying from the control solenoid (CV6631) for the No. 1 turbine governor valve. The control room staff recognized that reducing turbine load would close the No. 1 governor valve and allow the EH fluid to be isolated from CV6631. With power reduced to 69 percent, the operators were able to isolate the EH leak and restore EH fluid tank level.

Upon disassembly of CV6631, it was observed that the o-rings had been crushed and were seriously degraded. Since the control solenoid valves for all governor valves had to be overhauled during the midcycle outage, licensee management decided to inspect all the control solenoid valve o-rings.

Licensee management decided to attempt the inspection of one valve at a time with the turbine on line at 40 percent, however, the turbine control system was unable to maintain turbine load steady when the operators closed the No. 2 governor valve. The cause of the instability was inherent to the way the Unit 2 turbine controls had been adjusted to provide for more stable operation at 80 percent power. Because of the turbine instability when attempting to close governor valves other than No. 1, the licensee reduced power, removed the turbine from the grid, and completed the o-ring inspection and replacement on the remaining three governor valves.

The inspection revealed that the o-rings installed in all the governor valves were damaged in varying degrees. Review of the job order under which the o-rings were replaced showed no part identification for the o-rings to be used. Interviews with the technicians involved in the work revealed that the replacement o-rings were selected from an o-ring kit by a Westinghouse turbine representative. The o-rings were of the proper material, Viton, but were the wrong size. The oversized o-rings were crushed by the mating surfaces of the valve and this led to the premature failure.

The licensee had initiated a CR to establish the root causes of this event and at the end of the inspection period the CR the was still open. The inspector will review the licensee's determination of root causes and corrective actions when available.

4.4 All Four Unit 2 Steam Generator Level-Low Trip Channels Not Set in Accordance with the Governing Procedure

At 10:06 a.m. on January 31, 1990, with Unit 2 operating at 100 percent power, the licensee commenced shutting down the unit in accordance with TS 3.0.3 after declaring inoperable all four channels of the steam generator (SG) level-low trip circuitry because a preliminary recalculation of the trip stepoints revealed that the trip values were set at a level that was less than required by TS. Technical Specification Table 2.2-1 requires that each channel of the SG level-low trip circuitry be set at a value that is greater than or equal to 22.111 percent of SG level. ANO I&C Periodic Test Procedures 2304.37-.40, "Plant Protection System Channel A (through D) Test," require that the SG level-low trip setpoints be set between 23.15-23.35 percent. On January 31, 1990, a preliminary recalculation of the trip setpoints revealed that the original SG level-low trip setpoint calculation did not account for a nonconservative error of approximately 1.45 percent associated with the static head of pressure of the Rosemount (Model 1153, Series A) level detectors. On the basis of this information, the licensee determined that all four channels of the SG level-low trip circuitry were set in the range of 21.70-21.90 percent. Within 1 hour after discovery of the problem, the licensee declared an unusual event and began a controlled reactor shutdown. At 11:29 a.m. on January 31, 1990, the licensee terminated the unusual event after resetting all four channels of the steam generator level-low circuitry trip setpoints to 25 percent.

Later in the day on January 31, 1990, the licensee reperformed the steam generator level-low setpoint calculation and determined that the lowest possible trip setpoint was actually 22.33 percent. This is higher than the minimum TS requirement, but lower than the admininistrative limit specified in I&C Test Procedures 2304.37-.40. Discussions with licensee personnel revealed that the level transmitters were improperly calibrated because an improper span correction factor methodology for high line pressure was used. This error apparently occurred approximately 10 years ago when the wrong Rosemount transmitter technical manual was used as guidance in calibrating the newly installed Rosemount Model 1153A steam generator level transmitters. The licensee discovered this error as the result of its corrective actions associated with the discovery of calibration errors for some Unit 1 high pressure injection system Rosemount flow transmitters.

Although the failure to set the steam generator level-low trip setpoints in accordance with I&C Periodic Test Procedures 2304.37-.40 is a violation of TS 6.8.1.c, the safety significance is minimal. The licensee discovered this problem and took aggressive followup and corrective action. A Notice of Violation is not being issued because the criteria of Section V.G.1 of the NRC Enforcement Policy have been met.

4.5 Hose Inadvertently Entrained in the 2P-4B Service Water Pump

On January 29, 1990, while pumping down the "A" service water (SW) bay with a submersible pump and hose, the hose became entrained in the suction of the "B" SW pump (2P-4B). Following this event, the licensee stopped 2P-4B and declared it inoperable. The licensee drained the "B" SW bay and performed a visual inspection of 2P-4B. This included an inspection of the coupling, strainer, pump suction bell, and the lower impeller. The licensee found the hose coupling lodged between two impeller blades, and a 2-foot section of hose was found beneath the suction bell. The lower impeller had some small nicks where the coupling was lodged, but there was no evidence of other distress to the impeller. The pump was then run. Motor current and vibration readings as well as pump performance were found to be acceptable. On the basis of the above, the licensee returned 2P-4B to service.

Discussions with licensee personnel revealed that the pumping down of the service water bays with a submersible pump and hose is not governed by specific work instructions.

On January 29, 1990, the submersible pump hose became entrained in the suction of 2P-4B when an operator was attempting to remove a kink in the hose. A review of licensee records (CR-2-90-0056) documented a similar occurrence in August 1988 when a reinforced suction type hose was found in the suction bell of 2P-4B. This pump subsequently failed in October 1988, but the licensee had not conclusively determined if this had exacerbated the damage to the impeller snap rings of 2P-4B and its subsequent failure.

The licensee apparently had not implemented any corrective actions to preclude the entrainment of suction hoses into the SW pump suctions following the event in 1988. The inspector considered this to be an additional example of corrective action weaknesses that were previously identified and enforcement action taken by NRC Region IV in 1988. Following the January 29, 1990, incident, the licensee planned to perform a root cause analysis of the event and implement appropriate corrective action. The inspector will monitor licensee actions for this issue as an inspector followup item (IFI) 368/9002-02.

5.0 Operational Safety Verification (Units 1 and 2) (71707)

The inspectors routinely toured the facility during normal and backshift hours to assess general plant and equipment conditions, housekeeping, and adherence to fire protection, security, and radiological control measures. Ongoing work activities were monitored to verify that they were being conducted in accordance with approved administrative technical procedures and that proper communications with the control room staff had been established. The inspector observed valve, instrument, and electrical equipment lineups in the field to ensure that they were consistent with system operability requirements and operating procedures.

During tours of the control room, the inspectors verified proper staffing, access control, and operator attentiveness. Adherence to procedures and limiting conditions for operations were evaluated. The inspectors examined equipment lineup and operability, instrument traces, and status of control room annunciators. Various control room logs and other available licensee documentation were reviewed.

During the early portion of the inspection period, the inspector closely observed the increasing seal leakage from the "A" and "D" reactor coolant pumps (RCP). The cause of the leakage was the degrading of the upper mechanical seals on both pumps. While staging across the lower seals increased as designed, it was not sufficient to prevent an increase in the seal leakage. Total leakage from both seals increased to approximately 1-1/2 gpm, while the other two pumps have essentially zero seal leakage. The current leak rate of 1-1/2 gpm appears to have stabilized, with no additional signs of further seal degradation. The inspector has noted that the licensee is closely monitoring RCP seal leakage.

The inspector observed that the Unit 1 upper north electrical penetration room, which contains the Unit 1 reactor building personnel hatch, was being used as a storage area for various outage-related items. The area was extremely cluttered with piles of cables, solvent cans, and hoses reaching almost to the lowest cable trays in the room. The inspector relayed his concern over the use of this area for miscellaneous storage to licensee management. The licensee has begun the process of cleaning this area and at the close of this inspection period only a few items remained.

No violations or deviations were identified.

5.1 Flow Testing Unit 2 Service Water (SW) Pumps (71707)

All three SW pumps were tested to establish baseline pump performance values for ASME Code Section XI compliance verification. These values were used for comparison with the original manufacturer's pump curve to verify satisfactory pump performance. The values will also be used in comparison with future pump test results. Procedure 2305.019, "Service Water Pumps Flow Test," was used to gain pump discharge pressure data for various flow rates. A pump performance curve (flow versus discharge pressure) was obtained from the test data for each SW pump. These curves were compared to the original manufacturer's curves and the pump's performance was verified to be acceptable. During the last refueling outage, the final flow element was installed which allowed the data collection needed to derive the pump curves.

In the limits and precautions section of Procedure 2305.019, a limit is given on SW flow of 14,000 gpm which should not be exceeded for any SW pump. Table 9.2-3, "Service Water Pump Data," in the Unit 2 Safety Analysis Report (SAR) provides a pump runout flow rate of 14,000 gpm. When fully loading SW Pump 2P-4B, the total flow was measured at 14,300 gpm. The data was collected and SW flow through the emergency diesel generators' heat exchangers was secured. Flow then dropped to 14,150 gpm. Again data was collected and additional SW loads were reduced such that total SW flow was 13,625 gpm. The engineer that was working with the operator during the test stated that exceeding the 14,000 gpm limit was not a concern because the information in the SAR was not correct. The inspector questioned why the 14,000 gpm flow limit was given in the procedure if the actual limit is higher. The engineer stated that the SAR would have to be changed prior to changing the limiting value given in the procedure.

The inspector does not consider placing overly conservative limits in test procedures a good practice, especially if these limits are likely to be exceeded during the test. The licensee stated that the upper flow limit for SW pumps would receive additional review. This issue will be tracked by inspector followup item (368/9002-03) pending the inspector's review of the licensee's action to resolve the 14,000 gpm flow limit imposed on the SW pumps.

6.0 Monthly Surveillance Observation (Units 1 and 2) (61726)

The inspector observed the TS-required surveillance testing on the various components listed below, verified testing was performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, test results conformed with TS and procedure requirements, test results were reviewed by personnel other than the individual directing the test, and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector witnessed portions of the following test activities:

- Monthly Test of a Digital Subsystem for the Unit 1 Engineered Safeguards Actuation System (Procedure 1304.046, Job Order 803309). During the test, an instrumentation and control technician noted a minor sequencing error in the procedure. The test was stopped and the system was returned to its normal configuration to allow the completion of a temporary change to correct the procedural error.

- Annual Test of Emergency Feedwater Pump 2P-7B (Procedure 2106.06, Job Order 804840)

- Monthly surveillance test of Train "A" of the control room emergency air conditioning system (Procedure 2104.07, Supplement 1, Job Order 805218)

- Monthly Surveillance Test of Low Pressure Safety Injection (LPSI) Pump 2P-60B (Procedure 2104.40, Supplement 2). While performing the monthly run of the pump, Supplement 7, "Integrity Test and Leak Rate Determination for "B" Train," of Procedure 2104.40 was also completed. The inspector accompanied the nonlicensed operator who performed the walkdown inspection of LPSI system Train "B". The operator had a thorough understanding of the various operational modes of the system, i.e., shutdown cooling and low pressure injection, and of the details involved with the system integrity test.

6.1 Compliance With Independent Verification Requirements

Monthly surveillance test of Emergency Diesel Generator (EDG) 2K4A (Procedure 2104.30, Supplement 1). The inspector observed a portion of the hourly run and the air roll of the EDG after it had been shut down for 15 minutes. The purpose of the air roll is to rapidly cycle the diesel approximately two revolutions with the air start system to allow draining of excessive lube oil from the piston and cylinder areas. Prior to cycling the EDG, Valve 2ED-1049A is closed to isolate the air start header from the lube oil booster. This prevents the lube oil in the booster reservoir from being injected into the lubrication system when the EDG is air rolled. Valve 2ED-1049A is then opened after the air roll to allow injecting the lube oil booster contents into the lube oil system during the next EDG start. Procedure 2104.36 then requires an independent verification that 2ED-1049A is open.

The inspector observed an operator step up on the EDG platform and open 2ED-1049A. The operator then called out that 2ED-1049A was open and a second operator standing on the floor initialed the independent verification signoff that 2ED-1049A was open. The inspector was standing on the floor and noted that the second operator was not closely observing the other operator when the valve was opened. Later the inspector stepped up on the platform and verified that 2ED-1049A was open. Also the inspector noted that verification of valve position required stepping up on the EDG platform to observe the position of the valve.

The inspector reviewed Operations Procedure 1015.01, "Conduct of Operation," which defines indepencent verification as the act of confirming by independent means or by a second individual at a time other than the initial verification. The licensee's management agreed with the inspector that the process used to open 2ED-1049A did not constitute an independent verification. A read and sign training assignment was required of all Unit 2 operations personnel to reinforce the requirement of independent verification. The operations manager also stated that he would discuss this issue with operations personnel during his weekly lecture to crews that are in training. The licensee stated that the current definition and instructions regarding independent verification would be reviewed to ensure that management expectations of independent verification were being carried out. The inspector will continue to monitor the performance of independent verification for both Units 1 and 2.

No violations or deviations were identified.

7.0 Monthly Maintenance Observation (Units 1 and 2) (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and in conformance with the TS.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, quality control records were maintained, activities were accomplished by qualified personnel, parts and materials used were properly certified, radiological controls were implemented, and fire prevention controls were implemented.

Work requests were reviewed to determine the status of outstanding jobs and to ensure that priority is assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed:

- Repair of seat leakage on service water pump discharge isolation Valve 2SW-3A (Job Order 804464). After partial disassembly, it was discovered that the butterfly disc valve was not making full contact with the valve seat. An adjustment of the travel limits was made to allow proper "seating" of the valve when in the closed position.

  During the valve repair, the licensee noted that one of the dowell pins which maintain horizontal alignment of the disc was missing. This allowed the rotating shaft of the manual operator to move out from the operator approximately 2 1/2 inches. While the licensee believes the movement of the shaft did not cause the back leakage, the inspector noted that additional movement of the rotating shaft may have resulted in it becoming disconnected from the operator.

  A new dowel pin was installed, then both pins were tack welded to the disc to prevent any movement. The same modification (tack welding) was completed for the dowel pins in the "B" and "C" discharge isolation valves. The licensee had identified missing and loose dowel pins in two valves of the same design that are located in the SW cross-connect and auxiliary cooling water lines during the last refueling outage. Larger dowel pins were installed in these valves and four additional valves with the same design and maintenance history during the outage. The licensee's decision not to modify the dowel pins in the three SW discharge isolation valves during the outage was based on the valves not serving a safety function. Based on the possibility that the valve operator may have become disconnected from the disc, the decision to delay the dowel pin modification does not appear to have been conservative. The licensee performed an additional review of similar butterfly valves and determined that no other valves are susceptible to dowel pin failure.

- Repair of leak on Positive Displacement Charging Pump 2P-36A (Job Order 788700). Operations personnel had reported a leak in the area of the middle end cap for the center piston. After pump disassembly a liquid penetrant inspection was performed on the pump casing and end cap. A linear indication was identified on the end cap. Following cleaning, the cap was again inspected to locate the indication for weld repair, however, the indication could not be located during the second inspection. The original gasket was also inspected and no sign of a possible leak path was identified. A third penetrant inspection of the end cap and a second inspection of the pump casing were performed and again no indications were identified. The pump was reassembled with new end cap gaskets. During subsequent testing no leaks were identified.

While the pump was disassembled, new suction check valves were installed. The new valves were modified by cutting 0.100 inch off the bottom of the valves. This allowed the valves to be installed deeper into the tapered bores of the pump casing and would increase the interference fit between the valves and casing. The need to perform this modification resulted from an event with the "C" charging pump when two of the three check valves became loose from the casing and came into contact with the pump plungers. The suction valves for the "C" charging pump were modified in August 1989. Therefore, after completion of this work on "A" charging pump, all three of the charging pumps will have received this modification.

° Retaping electrical spliced connections. The inspector followed up on the licensee's actions to replace the Scotch 33 tape overlay with Okonite 35 tape. This resulted from earlier discussions with the NRC concerning the environmental qualification of tape splices that are wrapped with Okonite T-95 tape and Scotch 33 overlay. Originally, the licensee retaped 27 motor operated valve (MOV) operator splices. The licensee later performed a more indepth review for components with the Okonite T-95 and Scotch 33 taped splices. For Unit 1, 39 additional components were identified and 22 components for Unit 2.

The inspector observed retaping of the following components:

- Borated water storage tank outlet Valve CV-1407

- Unit 2 High Pressure Injection Pump 2P-89B

- Service water supply Valve CV-3813 to the Unit 1 reactor building cooling units

- Unit 1 decay heat vault room Cooler VUC-1B

The licensee plans to have completed retaping all of the additional electrical splices by mid-February with the exception of components located in the Unit 1 reactor building. These components have been added to the Unit 1 forced outage work list.

No violations or deviations were identified.

8.0 <u>In-Office Review of Licensee Reports (90712)</u>

The following LERs and licensee special reports (LSRs) were reviewed and closed. The inspector verified that reporting requirements had been met, causes have been identified, corrective actions appeared appropriate, reactive NRC inspection is not warranted, generic applicability had been considered, and that the LER forms were complete. The inspector confirmed that violations of TS, license conditions, or other regulatory requirements had been adequately described. Appropriate enforcement action has previously been taken for all the below listed LERs. This resulted in escalated enforcement action and/or Severity Level IV violations for some of the below listed LERs.

a. (Closed) LER 313/88-013 (Supplement 1): "Potential Failure of a High Pressure Injection Pump to Start on Engineered Safeguards Signal Due to a Breaker Wiring Error."

b. (Closed) LER 313/88-019: "Inadvertent Emergency Feedwater System Actuation Due to Personnel Error While Draining a Steam Generator for Secondary Side Chemistry Cleanup."

c. (Closed) LER 313/88-020: "Nonsafety-Related Ventilation System Affected the Containment Building Penetration Room Ventilation System Capability to Maintain a Slight Negative Pressure, to Ensure Filtration of Leakage, as a Result of an Original Plant Design/Construction Deficiency."

d. (Closed) LER 313/88-021: "Steam-Driven Emergency Feedwater Pump Inoperable During Plant Heatup Due to Personnel Error."

e. (Closed) LER 313/88-023: "Inadequate Work Controls Resulted in a Non-Isolable Reactor Coolant System Leak Which Necessitated a Plant Shutdown."

f. (Closed) LER 313/89-002: "Reactor Trip Caused by Turbine Generator Exciter Failure and Failure of Various Components in Main Feedwater System Results in Steam Generator Overfill."

g. (Closed) LER 313/89-005: "Personnel Error Results in an Inadequate Procedure Which Causes Calculated Reactor Shutdown Margins Less Conservative Than Assumed in the Plant's Design Basis."

h. (Closed) LER 313/89-007: "Inadequate Design Change Process Results in Failure to Identify a High Pressure Injection System Line Break Scenario Which Could Cause the System to be Incapable of Supplying Adequate Core Cooling."

i. (Closed) LSR 313/89-016: "Emergency Diesel Generator Fire Suppression System Rendered Inoperable Due to Maintenance Activities."

j. (Closed) LER 368/85-028: "Personnel Error Results in the Potential Inoperability of the Safety Injection Tanks Due to Cross-Connection of the Tanks Through the Nitrogen Addition System Piping."

k. (Closed) LER 368/87-010: "Plant Protection System Panels Seismic Qualifications Compromised Due to Loose Fasteners Caused by Personnel Error."

l. (Closed) LER 368/88-016 (Supplement 1): "Inadequate Procedures Result in Exceeding the Technical Specification Limit for Containment Spray System Train B Actuation Response Time and Failure to Perform One Response Time Test for the Emergency Feedwater System."

m. (Closed) LER 368/89-004: "Inadequate Procedure Results in the Inability to Automatically Transfer High Pressure Safety Injection Sump from the Refueling Water Tank to the Containment Sump with the Plant in Mode 4 (Hot Shutdown) During Startup."

9.0 Exit Interview

The inspectors met with Mr. N. S. Carns, Director, Nuclear Operations, and other members of the AP&L staff at the end of the inspection. At this meeting, the inspectors summarized the scope of the inspection and the findings. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.