APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 498/92-32
499/92-32

Operating License: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas 77251

Facility Name: South Texas Project Electric Generating Station, Units 1 and 2

Inspection At: Matagorda County, Texas

Inspection Conducted: October 25 through December 5, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector
R. J. Evans, Resident Inspector
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Approved: A. T. Howell 1-19-93
A. T. Howell, Chief, Project Section D Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, operational safety verification, engineered safety feature system walkdown (Unit 1), maintenance and surveillance observations, complex surveillance (Unit 1), refueling activities (Unit 1), followup on previously identified violations, and licensee event report followup.

Results:

- The falsification of records (log sheets) by two chemical operators resulted in their dismissal. An unresolved item will be used to track further NRC review of this incident (Section 2.1).

- Personnel errors occurred which resulted in work being performed on the wrong component, train, and unit. An unresolved item will be used to track further NRC review of these incidents (Section 2.2). A similar example was documented during a previous, recent, NRC inspection.

- The draining of oil from a reactor coolant pump motor, because of a false level indication, resulted in bearing damage. One of the causes of the event was a lack of knowledge of a standing order (Section 2.3).

- Four Unit 1 residual heat removal pump trips, occurring in an 11-day period, were caused, in part, by procedure weaknesses and operator inattention. A station problem report (SPR) was not initiated until the fourth occurrence. Similar instances of failure to initiate an SPR for conditions adverse to quality were identified by NRC during the conduct of an Operational Safety Team Inspection, which was ongoing at the end of this inspection period. These instances of failure to initiate an SPR will constitute an additional example of a violation for failure to follow the SPR procedure which will be documented in the OSTI inspection report (Section 2.4).

- An acid spill occurred because of weaknesses in the equipment clearance order procedure. No personnel were injured (Section 2.5).

- The discovery of an inadequate surveillance procedure resulted in a Technical Specification (TS) 3.0.3 entry. The criteria for enforcement discretion were satisfied. However, this was the third example in recent months in which a deficient surveillance procedure resulted in one or both un being placed in TS 3.0.3 (Section 2.6).

- Failure to monitor plant drainage points resulted in an air handling unit failure and halon actuation because a plugged drain did not allow condensation to be diverted away from the air handling unit, causing an electrical short (Section 2.7).

- The implementation of the reactor trip prevention program may have precluded Unit 2 from tripping when the startup feedwater pump tripped off line with a steam generator feedwater pump out of service for maintenance. However, the startup feedwater pump tripped because of a long-standing problem with rainwater intrusion into plant equipment (Section 2.8).

- A walkdown of the Unit 1 Class 1E 125 volt direct current power system was performed. All components were correctly aligned and a good level of housekeeping was noted in the Electrical Auxiliary Building (Section 3).

- The balance of plant (BOP) diesel generators (DGs) recently experienced a high number of start failures, which had an adverse impact on the reliability of the DGs (Section 4.1).

- The liner of Cylinder 6R of Emergency Diesel Generator 13 was replaced because of indications of tin transfer. The unintentional automatic start of an emergency diesel generator was caused by human error and a deficient procedure. Weaknesses in the development and maintenance of design drawings were identified when the inspectors noted an inaccurate logic drawing (Section 4.2).

- Three surveillance tests were witnessed and good self-verification and supervisory oversight were observed (Section 5). Two complex surveillances were effectively performed (Section 6).

- The Unit 1 fourth refueling outage was several weeks behind schedule because of refueling equipment problems and unanticipated emergency diesel generator rework. A technician fell into the reactor cavity but was not injured or contaminated. The reactor containment building was noted to be clean following the refueling outage. All major work activities were completed (Section 7).

Summary of Inspection Findings:

- Unresolved Item 498;499/9232-01 was opened (Section 2.1).

- Unresolved Item 498;499/9232-02 was opened (Section 2.2).

- Enforcement Action 498;499/91-55 was closed (Section 8.1).

- Violation 499/8868-07 was closed (Section 8.2).

- Violation 498;499/9121-03 was closed (Section 8.3).

- Violation 499/9224-02 was closed (Section 8.4).

- Licensee Event Report 498/91-014 was closed (Section 9.1).

- Licensee Event Report 498/92-006 was closed (Section 9.2).

- Licensee Event Report 499/92-003 was reviewed but left open (Section 9.3).

- Licensee Event Report 499/92-006 was closed (Section 9.4).

Attachments and/or Enclosures:

- Attachment 1 - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

On September 18, 1992, an orderly plant shutdown was performed as scheduled for the unit's fourth refueling outage. The planned outage duration was 62 days. The unit entered "no mode" on October 5, 1992, when all fuel was removed from the reactor cavity and the in-containment storage area. At the beginning of this inspection period, Unit 1 was in a "no-mode" condition. The unit entered Mode 6 (Refueling) again on November 12, 1992. Core reload was completed 4 days later. Unit 1 entered Mode 5 (Cold Shutdown) on November 22, 1992, and remained in Mode 5 through the end of the inspection period.

At the beginning of this inspection period, Unit 2 was operating in Mode 1 (Power Operation) at 100 percent power. The unit remained at full power until November 20, 1992, when unit power was reduced to 80 percent to allow for maintenance on Steam Generator Feedwater Pump 23. The next day, unit power was reduced to 59 percent when the startup feedwater pump tripped off line. Unit 2 power was increased to 80 percent on November 23, 1992, when the startup feedwater pump was returned to service. Power was increased to 100 percent the next day when the steam generator feedwater pump was returned to service. The unit remained at full power through the end of inspection period.

Several organizational changes were recently announced by the licensee. The Operations Training Manager assumed the duties of Nuclear Training Department Manager (acting) on October 13, 1992, when the previous manager resigned. The Planning and Assessment Manager (acting), who was also the Administrator of Participant Services (an owner interface organization), assumed the duties of Nuclear Training Department Manager on October 16, 1992. A senior consultant in the Planning and Assessment Department assumed the duties of Planning and Assessment Manager (acting) on October 16, 1992. The senior consultant's assignment became permanent on November 1, 1992. The Operations Training Manager returned to his normal position on October 16, 1992.

2 OPERATIONAL SAFETY VERIFICATION (71707)

The purpose of this inspection was to ensure that the facility was being operated safely and in conformance with license and regulatory requirements. The following paragraphs provide details of specific inspector observations during this inspection period.

2.1 Falsification of Records

In response to NRC Information Notice 92-30, "Falsification of Plant Records," the licensee's Quality Assurance Department conducted an expanded review of plant records. As a result, the licensee identified, on October 9, 1992, that two chemical operators had signed log sheets indicating the completion of rounds when, in comparison to security access records, they did not access the area where the activity in question would have had to occur. The licensee issued SPR 92-0791.

As part of their daily rounds, chemical operators are required to observe oil levels in three sumps outside each units' radwaste truck bays. Signoffs for these verifications are included on the applicable log sheets, as required by Procedure OPCP01-ZA-0020, Revision 3, "Chemical Operations Logs and Reports." In June 1992, an SPR was issued because a radwaste truck bay sump overflowed. As a compensatory measure, a requirement for chemical operators to observe the level of the sump was added to the log sheet. The shiftly check was also required by night orders, which were issued immediately after the overflow event. This order is documented in Chemical Operation Section Operating Order 92-006.

Quality Assurance selected as a sample, logs and access records for time periods in February and July 1992. These periods are before and after receipt of Information Notice 92-30. Review and comparison of these records revealed that there were several instances in which personnel had signed off the log sheet indicating their completion, but there was no evidence to indicate that access to the truck bays had actually occurred. The doors that were checked are Door 1M2533 for Unit 1 and Door 2M2533 for Unit 2. The dates for these occurrences were: February 2, 6-10, 11, 12, 13-15, 16, 17, 18, 19, and July 1, 2, 4, 5, 6, 9, 10, 11, 13-15, 18, and 20, 1992. As a result of the licensee's review, two chemical operators were dismissed for falsifying the log sheets. This matter is considered an unresolved item (498;499/9232-01) pending further review by NRC.

2.2 Errors in Work Performance (Units 1 and 2)

An adverse trend developed during this inspection period involving errors resulting from work being performed on the wrong component, wrong train, and wrong unit. The first occurrence of this type of error occurred during the previous resident inspection period and is documented in NRC Inspection Report 50-498/92-29; 50-499/92-29. That incident involved work performance on incorrect equipment on October 19, 1992, when an underfrequency trip actuating device operational test was performed on Reactor Coolant Pump 2A when work start had been given for Reactor Coolant Pump 2C. During this period, the following events were identified:

- On October 29, 1992, while performing Procedure OPSP11-RC-0003/0004/0005, "Local Leakage Rate Test Reactor Coolant Pump Seal Supply Train A, -B, and -C," contractor personnel incorrectly performed the procedure. The containment isolation valves intended to be tested were CV0034A, -B, and -C. Test personnel erroneously connected the test equipment to Test Connections CV0600A, -B, and -C instead of CV0594A, -B, and -C. As a result of this error, Containment Isolation Valves CV0033A,B,&C were incorrectly tested. It was subsequently determined that the contract technicians performing the work at the test valves did not have a copy of the procedure with them. The licensee issued SPR 921016.

- On November 2, 1992, while performing Procedure OPSP02-SI-0964, "Accumulator C Pressure Group 3 ACOT (P-0964)," an instrumentation and controls technician loosened leads TB-J Term 10 (N2SI28C1XZ P-J10(Red)) and TB-J Term 11 (N2SI28C1XZ N-J11 (White)) with a flat blade screwdriver. The technician then reached down to his tools and changed to a holding screwdriver. He then returned to the terminal block and erroneously proceeded to lift the wires at TB-J Term 7 and TB-J Term 8. This action resulted in a control room Low/High Accumulator Level alarm. Control room personnel responded to the alarm and the leads removed from TB-J Term 7 and TB-J Term 8 were relanded. The analog channel operability test was then completed with no other problems. The licensee issued SPR 921059.

- On November 5, 1992, during package closure of Unit 1 qualified display parameter system work packages, the licensee discovered that two packages were performed on Unit 1 equipment when they were written for Unit 2. The packages in question involved Service Requests AM-164610 for Data Processing Unit A and AM-164611 for Data Processing Unit C. No negative impact occurred from this error since the work was a repetition of work that had already been performed in Unit 1. Service requests had to be reinitiated for Unit 2. The error was preliminarily attributed to commingling of service requests in the work control center and the subsequent failure to identify the error in the granting of work start authority. The licensee issued SPR 921106.

- On November 7, 1992, Service Request 173475 was written to repair a steam leak on Heater Drip System Valve N2HDLC7222. The leak was actually on Valve N2HDLC7223. The reactor plant operator incorrectly identified the valve because he was unable to get close enough to the valve tag as a result of the steam leak. Instrumentation and controls technicians were in the process of connecting instruments in support of mechanical maintenance when they identified that Valve N2HDLC7223 had been tagged out by Equipment Clearance Order 92-2-1805 in preparation for leak repair of the incorrectly identified leaking valve (Valve N2HDLC7222). They also discovered the pipe plug removed from the top of the level pot. This did not agree with the service request valve number (N2HDLC7222), and work was stopped. Subsequent investigation disclosed that the mechanical maintenance personnel had performed work on Valve N2HDLC7223. This condition represents an error in the generation of a service request which was not identified or corrected. The issuance of an equipment clearance order on the wrong valve, which was the valve that was actually leaking, resulted from this error. The licensee issued SPR 921124.

The following events were subsequently identified through a review of recently issued SPRs:

- On September 28, 1992, Equipment Clearance Order 1-92-8030 was issued for Condenser Waterbox 12N in preparation for chemical cleaning. The Waterbox inlet, on the east side, was unbolted and work was continued to remove the bellows. The bolting crew moved to the outlet, on the west side, and started removing bolts from Waterbox 12S instead of 12N. Waterbox 12S was in service at the time. Seven of the 64 bolts had been removed when the contractor noticed water leaking. The bolts that had been removed were immediately replaced. The licensee issued SPR 920636.

- On October 12, 1992, during implementation of Work Package 116446-EP01 for the rework of Pipe Support EW-1107-HL5006, an American Society of Mechanical Engineers (ASME) Class 3 NF support, craft personnel incorrectly implemented the package on Support EW-1128-HL5003, also an ASME Class 3 NF support. The pipe supports for EDG 12 had already been reworked when the craft began to work on EDG 11 supports. The craft assumed that Support EW-1128-HL5003 was to be worked because they had worked the corresponding support for EDG 12. However, this support was not required to be worked. The craft failed to properly review the work package and did not verify that they were working on the wrong component. Compounding this error was the fact that quality control personnel inspected and accepted the work on the incorrect support. The licensee issued SPR 920838.

In response to the adverse trend, the licensee issued SPR 921139 to identify the cause of the trend and take immediate compensatory actions. These actions included a briefing by the Maintenance Manager to all employees on management expectations concerning attention to detail and self-verification, issuing Plant Bulletin 216, "Attention to Detail," and conducting meetings with appropriate managers to determine commonalities. The further review of each specific incident will be tracked by an unresolved item (498;499/9232-02) in order to determine whether any of these problems resulted in noncompliance with NRC requirements.

2.3 <u>Reactor Coolant Pump Lower Motor Bearing Damage (Unit 1)</u>

On October 31, 1992, an uncoupled motor run of RCP 1A was performed. Prior to the motor run, approximately 3 gallons of oil were removed from the lower bearing oil reservoir, which has a capacity of approximately 20 gallons, to clear a high level condition. The RCP 1A motor was started and, 2 minutes later, the lower bearing temperature was noted to be indicating higher than normal. Oil samples were taken to determine whether bearing damage had occurred. The samples taken confirmed that the bearing had been damaged and the bearing was subsequently replaced.

The cause of the bearing damage was determined to be inadequate lubrication of the bearing. The removal of the 3 gallons of oil caused the inadequate lubrication. The oil was removed to clear a high level condition, which was later determined to be a false level indication. Blockage in the sensing line to the sight glass was discovered. The sensing line was subsequently blown out with air and a brown colored, gelatinous material was recovered. The material was sent offsite for analysis. The results indicated the presence of an oil additive and dispersant, that a stearate soap type material was being formed by the oil additives, and that oxidized oil material was present.

A review of the work history on RCP 1A indicated that the oil was probably the original oil that was installed in 1986. According to the most recent sample results, which were taken at the start of the outage, the oil was still considered satisfactory. The licensee's sampling program implemented the guidance provided in the technical manual. Routine changeout of the oil was not required as long as the samples were satisfactory. Additionally, routine oil changeout was not desired, in part, because of the problems associated with the disposal of the waste oil. The motor vendor, Westinghouse, noted that they have observed sludge like material in some of the RCP motors that they have refurbished, but not to the extent that could result in a sensing line obstruction.

The Westinghouse Owners Group Oil Evaluation Program, a program in which the licensee is participating, is scheduled to be completed in 1995. The licensee believes that an enhanced reactor coolant pump motor oil sampling program or replacement schedule will be developed as a result of the program.

One contributing factor to the event involved noncompliance with standing orders. Standing orders were in place that provided instructions to contact the responsible maintenance planner when oil levels are found out of tolerance on large motors. The planner then would contact the responsible system engineer for root cause analysis and recommendations. The failure of the individuals involved to be aware of and adhere to the standing order was indicative of weakness in complying with the standing order program.

Corrective actions taken included replacing the RCP 1A damaged bearing and replacing the oil in all four RCPs. No sludge-like material was found in the other three RCPs' oil level sensing lines. Corrective actions planned included procedure enhancements, review of work history to determine whether the source of the sludge can be identified, replacing the Unit 2 RCPs' oil during the next refueling outage, and providing additional training for adding and draining oil from large motors. Until additional vendor guidance is provided, the licensee plans to change out the oil in each RCP motor every other refueling outage regardless of the sample results.

2.4 Residual Heat Removal Pump Trips on Low Flow (Unit 1)

Between November 9 and 19, 1992, Unit 1 experienced four residual heat removal (RHR) pump trips on low flow. Each specific event was of low safety significance because shutdown cooling was being maintained by other trains, or shutdown cooling was not required because the unit was in "no-mode" operation. An SPR was not initiated until after the fourth event. At least two of the trips were the result of incomplete procedure guidance and operator inattention.

During RHR system operation, each of the three pumps discharges approximately 3000 gallons per minute (gpm). The pumps are protected from overheating and a loss of suction flow by miniflow bypass lines that assure flow to the pump suction. A remotely controlled motor-operated valve is located in each mini flow line. Flow instrumentation is provided in the discharge of each pump to indicate pump flow in the control room. When the RHR flow decreases to the low setpoint of 925 gpm, the pump is automatically tripped to prevent pump damage.

On November 9, 1992, RHR Pump 1C tripped on low flow while operations personnel were attempting to drain down the reactor cavity. Steps 10.19 and 10.20 of Procedure 1POP02-RH-0001, Revision 12, "Residual Heat Removal System Operation," provided instructions to close the miniflow isolation valve and then open the refueling water storage tank return isolation valve until the applicable train flow indicated between 925 and 3000 gpm. During the performance of the steps, the miniflow isolation valve was closed, but the manual return isolation valve was not opened in a timely manner by the operators. This caused pump flow to drop to below the pump trip setpoint and RHR Pump 1C tripped offline. The pump was restarted about 3 minutes later. Short-term corrective actions taken included revising System Operating Procedure 1POP02-RH-0001 to ensure that a higher flow rate exists prior to performing Steps 10.19 and 10.20. This change was made to ensure that the flow rate will not drop to below the pump trip setpoint when the valves are repositioned.

On November 10, 1992, RHR Pump 1A was started in order to perform a postmaintenance test of Pressure Differential Instrument PDI-871. The local pressure gauge was installed in accordance with Plant Modification 89220 to assist plant personnel during in-service testing of the pump. As part of the modification, the high pressure side of the pressure instrument was connected to the flow transmitter that was located downstream of the pump discharge. Apparently, an erroneous low flow signal was generated while the pressure gauge was being valved into service. The pressure instrument was vented and the pump was restarted 4 minutes later.

On November 17, 1992, RHR Pump 1C was started in order to perform a dynamic vent on the Train C RHR system. Pump 1C tripped on low flow because an air bubble apparently was in the piping, which simulated an erroneous low flow signal when the air passed through the flow transmitter element. A second static vent of the pump casing was performed to ensure that all air was vented from the piping. RHR Pump 1C was restarted approximately 20 minutes later to complete the dynamic venting.

On November 19, 1992, RHR Pump 1B tripped on low flow while transferring low pressure letdown from RHR Train A to B. The licensed operator manually repositioned valves and left the panel where the RHR flow indication was located to monitor the letdown lineup and reactor coolant level at another panel. While at the other panel, RHR Pump 1B tripped on low flow. Low pressure letdown was immediately reestablished on Train A. RHR Pump 1B was restarted 13 minutes later. The event was caused by: a lack of self-verification because the operator did not follow up on his valve manipulations in a timely manner; and a lack of procedural guidance because the letdown isolation process was not clearly described in the plant procedures.

An SPR was written following the November 19, 1992, event. The previous events were not documented in SPRs because the operators did not consider them to be conditions adverse to quality. During the conduct of an Operational Safety Team Inspection (OSTI), which was ongoing at the close of this inspection (refer to NRC Inspection Report 50-498/92-35; 50-499/92-35), NRC identified other instances of the failure of licensee personnel to initiate an SPR for conditions adverse to quality. As a result, these instances of failing to initiate an SPR will constitute an additional example of failing to comply with the SPR procedure as identified in NRC Inspection Report 50-498/92-35; 50-499;92-35. The four events were still under review by the licensee at the end of the inspection period. Corrective actions being considered, or which have been completed, included procedure enhancements, issuance of night orders, and review of the system and pressure instrument venting process.

2.5 Acid Spill (Unit 2)

On November 10, 1992, the Unit 2 condensate polishing system cation acid pump discharge pulsation damper drain isolation valve, 2CP-1274, was found in the open position, allowing concentrated sulfuric acid to drain onto the floor. The acid was collected in a drain near the pump and then flowed to the condensate polishing sump inside the turbine generator building. Strong fumes were coming from the sump and were noticed at the condensate polishing system control panel; however, no personnel were injured. The drain valve was closed and the pH of the sump was determined to be acidic. The area was secured and sodium hydroxide was slowly added to the sump to neutralize the acidic water prior to discharging the water to the low total dissolved solids tanks. A fan with ducting was used to route the fumes outside the building. Approximately 500 gallons of 27 percent sulfuric acid were spilled.

A subsequent licensee review disclosed that maintenance, under Service Request 173289, had been completed 2 hours and 50 minutes before the leak was identified on Cation Acid Pump B. The equipment clearance order was issued by Plant Operations. The maintenance craft then obtained work start authorization. Prior to the start of work, the head chemical operator decided to close the acid tank outlet valve and open the pulsation damper drain valve in order to increase personnel safety. Neither valve was listed on the equipment clearance order. The head chemical operator did not document the manipulation of the valves within the equipment clearance order boundary. He also did not communicate to anyone that he had manipulated the valves. The applicable equipment clearance order procedure, OPGP03-ZO-0039, "Operations Configuration Management," does not require that the manipulations be documented because the valves were within the equipment clearance order boundary and because this particular system does not require independent verification. The failure to procedurally require documentation of the valve manipulations is considered a weakness. The head chemical operator received counseling on the importance of providing adequate turnover information.

2.6 Incomplete Testing of Feedwater Isolation Logic Slave Relays (Units 1 and 2)

In response to the May 19, 1992, TS 3.0.3 entry event, the licensee committed in Licensee Event Report (LER) 498/92-004 to perform a review of selected surveillance procedures to ensure that they satisfy TS requirements. During this review, an additional procedural deficiency was identified on November 11, 1992. The procedure for time response testing of feedwater isolation from the safety injection logic incorrectly required the testing of the wrong slave relays. On November 11, 1992, at 3:06 p.m., Unit 2 entered TS 3.0.3 when the Unit 2 feedwater isolation actuation relays were declared inoperable because TS 3.3.2 requirements were not satisfied. TS 4.0.3 was also entered, which required the time response testing of the relays be completed within 24 hours. Service Request SR 175465 was issued to perform the time response tests in Unit 2 and the testing was completed at 7:06 a.m. on November 12, 1992. TS 3.0.3 and 4.0.3 were also exited at this time. The NRC operations center was notified of the TS violation on November 12, 1992, at 11:37 a.m. The applicable surveillance procedures were revised and the Unit 1 relays were tested, using the updated procedures, on December 5, 1992, prior to the unit's entry into Mode 4.

The cause of this event was inadequate development and review of the original surveillance procedures that time response tested the slave relays. The failure to comply with TS Surveillance Requirement 4.3.2.2 constituted a violation of NRC requirements. However, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B.2 of Appendix C to 10 CFR 2. The violation was: (1) licensee identified; (2) reported to the NRC operations center; (3) identified as the result of corrective actions for a similar problem; (4) corrected in a timely fashion; and (5) not a willful violation. Corrective actions taken included completion of the required testing, revising the applicable surveillance procedures, and continuing the surveillance procedure review process. One corrective action being considered by the licensee included expansion of the number of surveillance procedures scheduled for technical review because the number of deficient procedures being identified is indicative of continuing problems with procedural adequacy.

The inspectors noted, however, that this was the third recent event in which one or both units had to be placed in TS 3.0.3 because of inadequate engineered safety features (ESF) surveillance tests. Because of the number of deficient ESF surveillance tests that have been identified by the licensee in recent months, the inspectors questioned the adequacy of other types of surveillance procedures. The inspectors determined that when the corrective actions are for LER 498/92-004 are completed, the licensee will make a determination as to whether the scope of the surveillance procedure review should be expanded.

2.7 Halon Actuation Following Equipment Failure (Unit 1)

On November 19, 1992, at 10:34 p.m., the Unit 1 control room received various fire protection alarms for the plant computer room, under the floor of the plant computer room and the plant computer battery room. A main halon discharge into the computer room had also occurred. There were no individuals in the area at the time of the halon discharge. The control room operators sent two individuals into the area in self-contained breathing apparatus gear. The preliminary search noted no reason for the actuation. The Train C electrical auxiliary building heating, ventilation, and air conditioning system was placed in the smoke purge mode of operation approximately 20 minutes later in order to remove the halon from the area. Portable ventilation equipment was also used to purge the halon from the building. Industrial safety personnel were contacted to perform habitability surveys, and fire protection personnel were contacted to perform an investigation to determine the cause of the halon discharge. About 600 pounds of halon were discharged during the event and all fire protection equipment worked as designed. The plant computer remained on-line during the event.

Further investigation identified approximately 2 inches of water under the computer room floor. The floor in the room is raised above the building floor to allow for air circulation within the computer room. The air handling unit (AHU) drains were discovered to be plugged. The inspectors subsequently determined that there was no routine preventive maintenance to ensure that the drains remain unobstructed. The water accumulation caused AHU 11A to short out, resulting in an actuation of the halon system. Service Request 189083 was issued to troubleshoot and repair AHU 11A. The fan motor was shorted to ground, the contractors for Reheat Coils 1 and 2 had burned contacts (the Contractor Reheat Coil 3 was satisfactory), and three fuses, located in the main fuse block, were blown. All components were replaced on November 28, 1992, and the AHU was subsequently returned to service. Additionally, mechanical maintenance personnel cleaned out the drain lines to ensure proper drain operation.

Two ion detectors are located under the floor of the computer room to provide for fire detection. Following the halon actuation, one detector was found to be mounted too close to the AHU being monitored. The licensee also discovered that a temporary shield was used to reduce the air flow to the detector. The flow rate required for proper detector operation was too high without the shield. The licensee has since removed both ion detectors and plans to replace the detectors with photoelectric detectors. Until the replacement is completed, the licensee initiated hourly fire watches to compensate for the inoperable ion detectors.

2.8 Power Reductions Because of Secondary Side Equipment Problems (Unit 2)

On November 20, 1992, Unit 2 power was reduced to 80 percent to allow for the repair of steam and seal water leaks on Steam Generator Feedwater Pump 23. The power reduction was a conservative action and was not necessary because Startup Feedwater Pump 24, which is normally in standby, could be used to allow the plant to maintain 100 percent reactor power. The unit power reduction was made to increase the margin for a potential reactor trip as part of the licensee's reactor trip prevention program. The startup feedwater pump was started to assist in maintaining an adequate feedwater flow capacity.

The following day, at 6:13 p.m., Startup Feedwater Pump 24 tripped offline with no audible alarms being received in the control room. The lube oil filter differential pressure increased to 25 pounds per square inch differential because the filters had become clogged and lube oil pressure decreased to below the pump trip setpoint. Although this condition was capable of actuating a common trouble alarm in the control room, this trouble alarm was already sealed in and had been continuously lit in the control room. The alarm did not have reflash capability; therefore, the control room was not aware that lube oil pressure had dropped to below the alarm setpoint.

The control room operators manually reduced turbine load until the primary power level was reduced to about 60 percent. A restart of the pump was attempted, but the motor-driven pump tripped on overcurrent. The second trip was the result of water intrusion at the pump motor termination weather-head. The pump is located outdoors. A restart of the pump was successful after maintenance resealed the termination weather-head to prevent further rainwater intrusion. The problem with rainwater intrusion on plant equipment is a long-standing issue that has not been completely resolved (refer to Section 9.3 of this report).

On November 23, 1992, the reactor power was increased to 80 percent following the return of Startup Feedwater Pump 24 to service. The next day, Steam Generator Feedwater Pump 23 was placed on line and the unit returned to full power the same day. An SPR was issued to investigate the events surrounding the pump trip, including the problems encountered with the annunciator being sealed in.

The reduction in power to 80 percent when Steam Generator Feedwater Pump 23 was removed from service may have prevented the unit from tripping offline when Startup Feedwater Pump 24 tripped. If Pump 24 had tripped with the unit at full power, the unit may have tripped offline on low steam generator water level because of a steam flow to feedwater flow mismatch combined with a shrink effect from a rapid decrease in turbine load. The reactor trip prevention program appears to be effective in reducing the number of challenges to the plant.

2.9 Conclusions

Two chemical operators were dismissed for falsifying log sheets. Further review of this incident will be tracked by an unresolved item.

An apparent adverse trend was identified relative to personnel performing work on the wrong component, train, or unit. A further review of these events will be tracked by an unresolved item.

The draining of oil from a reactor coolant pump motor, because of a false high level indication, resulted in motor bearing damage. One of the causes of the event was insufficient knowledge of a standing order which required that a root cause analysis be performed before the removal of the oil.

Four residual heat removal pump trips were noted to have occurred during an 11-day period. None of the trips were considered safety significant; however, two of the trips were the result of incomplete procedures or operator inattention to control board indications. An SPR was not issued until the fourth event. The OSTI, which was ongoing at the end of this inspection, also identified examples of failure to initiate an SPR for conditions adverse to quality. The instances of failing to initiate an SPR constitute an additional example of a violation of the SPR procedure which will be documented in the OSTI inspection report.

A weakness in the requirements for documenting valve manipulations for valves located within an equipment clearance order boundary contributed to a spill of approximately 500 gallons of concentrated sulfuric acid. No personnel were injured.

The criteria for enforcement discretion were satisfied for a licensee identified inadequate surveillance procedure. Although the discovery of the procedure deficiency was positive, this was the third example in recent months in which the discovery of inadequate surveillance procedures resulted in TS 3.0.3 entries. The licensee will make a determination as to whether the scope of the procedure review should be expanded.

A halon actuation was caused by the failure of a computer room air handling unit because of inadequate preventive maintenance on equipment drains. The air handling unit failure may have been avoided if the licensee had been aware of a plugged drain in the vicinity of the air handling unit.

The reduction in power, while Steam Generator Feedwater Pump 23 was out of service, may have prevented the unit from tripping when Startup Feedwater Pump 24 subsequently tripped off line. This was a positive example of the benefits of the reactor trip prevention program. However, the trip of the startup feedwater pump represents the continuation of a long-standing problem with rainwater intrusion into plant equipment.

3 ENGINEERED SAFETY FEATURE SYSTEM WALKDOWN - UNIT 1 (71710)

3.1 Details

A walkdown of an engineered safety feature (ESF) system was performed to independently verify the status of the system. The 125 volt (Class 1E) direct current (DC) power system was inspected. All components were found to be correctly aligned to support plant operation.

The inspectors performed the walkdown using Plant Operating Procedure 1POP02-EE-0001, Revision 5, "ESF (Class 1E) DC Distribution System." At the time of the inspection, Unit 1 was in Mode 5 operation. While in Mode 5, TS 3.8.2.2 required only two (E1A11 and E1C11) battery banks to be operable. All four battery banks and their associated chargers were found in the correct lineup in accordance with Procedure 1POP02-EE-0001 requirements. Selected system parameters were verified within TS required limits, including bus voltage and battery electrolyte levels. The areas inspected were free of loose debris or other conditions (such as unsecured ladders or fire hazards) that could challenge the integrity of the system. All components were clearly labelled.

3.2 Conclusions

All Class 1E DC distribution system components in Unit 1 were correctly aligned to support plant operation. Plant and system cleanliness were being maintained in the areas of the batteries and the battery busses.

4 MONTHLY MAINTENANCE OBSERVATIONS (62703)

Selected maintenance activities were observed to ascertain whether the maintenance of safety-related systems and components was conducted in accordance with approved procedures, TS, and appropriate codes and standards. The inspector verified that the activities were conducted in accordance with approved work instructions and procedures, that the test equipment was within the current calibration cycles, and that housekeeping was being conducted in an acceptable manner. All observations made were referred to the licensee for appropriate action.

4.1 Balance of Plant Diesel Generator Maintenance Activities

Each unit has one BOP DG located in the turbine generator building. The BOP DGs are not safety related but are designed to provide power to critical loads to safely shutdown the secondary side following loss of power events. Each BOP DG consists of a two cycle, 12V type Detroit Diesel engine and a 700 kilowatt (kw), 1800 revolutions per minute (rpm), 480 Volt Kato generator.

One of the tests performed on the two BOP DGs was a load test to ensure that components will operate as designed following a loss of offsite power (LOOP) event. An additional benefit of the load test was to fully exercise the engine by burning off any carbon and oil sludge accumulations from incomplete combustion associated with numerous unloaded DG runs that the machines have been subjected to. The BOP DGs have not been fully loaded since initial plant startup and the practice of running these DGs unloaded can have a long-term detrimental effect on the engine. Oil leakage problems were being experienced because of the unloaded DG runs. Battery cover protection was installed because unburned oil was leaking from the turbocharger area, which is located over one battery bank. A resistive load bank was procured to load the engine to 600 kw for a 3-hour duration. The Unit 1 BOP DG full load tests were performed on November 17, 1992, and the Unit 2 DG load test was performed on November 20, 1992. Further details of the test results are provided in the following sections.

4.1.1 Unit 1 BOP DG

In preparation for the full load test of the Unit 1 BOP DG, selected maintenance activities were performed on the DG components. For example, a flush of the cooling coils and replacement of the fuel filters were performed. A start of the BOP DG was attempted on November 11, 1992, but the engine failed to start twice. At first, the licensee suspected that the cause of the problem was low battery voltage because the batteries were disconnected from the charger during previous mechanical maintenance inspections. A battery equalize charge was performed and the DG was successfully started. The licensee then suspected that the start failures were the result of air in the fuel system because the fuel lines had been drained to change the filters. Further testing and troubleshooting identified a battery cell that had low specific gravity and a small crack. This cell was replaced. Short-term corrective actions completed included revising the work instructions to bleed the fuel lines of air following filter replacement.

The inspectors observed portions of the load test of the Unit 1 BOP DG that occurred on November 17, 1992. Conversations with the system engineer indicated that the 100 percent load test of the BOP DG had never been conducted; however, start-up testing was completed that demonstrated that the DG would carry all required LOOP nonsafety-related loads and respond to actuation signals as designed. The electrical distribution system design prohibited the DG from being tested during plant operation and the lack of shutdown loads prevented an effective test during outages. This test was also designed to provide an assessment of the need to provide load bank testing for all non-class DGs.

Service Request (SR) DB-171649 was developed and implemented to attach monitoring equipment and a vendor supplied resistive load bank to the BOP DG. During the implementation of SR DB-171649, the electrical technicians discovered the need for a modification to the work package to allow installed instrumentation to be used during load testing. The inspectors observed good work practices by the craft personnel.

The Unit 1 BOP DG was operated in accordance with modified Procedure 1POP02-DB-0003, Revision 4, "Balance of Plant Diesel Generator," which was included as an attachment to the service request. The DG was started and initially operated unloaded to verify the load bank was not grounded. The DG was then loaded to around 100 kw and sparks were observed coming from the generator cooling fan and shroud area. The DG was immediately stopped. Subsequent troubleshooting identified that the fan assembly had slipped on the shaft and fan-to-casing rubbing had occurred.

A detailed inspection of the DG was performed. The generator blower hub had shifted inward, the blower plenum was cracked in two places, and the blower hub bolts were worn down because of the movement along the shaft. The cause of the movement was not determined but was suspected to be the result of either vibration or incorrect installation at the factory, or a combination of both. Using guidance provided in SR DB-171630, the rotor was pulled, the fan was replaced, and the fan/rotor assembly was balanced in the machine shop. At the end of the inspection period, the engine remained disassembled for rework.

4.1.2 Unit 2 BOP DG

The licensee experienced problems with the Unit 2 BOP DG failing to start on several occasions between May and September 1992. On September 15, 1992, the 12 fuel injectors of the DG were replaced in an attempt to improve DG reliability. Residual fuel buildup on the internal parts resulted in the sticking of the injectors. The injectors were replaced under SR DB-164951 and were sent to the warehouse for shipment back to the vendor for refurbishment. On September 17, 1992, during the performance of the postmaintenance test for SR 164951, the licensee discovered that the starting solenoid for Bank B of the Unit 2 BOP DG did not engage during the start attempt. The positive terminal stud was loose inside the solenoid. SR 167775 was issued to allow maintenance to replace the 24 volt starting solenoid. During the postmaintenance test on September 24, 1992, the BOP DG failed to start because of a low battery voltage. A 4-hour equalize charge was performed and the BOP DG was successfully started twice on the same day.

On October 12, 1992, the Unit 2 BOP DG failed to start in the manual mode. Problems with the batteries were suspected because both the starters and battery charger appeared to function as designed. A 4-hour charge was performed but this action failed to resolve the problem. All four batteries were replaced in accordance with SR DB-177977. The BOP DG was successfully started 5 days later.

On October 21, 1992, the Unit 2 BOP DG was started to verify operability. The DG shut down prior to reaching full speed. No abnormal conditions or alarms were noted. Several minutes later the DG was successfully started. Instrumentation was installed using SR DB-173323 to trap the shutdown signal. During a subsequent test run on October 23, 1992, the DG started, but the instrumentation appeared to interfere with the voltage control circuitry. Operations personnel could not adjust the output voltage to the correct setpoint. The test instrumentation was removed, the BOP DG was started again, and the test run was successfully completed. Additionally, during a test run on the same day, the Unit 2 BOP DG failed to start. A blown fuse was found in the starting circuit and was replaced. A successful start was completed several hours later.

On October 29, 1992, a test run of the Unit 2 BOP DG was performed with test instrumentation installed to monitor key diesel parameters. During the DG start, the DG speed dipped during the startup process. Several small leaks were identified on the supply and return sides of the fuel system. Also, the fuel hoses showed signs of deterioration. The licensee suspected that the leaks resulted in a loss of fuel in the lines and the introduction of air into the system. This condition would allow for an inrush of air into the DG, resulting in sluggish starts. Previous starts that were completed without success could have been the result of the fuel line leaks and the subsequent air intake into the engine. The fuel line hoses were reworked under SR DB-135380. A postmaintenance test run was successfully completed on November 4, 1992.

On November 20, 1992, the Unit 2 BOP DG was load tested to ensure that the engine would operate with all possible loads connected to the generator. Although the engine was designed to operate at 700 kw, a 600 kw load bank was connected to the DG. The maximum design load was apparently 510 kw; therefore, the load bank exceeded the calculated maximum limit. During the test, the BOP DG would not accept loads above 525 kw because the fuel lines were too small to deliver enough fuel to allow the DG to operate at higher loads. The licensee determined that the DG would handle loads up to and slightly over the calculated maximum load. The licensee plans to change out the fuel lines during the upcoming Unit 2 refueling outage, scheduled to begin in February 1993.

The Unit 1 BOP DG fuel lines were replaced during the DG rebuild that was required because of the November 17, 1992, generator blower failure. The licensee planned to use the load bank on the BOP DG and other similar small DGs on a routine basis. The use of the load bank is indicative of the licensee's increased awareness of the need for additional maintenance and oversight of the plant's nonsafety-related DGs.

4.2 Emergency (EDG) Rework and Unintentional Automatic Start (Unit 1)

On October 24, 1992, EDG 13 was removed from service for its regularly scheduled 18 month inspection. During the EDG outage, Cylinder 6R was replaced, the diesel was unintentionally automatically started during overspeed tests, and large load swings were experienced because of incorrect governor potentiometer settings. The accidental autostart of EDG 13 on November 11, 1992, was identified as an unresolved item, pending NRC review of the licensee's corrective actions for a similar event that occurred on October 15, 1992. EDG 13 was returned to service following rework and surveillance testing on November 19, 1992. Items witnessed by the NRC inspectors included cylinder replacement and postmaintenance testing.

4.2.1 Cylinder Replacement

As part of the 18-month inspection of EDG 13, a boroscope was inserted through the fuel injection nozzle openings to inspect the interior of all 20 power cylinders. If indications of problems are observed, the vendor recommends that the cylinder head be removed and a detailed inspection of the head, piston, and liner be performed. During the inspection, indications of tin transfer were identified on Cylinder 6R. A similar problem was identified on Cylinder 5R of EDG 12 (refer to NRC Inspection Report 50-498/92-29; 50-499/92-29).

SR DG-173247 was issued on October 27, 1992, to replace the Cylinder 6R liner, piston, rings, and gaskets. Additionally, the bottom skirt oil ring and piston pin caps were removed, in accordance with vendor recommended corrective actions, to assist in flushing wear particles from the skirt area. EDG 13 test runs were performed on November 11, 1992 (15-minute test run), and on November 12, 1992 (5 hour test run). Following the test runs, the Cylinder 6R piston pin bolts were inspected and were found to be satisfactory. No significant problems were encountered by the licensee during the cylinder rework.

4.2.2 Unintentional EDG Automatic Start

On November 11, 1992, the licensee started EDG 13 in the emergency mode of operation to allow for overspeed testing in accordance with Procedure OPSP04-DG-0001, Revision 7, "Standby Diesel Generator Inspection (During Shutdown)." EDG 13 tripped on overspeed at 657 rpm, below the acceptance criteria limit of 660 to 666 rpm. The test was performed a second time, and the EDG tripped at 658 rpm. The governor was adjusted for an increased trip setpoint. A standby lineup was started on EDG 13 to allow for a retest of the engine. With the emergency start signal still sealed in because it had not been released, the engine unexpectedly started when the overspeed trip was manually reset. The EDG started immediately after the intake air butterfly valve was opened. The control room operator was instructed by the shift supervisor to stop EDG 13. The operator released the EDG from the emergency mode and then stopped the EDG.

The cause of the event was a combination of personnel error and procedure deficiencies. The EDG was started in emergency to perform the overspeed test, but there was no requirement that the EDG had to be started in emergency. Surveillance Procedure OPSP04-DG-0001 stated to "request plant operations to start and run the engine" prior to the overspeed test. Once the EDG was started in emergency, the emergency signal was not released because the normal operating procedure was not being used in the control room. Additionally, the butterfly valve was reset by a mechanic without proper authorization and out of sequence from the standby lineup requirements. The shutdown butterfly valve is mechanically latched to the overspeed governor. When the valve is reset, it also resets all the logic for the overspeed fuel shutdown valve and the overspeed governor. If a start signal is locked in when the valve is reset, as was the case in this instance, the EDG will restart.

Short-term corrective actions implemented included revising Surveillance Procedure OPSP04-DG-0001 to provide additional instructions to start the EDGs in the test mode, rather than the emergency mode, when the overspeed test is performed. Other short-term corrective actions planned included counselling the individuals involved. Long-term corrective actions being considered included performing a design review to determine whether the emergency mode can be automatically released when an emergency stop condition is initiated. An SPR was issued to perform an indepth investigation of the event. Since the EDG was inoperable at the time of the event, the accidental automatic start signal was not considered an inadvertent ESF actuation; therefore, this event was determined not to be reportable.

A similar event occurred on October 15, 1992, when EDG 12 unintentionally started because the emergency pull-to-stop button was reset prior to the emergency start signal being released. Following NRC review of the event, a Notice of Violation (498;499/9229-02) was issued on November 25, 1992. Therefore, because the licensee has not fully implemented their corrective actions for a previous, similar event, this event is not being considered for enforcement action.

Following the event of October 15, 1992, NRC inspectors reviewed the logic diagrams for the EDGs. Drawing 5Q159Z42100-1, Revision 11, "Standby Diesel Generators Logic Diagram," did not accurately reflect the sequence of events that occurred when EDG 12 automatically started. This drawing discrepancy was reported to the licensee. Further review by the licensee was performed and the elementary drawings were found to be incomplete in describing the actions of the control circuits. However, the vendor supplied drawings, used during maintenance work on the EDGs, were found to be accurate. The Design Engineering Department will initiate design change documents and update electrical and logic drawings for the EDG control circuits to ensure that they accurately reflect actual functions. This work is planned to be completed in April 1993.

4.2.3 Governor Readjustments

On November 12, 1992, during the EDG 13 analysis run following maintenance and modifications to the EDG, large swings in load were observed. Generator load was noted to have fluctuated up to 1500 kw during the event. EDG 13 was stopped and a vendor representative was called in to assist in troubleshooting the governor control circuits. The governor control system is comprised of two closed loops, the electrical loop and the mechanical backup control loop. The electrical loop employs a load feedback transducer, a speed feedback transducer, and a servo amplifier. The servo amplifier controls the amount of fuel going to the EDG based on the input of voltages from the transducers. In order to achieve loop stability, it is necessary to adjust the dynamics between the controller commands and the engine response. During troubleshooting under SR DG-126374, it was determined that the initial fine tuning adjustments after the recent maintenance had resulted in the reset potentiometer being set somewhat high. This resulted in the governor response being under damped which caused the governor to react too quickly to load changes. This overshooting effect of an underdamped governor is referred to as ringing. With the vendor representative's assistance, the two potentiometers were adjusted to establish a more optimum level of EDG performance. The licensee successfully identified and corrected the problem causing the EDG load swings.

4.3 Conclusions

The reliability of the BOP DGs has been adversely affected because of the number of start failures. The licensee has initiated actions to improve the reliability of the DGs, including the use of a load bank to functionally test the DGs and increasing the start frequency to verify operability.

The licensee implemented a vendor-recommended modification because of tin transfer associated with Cynlinder 6R of EDG 13. The unintentional automatic start of EDG 13 was caused by a procedure deficiency and human error.

5 BIMONTHLY SURVEILLANCE ACTIVITIES (61726)

5.1 Logic Train Functional Test (Unit 2)

TS Table 4.3-1 requires that each logic train be tested at least once every 62 days, on a staggered test basis. Therefore, either Train R or S is tested each month. On November 9, 1992, the solid state protection system (SSPS) logic Train S was tested in accordance with Surveillance Procedure OPSP03-SP-0005S, Revision 2, "SSPS Logic Train S Functional Test." The test was performed by Unit 2 licensed operators. To comply with the reactor trip prevention program, the unit supervisor monitored the primary test performer's actions. During the performance of the surveillance procedure, problems were encountered with the automatic input function test pushbutton. The test performer had to depress the test pushbutton several times for selected logic checks until the logic test for each circuit was completed. The test was subsequently completed with no logic test failures.

If the test pushbutton had failed during the surveillance, the licensee would have stopped the test and restored the equipment to operable. An alternate test method was available that would have allowed the use of a temporary test switch; however, this option was not approved on the date of surveillance performance. If the surveillance had been suspended, the licensee had approximately 3 weeks to perform the test before the expiration of the TS allowed grace period. The licensee has experienced problems with the SSPS logic Train S test equipment since April 1992 (refer to NRC Inspection Report 50-498/92-24; 50-499/92-24). The licensee plans to initiate SSPS test equipment repairs during the upcoming Unit 2 third refueling outage, which is scheduled to begin in late February 1993. Because of the potential for a reactor trip, the licensee decided not to attempt repairs during Unit 2 power operation. Since the test has to be performed every other month, the surveillance procedure has to be completed once more prior to the unit outage.

5.2 Essential Chilled Water Pump Reference Values Measurement (Unit 1)

The inspector observed the restoration portion of Procedure 1PSP03-CH-0006, Revision 7, "Essential Chilled Water Pump 11C Reference Values Measurement." Reactor plant operators were referencing the working copy of the procedure throughout the surveillance. The inspector verified that the temporary test gauges were calibrated and verified the accuracy of the data sheet calculations. The system engineer was present during the performance of the test and verified that the results were acceptable.

5.3 Power Range Neutron Flux Analog Channel Operational Test (Unit 2)

On November 18, 1992, the inspector observed the performance of an ACOT on Power Range Neutron Flux Channel 4. This surveillance test was performed in accordance with Procedure OPSP02-NI-0044, Revision 0, "Power Range Neutron Flux Channel IV ACOT (NI-0044)." This procedure verifies and reestablishes accuracies of the trip setpoints and alarms for power range neutron flux high and low setpoints as well as neutron flux high positive rate. This procedure was performed in a systematic and careful manner. The personnel involved included an apprentice, and the journeyman's explanation of the ongoing work was good. Independent verification and self-verification were stressed during the performance of the work.

5.4 Conclusions

During the performance of the surveillance tests that were witnessed, the inspectors observed good supervisory and system engineer oversight and good self-verification by the test performers.

6 COMPLEX SURVEILLANCE - UNIT 1 (61701)

An inspection of selected surveillance activities was performed to ascertain whether functional testing of the more complex safety-related systems is in conformance with regulatory requirements. The inspection included a detailed review of the applicable procedures, including a comparison of the procedures to the requirements of TS, the Updated Final Safety Analysis Report, and design documents such as piping and instrument diagrams and logic drawings. Surveillance test performance was witnessed to ensure that the procedures were properly implemented by the licensee. Two complex surveillance tests were witnessed and reviewed by the inspectors.

6.1 EDG 11 Loss of Offsite Power - Engineered Safety Features Actuation Test

On November 30, 1992, a test of Train A components was performed in accordance with Surveillance Procedure 1PSP03-DG-0013, Revision 5, "Standby Diesel LOOP-ESF Actuation Test." The procedure provided instructions to simulate a LOOP in conjunction with an ESF safety injection signal and to verify: (1) the deenergization of Emergency Bus E1A and load shedding from the bus, (2) the automatic starting of EDG 11, (3) the capability of EDG 11 to synchronize with the offsite power source while the generator was loaded upon restoration of offsite power, transfer its load to the offsite power source, and be restored to its standby status, and (4) the capability of the generator to reject a load of greater than or equal to 785.3 kilowatts. The automatic functions of selected systems were also verified during the test, such as the automatic start of pumps on the ESF signal. The test procedure also verified that all automatic diesel generator trips, except engine overspeed, generator differential, and low lube oil pressure, were automatically bypassed following the LOOP-ESF signal.

The components being tested performed as designed and no equipment failures were observed. EDG 11 started within the required time interval of 10 seconds, all loads were shed from Emergency Bus E1A, and all loads required following a LOOP-ESF reconnected to the bus. All nonemergency trip signals were actuated one at a time but none caused EDG 11 to trip off line. The test was performed by the Unit 1 operations shift crew. The test was effectively performed and crew communications were noted to be good. Operations personnel limited outside activities to avoid distractions and maintained effective control over the equipment being tested.

6.2 Emergency Diesel Generator 11 Loss of Offsite Power Test

On November 30, 1992, a LOOP test of the Train A components was performed in accordance with Surveillance Procedure 1PSP03-DG-0007, Revision 5, "Standby Diesel 11 LOOP Test." The test consisted of: (1) simulating a LOOP condition, (2) verifying that the ESF Bus E1A deenergized and that loads were shed from the bus, (3) verifying that the EDG 11 automatically started on the LOOP signal, (4) ensuring that all loads required to operate following a LOOP sequenced onto the bus, and (5) ensuring that selected component cooling water system valves repositioned as designed. The automatic load shed bypass and the manual load shed reinstatement features of the load sequencer were also demonstrated to be operable.

During performance of the test, all components operated as designed. Essential Chiller 11A stopped following an automatic start on low chilled water temperature. There was not enough load on the chilled water system to keep the chiller operating; however, this had no effect on final test results. As with the LOOP-ESF test, the Train A LOOP test was performed by Unit 1 operations personnel. Test performance and crew communications were determined to be good.

6.3 Complex Surveillance Results Review

The inspector performed an examination of the completed surveillance tests to determine whether the tests results satisfied the surveillance tests acceptance criteria. In addition the test package was reviewed to verify that all appropriate steps had been signed off; deficiencies or anomalies, if any, were documented; retests, if any, were documented; and the results had been approved.

The test packages for tests 1PSP03-DG-0013 and 1PSP03-DG-0007 contained the data package cover sheet, the surveillance data sheets and various valve and load lineup sheets. In general, all the required signoffs and comments were entered on the various data package sheets. There were some minor omissions; however, these omissions were not related to any of the acceptance criteria that demonstrated satisfactory completion of the tests. Test 1PSP-DG-0013 was missing the test date on the cover sheet. Step 6.16.2 of Test 1PSP-DG-0007 recorded voltage ranges in kilovolts when the range was specified in volts. Step 6.4.1 of 1PSP-DG-0007 required that the circuit breaker for MOV-0004A be opened after the valve is closed and a note be made in the remarks section that the circuit breaker had been opened. The valve was closed; however, the note was not entered in the remarks section of check sheet 5. Restoration step of 1PSP-DG-0007 required a note be entered in the remarks section of check sheet 11 stating that the circuit breaker to MOV-0004A was closed. The note was not entered.

6.4 Conclusions

The ESF-LOOP and LOOP tests were effectively performed. The tests were completed with no significant problems or equipment failures being encountered. Licensee personnel who performed the test were knowledgeable of the test and its effect on the unit. Plant operators maintained good control over the plant during equipment manipulations. Communications between the test performers were good.

7 REFUELING ACTIVITIES - UNIT 1 (60710)

7.1 Unit 1 Outage Status

The Unit 1 fourth refueling outage began on September 19, 1992. A 62-day outage was planned, with a completion date of November 20, 1992. At the beginning of the inspection period, Unit 1 was in "no mode," with all fuel removed from the reactor containment building. The unit entered Mode 6 on November 12, 1992, and core reload was completed 4 days later. The unit ended the inspection period in Mode 5 and about 3 weeks behind schedule. The delays were attributed, in part, to problems with the refueling equipment and unanticipated rework of the EDGs. Major activities completed during the inspection period included loss of offsite power and safety injection surveillance testing and reassembly of the high pressure turbine.

All major modifications that were scheduled for implementation during the outage have been installed. The modifications that were installed to fulfill NRC commitments included: (1) relocation and labelling of the RHR flow and temperature controllers and meters on the auxiliary shutdown panels; (2) replacement of selected EDG Agastat relays from unsealed to sealed type relays; (3) upgrading the feedwater isolation valve hydraulic system; (4) rerouting the reactor head vent piping; (5) elimination of the containment spray additive tanks and installation of trisodium phosphate baskets inside the containment building; (6) deletion of the RHR suction valve automatic closure interlock; and (7) replacement and revision of the toxic gas monitors and actuation circuitry. EDG modifications completed included: (1) the installation of new delivery valve holders, injector assemblies, and high pressure lines; (2) installation of new lube oil crossover lines; and (3) elimination of the intercooler expansion joints, the installation of vent valves, and addition of pipe supports to eliminate the essential cooling water system waterhammer problems. Other modifications completed included: (1) installing main steam drain orifices to minimize secondary side steam demand; (2) modifying the high pressure turbine horizontal joint and gland seals; and (3) upgrading the stator cooling water and hydrogen systems.

7.2 Bent Springs on Unit 1 Fuel Assemblies

During the Unit 1 core offload, 20 fuel assemblies were observed to have deflected springs. The bent springs were associated with one batch of fuel assemblies and were determined to have been caused by the use of incorrect drawings by a Westinghouse subcontractor. Corrective actions planned at that time included repair of 17 fuel assemblies. The remaining three fuel assemblies were not reloaded into the core but were scheduled to be repaired and used in a future core load. In late October 1992, a nonconforming plant change form was generated to repair the damaged holddown springs. Special tools were assembled to compress the spring packs, to laterally move the spring to prevent it from hooking on a cusp during the spring pack release, and to deform the spring tang away from the spring direction of travel. This work was performed by Westinghouse personnel under SR FH-173360 and was completed on November 8, 1992. Justification For Continued Operation 92-690 was developed to justify continued operation of Unit 2 for the bent spring conditions identified during core offload in Unit 1. The licensee has requested that Westinghouse evaluate whether this event is reportable under 10 CFR 21 requirements. This evaluation was incomplete at the end of the inspection period.

7.3 Replacement of the Feedwater Booster Pump (FWBP) Impellers

Three 50 percent capacity, motor-driven, single stage FWBPs are connected in parallel to provide the steam generator feedwater pumps with their required suction pressure. During the Unit 1 first refueling outage, pitting and impingement were identified on the FWBP impellers. The licensee suspected the impeller indications were the result of operating the pumps at low system pressure (pump runout conditions) for an extended length of time during unit startup testing. During the first refueling outage for Unit 2, similar problems were not observed when the FWBP impellers were inspected. This was attributed to the Unit 2 startup taking less time than the Unit 1 startup.

During the Unit 1 fourth refueling outage, the FWBP 11 impeller was inspected using a boroscope. Pitting, impingement, and small cracks were observed and the licensee decided to pull and replace the impeller. Because of the damage observed on the FWBP 11 impeller, the licensee decided to pull and replace the impellers of FWBPs 12 and 13 without performing a boroscope inspection.

At the end of the inspection period, the FWBPs had not been fully restored. The licensee plans to ship the old impellers to the vendor for refurbishment. During the next refueling outage for Unit 2, the licensee plans to inspect FWBPs 21, 22, and 23. The licensee also plans to perform an evaluation to generate long-term corrective actions needed to prevent recurrence.

7.4 Repairs to Alternate Charging Isolation Valve

On September 7, 1992, Unit 1 declared a Notification of Unusual Event as a result of unidentified reactor coolant system leakage in excess of the TS limit of 1 gallon per minute. The source of the leak was subsequently determined to be the Alternate Charging Isolation Valve CV-MOV-006 (refer to NRC Inspection Report 50-498/92-26; 50-499/92-26 for additional details). During this outage, the licensee implemented repairs to the valve. There was no steam cutting identified and the repairs were limited to replacing the valve bonnet gasket. In addition, as a result of MOVATS testing that was conducted during this outage, the gears in the valve actuator were changed to provide additional thrust.

7.5 Auxiliary Feedwater System (AFW) Pipe Elbow Replacement

As a result of Information Notice 92-07, "Rapid Flow-Induced Erosion/Corrosion of Feedwater Piping," which alerted the licensee of a problem at Catawba-2 involving rapid flow-induced erosion/corrosion of auxiliary feedwater piping, the licensee expanded their Erosion/Corrosion Inspection Program to include sections of the AFW system piping. The licensee's program identified an elbow in the AFW system with an area approximately 3 by 10 inches which indicated wall thickness less than the manufacturing tolerance of 87.5 percent of the nominal thickness of 0.500 inches. The thickness found was 0.409 inches. The minimum thickness based on design pressure allowed by the ASME Code is 0.375 inches. No thickness measurements were below the required design minimum thickness prescribed by the Code. The area was identified by ultrasonic measurements at 1-inch grid intersections. This elbow is on the preheater bypass line to Steam Generator B in the unisolable portion of the line. Upstream and downstream components were inspected, with no measurements below manufacturing tolerance noted. The corresponding elbows on the AFW preheater bypass lines to the other three steam generators were also inspected and no measurements below manufacturing tolerance were identified. The licensee decided to replace the elbow during the ongoing outage.

The removed elbow was analyzed by the licensee's Materials Technology Division to determine the cause of the wall thinning. Cross sections of the elbow were cut and measured directly for diameters and wall thickness. The magnetite layer on the inside surface was intact and there was no evidence from surface examination or microscopy of any erosion/corrosion reaction. Optical emission spectroscopy confirmed that the elbow was made from ASTM A106, Grade B steel. The cause of the thin section was determined to be a manufacturing defect which occurred during the original manufacture of the elbow. Additional components in the AFW system will be identified for inspection during the next outage in both units.

7.6 Accidental Fall into the Reactor Refueling Cavity

On November 17, 1992, a decontamination technician slipped and fell into the reactor refueling cavity in Unit 1 and was immersed up to his neck in water. The technician was lowering a scavenger filter into the reactor cavity in preparation for cleaning of the lower internals storage area. The technician leaned out over the water in an attempt to lower the scavenger filter as far as possible from the wall. Although the individual was wearing a safety belt, he slipped and fell into the pool. The individual pulled himself out of the pool with the help of a health physics technician. He was immediately removed from the area, nasal swipes were taken, and he was escorted to the egress point. Direct frisking of the upper body, arms, and hands revealed no detectable contamination. The individual showered and then passed the personnel contamination monitor five times. The individual was then given a whole body count and a urine sample was taken. It was subsequently determined that the technician did not receive an uptake.

A Radiological Occurrence Report was generated to provide a formal investigation of the incident. As part of the corrective actions, the licensee issued Health Physics Night Orders to ensure the use of the refueling bridge to access a desired location and prohibit leaning out over the pool.

7.7 Reactor Containment Building Walkdown

Just prior to the Unit 1 Mode 4 entry on December 6, 1992, the inspectors performed a detailed walkdown of the Unit 1 reactor containment building to ensure that the area was ready for plant operation. All items, with few exceptions, had been removed from the building and the reactor containment building appeared generally clean and free of loose debris or paper such as danger tags. All scaffolding and other tools also had been removed. Some radiologically controlled access equipment and several bags of potentially contaminated protective clothing were left, but these items were scheduled to be removed just prior to Mode 2 (Startup) operation.

7.8 Conclusions

All major modifications planned for the Unit 1 fourth refueling outage were completed as planned. A manufacturing defect in an elbow in the AFW system was identified during the licensee's inspections for erosion/corrosion. A technician fell into the reactor refueling cavity but was not injured or contaminated. A postrefueling walkdown of containment was performed and the building was clean and ready for plant operation.

8 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS AND DEVIATIONS (92702)

8.1 (Closed) Enforcement Action 498;499/91-55: Failure to Maintain Complete and Accurate Records of Preventive Maintenance on Safety-Related Valves

On April 5, 1991, two apparent violations were identified during NRC Inspection 50-498/91-12; 50-499/91-12 involving falsification of records in violation of 10 CFR 50.9(a). Records of preventive maintenance on safety-related Valves C1SIMOV0039C and 2R172XCV0091A were not complete and accurate. For the first valve, the work instructions required that 14 packing rings be replaced. Although the completed record indicated that all rings were replaced, only five packing rings were actually replaced. For the second valve, the work instructions required that 15 packing rings be replaced, but in fact only 7 of the rings were replaced. Again the record was incorrect. The first event was reported by a contractor employee who stated that he falsified the work document at the direction of his foreman. The second event was discovered during the licensee's investigation of the first event. The second event was determined to have been a previous incident of falsification by the contractor employee's foreman.

On October 22, 1991, an enforcement conference was held to discuss the apparent violations. A Notice of Violation and Proposed Imposition of Civil Penalty, EA-91-055, were issued on December 12, 1991. The licensee responded to the Notice of Violation on January 7, 1992, and concurred that the violation occurred.

The rings of packing for both valves were reworked. Site access for the responsible foreman and for the contractor manager in whose group this work was performed was revoked. In order to prevent recurrence, the licensee conducted site-wide meetings to review management expectations concerning quality and standards of integrity and accuracy in documentation. A policy setting forth standards of professionalism and performance was issued and additional meetings with all employees were held to reinforce the requirement to comply with the policy. The inspector reviewed training records which indicated that all plant personnel received training in professionalism and standards of performance. The licensee's actions appeared to have assured that personnel were fully aware of the licensee's standards of professionalism and integrity and of the accountability for adhering to those standards.

8.2 <u>(Closed) Violation 499/8868-07: Failure to Identify and Correct a Procedure Error</u>

Violation 498/8868-07 was intended to be closed in NRC Inspection Report 50-498/92-13; 50-499/92-13, however, Violation 499/8868-07 was not documented as having been closed in this inspection report.

8.3 <u>(Closed) Violation 498;499/9121-03: Failure to Maintain Security DG in Operational Condition</u>

On August 8, 1991, a functional test of the lighting/security DG was performed, with unsatisfactory results. The output breaker failed to close because the breaker was not fully racked into position. No specific activity, such as breaker design or previous maintenance, was identified which could be directly attributed to the failure of the breaker to close. The licensee suspected the cause of the event was improper restoration of the breaker by nonlicensed operators following previous maintenance activities. The failure of the lighting/security DG to be capable of starting and accepting the load of the security system upon receipt of a start signal was a violation of the physical security plan. Corrective actions taken included enhancing the circuit breaker operating procedure and adding the event to the operators' lessons learned training program.

A similar event occurred on September 12, 1991, when Emergency Diesel Generator 23 failed to connect to Emergency Bus E1C because the output breaker was not properly racked into position (Notice of Violation 499/9125-02 was issued for this event). One of the corrective actions taken in response to the September 12, 1991, event included the development of instructions which require that electrical breaker continuity checks be performed whenever a breaker (480 volt and greater) is racked out for any reason. The instructions were added to the Operations Policies and Practices Manual in October 1991. This policy, if it had been in place prior to August 1991, may have prevented the first event from occurring. Violation 499/9125-02 was subsequently closed in NRC Inspection Report 50-498/92-08; 50-499/92-08. The corrective actions taken in response to the two events appear to be appropriate.

8.4 <u>(Closed) Violation 499/9224-02: Failure to Have Appropriate Procedures</u>

On June 3, 1992, licensed plant operators in Unit 2 failed to properly restore the control room envelope to its standby condition following a planned system actuation because an air makeup supply flow control damper was left out of position. The operators left the damper open, instead of placing the damper in the required position of closed, because of a deficient restoration procedure. Additionally, a surveillance procedure was incorrectly signed off as having been satisfactorily completed even though the damper was left out of position. Corrective actions taken included revising the deficient procedure and reviewing similar procedures to ensure proper damper restoration following system actuations. No additional procedure deficiencies were identified during the review.

9 ONSITE FOLLOWUP OF WRITTEN REPORTS OF NONROUTINE EVENTS (92700)

9.1 <u>(Closed) Licensee Event Report 498/91-014: Erratic Containment Extended Range Pressure Channel Output</u>

On April 20, 1991, with Unit 1 at full power, the licensee discovered that one of two containment extended range pressure channels was indicating an erroneously high value. A review of the computer historical records indicated that the channel had been inoperable in excess of the TS allowed outage time. The transmitter was determined to be providing an erratic output signal and a control card was subsequently replaced. No generic failure mechanism was identified from a review of the nuclear plant reliability data system. Additionally, the failure rates for the affected components were consistent with industry experience. The components are currently being monitored under the trending program established at the facility to identify potential failure trends.

9.2 <u>(Closed) Licensee Event Report 498/92-006: Discovering of Four AFW Flow Control Valves in the Closed Position Contrary to Procedures</u>

On March 18, 1992, while Unit 1 was at 33 percent power, the licensee discovered all four AFW flow control valves in the closed position. The valves were closed on March 14, 1992, following a reactor trip, and were not reopened after securing the AFW system. The licensee initiated a voluntary licensee event report after determining the valves would have opened as required and the system would have performed its intended safety function. The licensee's corrective actions included the following:

- Adding steps to the reactor trip response procedure (OPOP05-EO-ES01, Revision 3) and plant startup procedure (OPOP03-ZG-0005, Revision 0) to ensure that the AFW flow control valves are opened.

- Conducting licensed operator training on the event to emphasize proper panel walkdowns and turnover practices. Additionally, an Operations Bulletin was issued to describe the event and actions that could have prevented its occurrence.

- Adding of the four AFW flow control valves to each shift's safety system checklist.

The inspectors determined that these corrective actions were acceptable.

9.3 <u>(Open) Licensee Event Report 499/92-003: Manual Reactor Trip</u>

On February 24, 1992, Unit 2 was manually tripped from 100 percent power to prevent an automatic low-level steam generator reactor trip. The turbine driven steam generator feedwater pumps had experienced several speed control fluctuations earlier in the day and, at 6:10 p.m., Steam Generator Feedwater Pump 21 was observed to have a decreasing speed. Manual speed control was attempted with no success and the reactor was manually tripped with steam generator levels at 47 percent and decreasing.

The licensee determined that the event was caused by rain water leaking through expansion joints in the turbine building roof and into the electrohydraulic control cabinet. The cabinet contains the common controls for the three steam generator feedwater pumps. Modifications 89007 (Unit 1) and 89008 (Unit 2) were implemented to provide watertight sealing of the turbine deck roof. The inspectors verified the installation and performance of the watertight seals. The inspectors verified that the licensee had completed all identified corrective actions.

During this inspection period, the site experienced heavy rains. The plant was observed to have several areas that leaked rainwater. The Unit 1 turbine building was noted to have numerous leaks. This leak may have been the result of the high pressure turbine being disassembled, which created temporary holes in the roof of the building. This licensee event report will remain open pending further NRC review of the licensee's ability to eliminate rainwater intrusion into the plant.

9.4 (Closed) Licensee Event Report 499/92-006: Unplanned ESF Actuation

On May 22, 1992, the component cooling water (CCW) outlet valve from Residual Heat Removal Heat Exchanger 2C opened for no apparent reason. This action resulted in a CCW header pressure decrease, which caused CCW Pump 2A to automatically start. Despite visual examinations and functional testing, the cause of the event was not determined. The licensee suspected the solenoid which maintains the valve shut lost power momentarily, which allowed the valve to open to its fail safe position. The event has not recurred since then.

At the time of the actuation, the licensed control room operators did not recognize this event as an ESF actuation; therefore, the event was not reported within the 4-hour time limit established by 10 CFR 50.72. Following further review by the licensee, the event was determined to be reportable and was reported to the NRC Operations Center about 9 hours late. Further discussion of the licensee's failure to make timely reports to the NRC was provided in NRC Inspection Report 50-498/92-26; 50-499/92-26.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

L. Baca, General Supervisor, Warehousing
R. Balcom, Director, Nuclear Security
H. Bergendahl, Manager, Technical Services
T. Blevins, Supervisor, Procedure Control
C. Bowman, Administrator, Corrective Action Group
K. Christian, Manager, Nuclear Plant Operations Department
R. Dally-Piggott, Engineering Specialist, Licensing
D. Denver, General Manager, Nuclear Assurance
J. Gruber, Director, Independent Safety Engineering Group
J. Johnson, Supervisor, Quality Assurance
T. Jordan, General Manager, Nuclear Engineering
W. Jump, General Manager, Nuclear Licensing
W. Kinsey, Vice President, Nuclear Generation
D. Leazar, Manager, Plant Engineering
M. Ludwig, Manager, Nuclear Training
M. McBurnett, Manager, Integrated Planning and Scheduling
T. Meinicke, Manager, Planning and Assessment
M. Pacy, Manager, Design Engineering
G. Parkey, Plant Manager
J. Pinzon, Senior Licensing Engineer
J. Sharpe, Manager Maintenance

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 December 7, 1992. 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.