APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/91-30 Operating License: NPF-76
50-499/91-30 NPF-80

Dockets: 50-498
50-499

Licensee: Houston Lighting & Power Company (HL&P)
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: November 16 through December 20, 1991

Inspectors: J. I. Tapia, Senior Resident Inspector
R. J. Evans, Resident Inspector

Approved: A. T. Howell 1-17-92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted November 16 through December 20, 1991 (Report 50-498/91-30; 50-499/91-30)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of written reports of nonroutine events, followup on inspection followup items and one unresolved item, operational safety verification, maintenance observations, engineered safety feature system walkdown (Unit 2), and preparation for refueling activities (Unit 2).

Results: A continuing negative trend in diesel generator reliability was observed. Several different EDG problems occurred during the inspection period, including fuel subsystem problems. Corrective action was taken to repair the specific problems; however, the ongoing problem with the cracking of delivery valve holders is still being evaluated and a permanent repair is still pending (paragraph 4.1).

There were several problems that occurred during the performance of maintenance and testing activities because of inadequate work instructions, failure to follow procedures, or weaknesses associated with craft workmanship. An instance of failure to follow an approved procedure resulted in a Notice of Violation (paragraph 4.7). Collectively, these problems are indicative of a need for improvement in the implementation of plant maintenance and testing.

Two events required Unit 1 power to be reduced to allow for repairs. The repair of the steam generator feedwater Pump 11 speed control circuit and repair of a steam leak on the high pressure turbine required unit power reductions (paragraphs 4.2 and 4.6).

A wiring error was found during a functional test of the Anticipated Transient Without Scram Mitigation System Actuating Circuitry (AMSAC) in Unit 2. The wiring error would not have prevented AMSAC from performing its intended function if a valid signal had been generated; however, it represented a difference in the design of the test circuitry between the two units which was previously not known. The licensee suspects that the error occurred when the AMSAC circuity was installed and added to the elementary drawings (paragraph 4.8).

A crack in the Unit 1 essential cooling water system developed during this inspection period. The magnitude of the crack would not have prevented the system from performing its intended function. This new crack resulted from residual weld stresses on a repair to a previous crack brought on by dealuminization. This crack is bounded by an existing Justification for Continued Operation (JCO). The licensee's long-term resolution of this problem will be evaluated during future inspections (paragraph 4.9).

The containment spray system for Unit 2 was inspected, and it was found correctly aligned to support plant operation (paragraph 6). The second Unit 2 refueling outage was completed on December 18, 1991. With few exceptions, all major work activities were completed (paragraph 7).

A list of acronyms and initialisms is provided as an attachment to this report.

DETAILS

1. PERSONS CONTACTED

P. Appleby, Training Manager
C. Ayala, Supervising Engineer, Licensing
R. Balcom, Director, Quality Assurance
M. Chakravorty, Executive Director, NSRB
R. Dally, Engineering Specialist, Licensing
D. Denver, Manager, Nuclear Engineering Department
D. Hall, Group Vice President, Nuclear
W. Humble, Section XI Supervisor, Plant Engineering Department
W. Jump, Manager, Nuclear Licensing
C. Kern, Senior Staff Consultant
W. Kinsey, Vice President, Nuclear Generation
D. Leazar, Manager, Plant Engineering Department
R. Lovell, Manager, Technical Services
D. Mathews, Supervisor, Nuclear Contracts
M. McBurnett, Manager, Integrated Planning and Scheduling
M. Pacy, Division Manager, Design Engineering Department
W. Randlett, Security Manager
D. Sanchez, Director, Maintenance
T. Underwood, Director, Independent Safety Engineering Group
M. Wisenburg, Plant Manager

The above licensee personnel attended the exit interview conducted on December 20, 1991. In addition to the above, the inspectors also held discussions with various licensee, maintenance, and contractor personnel during this inspection.

2. PLANT STATUS

Unit 1 began the inspection period at full power operation. On November 29, 1991, a power reduction was commenced to allow for repair of a steam leak on the south end of the high pressure turbine. A balance weight cover inspection port, located above Gland 1, had developed a leak. Power was reduced to about 20 percent and the turbine was taken off line for about 1 1/2 hours while repairs were made to the port. After repairs were completed, power ascension began and the unit was returned to full power on December 1, 1991. Unit 1 remained at full power until December 7, 1991, when another power reduction was initiated to allow for repair of the Main Feedwater (MFW) Pump 11 speed control circuit. A tachometer in the speed control circuit had failed. Reactor power was decreased to 20 percent and the main turbine generator was left on line. The tachometer was replaced with one obtained from MFW Pump 21, which was not operational at that time. Reactor power was increased and full power operation was reached the next day. The unit remained at full power through the end of the inspection period.

Unit 2 began the inspection period in Mode 5 (Cold Shutdown) operation for a refueling outage. The refueling outage began on September 14, 1991. Unit 2 remained in Mode 5 until December 4, 1991, when Mode 4 (Hot Shutdown) was achieved. Mode 3 (Hot Standby) was entered on December 9, 1991, and Mode 2 (Startup) was entered 2 days later. Criticality was also achieved on December 11, 1991, and Unit 2 entered Mode 1 (Power Operation) 3 days later. The Unit 2 turbine generator was synchronized to the grid (main generator output breaker closed) on December 16, 1991, for an 8-hour "soak" at 10 percent electrical power. The next day, Unit 2 entered Mode 2 operation with the turbine generator off line to balance the turbine and repair the main turbine hydrogen seal oil system. On December 18, 1991, Unit 2 again entered Mode 1 operation and the turbine generator was synchronized to the grid later the same day, thus ending the second refueling outage. Power escalation occurred over the next several days, while startup tests were performed at selected power levels. Unit 2 was at about 70 percent power operation at the end of the the inspection period and was continuing the power ascension.

3. INSPECTOR FOLLOWUP

3.1 Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

3.1.a (Closed) Licensee Event Report (LER) 50-498/91-003: Unplanned Engineered Safety Features (ESF) Actuation Due to a Radiation Monitor Actuation

On January 27, 1991, Unit 1 was in its third refueling outage with no fuel in the reactor vessel. Radiation Monitor C1RA-RT-8034 (control room intake air) in the electrical auxiliary building (EAB) exhaust air duct went into high alarm. The high alarm resulted in an ESF actuation which caused the control room heating ventilating, and air conditioning system to go to the recirculation mode of operation. The high alarm cleared after approximately 2 minutes. The redundant Radiation Monitor RT-8033 did not detect any increase in airborne activity and remained in the normal range.

The licensee performed grab samples of the control room atmosphere and no increase in activity was identified. Work Request RA-134135 was initiated to investigate and repair the problem. The licensee could not determine the cause of the actuation, although noise problems have previously contributed to spurious alarms on radiation monitors. The licensee suspected that the sample pump was creating noise problems. Corrective actions taken by the licensee included replacement of the pump. Postmaintenance testing was performed with satisfactory results. The redundant monitor was verified to be operable and within calibration. The licensee's corrective actions were found to be appropriate. This LER is closed.

3.1.b (Closed) LER 50-498/91-010: Manual ESF Actuation Due to a Toxic Gas Alarm

On April 4, 1991, the Unit 1 control room received a toxic gas high concentration alarm. The operators manually placed the control room ventilation into the recirculation mode. The alarm was caused by a failed printed circuit board. The event was originally considered to be not reportable; therefore, the notification to the NRC was 4 days late. LER 50-498/91-010 did indicate that the notification was late but failed to discuss why the delay occurred and did not address any corrective actions to prevent recurrence. This LER was previously reviewed (NRC Inspection Report 50-498/91-19; 50-499/91-19) but was left open pending inspector followup of corrective actions for the delay in reporting.

The licensee has since submitted Revision 1 to LER 50-498/91-010 to the NRC. The revision addressed the delay in the notification to the NRC. Additionally, guidance defining manual ESF actuations and reportability requirements has been provided to all control room operators. The licensee's corrective actions were considered appropriate. This LER is closed.

3.2 Followup (92701)

3.2.a (Closed) Inspection Followup Item (IFI) 498/9034-01: Emergency Diesel Generator 11 Bearing Rework

During a previous inspection, the as-found condition of the generator end outboard bearing clearance on EDG 11 was not within the limits established by the vendor manual. Investigation revealed that the measurement technique utilized by the licensee differed from the method used by the vendor. In addition to the clearance issue, babbit (antifriction alloy) was identified in the oil beneath the bearing. This was determined to have been caused by rubbing between the oil ring and the outside diameter of the bearing. The licensee determined that the bearing was acceptable for continued use. The licensee planned to remove the bearing during the next outage in order to blend away or smooth the rubbed areas. This action was tracked as an IFI (498/9034-01).

Work Request (WR) DG-118095 was issued to rework the outboard bearing of EDG 11. The activities consisted of reworking the oil ring grooves in the outer diameter of the bearing and removing babbit on the outer groove. The work was completed in February 1991, and EDG 11 was returned to service. IFI 498/9034-01 is closed.

3.2.b (Closed) IFI 498/9125-01: Corrective Actions Taken to Ensure Timely Notification of Events

Two LERs were issued concerning reportable events that were not reported to the NRC Operations Center within the required time intervals. LER 50-498/91-002 was issued because of an unplanned safety injection (SI) actuation. The event was not reported in a timely manner because the operators did not fully understand NRC guidance on unanticipated or unplanned ESF actuations. LER 50-498/91-010 was issued because of a manual ESF actuation due to a toxic gas alarm. The event was reported late because the operators did not originally consider a manual actuation of an ESF system reportable in accordance with 10 CFR Part 50.72.

Corrective actions taken by the licensee included revising the LERs in question and submitting guidance to plant operators about ESF actuations and reportability requirements. Both LERs have been revised and submitted to NRC to address the causes of the delay in reporting and corrective actions taken

Additional guidance was developed for operators that described the reportability policies, listed the actions required by control room personnel, and provided examples of reportable or nonreportable ESF actuations. The licensee had implemented the corrective actions that were stated in the revised LERs. This IFI is closed.

3.2.c (Closed) Unresolved Item 498/9101-04; 499/9101-04: Inconsistent Surveillance Procedures

During a previous inspection, inconsistency was observed between the Units 1 and 2 containment hydrogen recombiner calibration procedures. The Unit 1 procedure was different from the Unit 2 procedure in several places. Administrative control of procedure changes was governed by Procedure OPGP03-ZA-0002, Revision 19, "Plant Procedures." Procedure OPGP03-ZA-0002 stated that consistency between similar procedures for Units 1 and 2 shall be maintained. Although the two procedures were not consistent, the differences had minor safety significance. Additionally, this example appeared to be an isolated incident and not indicative of a programmatic problem. Corrective actions taken by the licensee included combining the two unit procedures into one common procedure. Any additional inconsistent procedures that are identified will be corrected under the procedure upgrade program. This unresolved item is closed.

4. 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 inspectors visited the control rooms on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS, and overall personnel performance within the control room were in accordance with NRC requirements. Tours in various locations of the plant were also performed to observe work activities and to ensure that the facility was being operated in conformance with license and regulatory requirements.

The following paragraphs provide details of specific inspector observations during this inspection period.

4.1 EDG Problems (Units 1 and 2)

On November 20, 1991, during the performance of a surveillance test on EDG 12 to determine operability following preplanned maintenance, a fuel oil leak was identified on Cylinder 9L. The engine was secured and the licensee initiated an investigation. Two cylinders were later identified as having cracked delivery valve holders. This event was initially identified as a nonvalid failure; however, after further evaluation for reportability, the event was classified as a "no test." The licensee determined that, with operator intervention, the affected cylinder could have been removed from service, thereby effectively stopping the leak and allowing the EDG to perform its design function. This "event" was reclassified as a "no test" since the EDG was shutdown at the operators' discretion.

Problems have occurred with leaks on high pressure fuel lines in the past. On November 20, 1990, a fuel oil leak on the nozzle for Cylinder 1L on EDG 23 was reported as a valid failure because of a fire hazard from fuel oil spraying on the hot exhaust header. On October 25, 1991, a delivery valve holder cracked and leaked on Cylinder 9L of EDG 21. This event was originally classified as a nonvalid failure because credit could be taken for operator intervention to remove the affected cylinder from service. HL&P management reclassified the event as a valid test because the EDG ran loaded for at least one hour and was shutdown at the operator's discretion. On October 30, 1991, a nozzle assembly started spraying fuel oil on Cylinder 5R on EDG 22. This event was classified as a valid failure because the leak caused an atomized spray close to the exhaust header and was considered a fire hazard. The event was reported to the NRC. Subsequent investigation by the system engineer disclosed that, although atomized spray was present, there was no spray coming into contact with the exhaust header or any other heat source. Again, the licensee determined that the EDG could perform its design function with operator intervention.

In evaluating these events for reportability, the licensee utilized a methodology for identifying leaks which could result in an EDG from performing its safety function. Two fuel oil leak scenarios were identified which could cause an EDG failure. In one instance, the fuel oil leak would create a fuel source for a fire which would ignite and cause sufficient damage to render the EDG inoperable. In the other, the fuel oil leak would be of sufficient size to deplete enough available fuel oil to prevent the EDG from completing the required 7-day design basis run. In the latter scenario, operator intervention to rack out the affected cylinder was never considered.

As a result of operator intervention, the licensee considered that two of the three events discussed above have been misclassified. The inspectors concurred with the licensee's conclusion. On the basis of the reclassification, there has been one valid failure in the last 20 valid tests of EDG 22. The number of valid failures in the last 100 valid tests is less than four; therefore, the testing frequency for EDG 22 has been returned to once per 31 days. There have been no valid failures in the last 20 valid tests of EDG 21 and the number of valid failures in the last 100 valid tests is less than four; therefore, the testing frequency for EDG 21 remains at once per 31 days. The licensee plans to submit a report describing the reclassification of two previous EDG failure events as "valid tests."

The cracking of the delivery valve holder is a continuing problem and, although the events have been reclassified as "valid tests," the licensee is pursuing a design change to replace the delivery valve holders with a new Cooper-Bessemer Owners' Group recommended design or an equally acceptable modification of the existing delivery valve holders. The modifications are scheduled to be made no later than the next refueling outage in each unit.

On November 23, 1991, during a postmaintenance run of EDG 22, three out of four of the 10L injector pump pedestal retaining bolts were found loose. None of the fuel connections were ruptured and no fuel leaks occurred. EDG 22 was secured from its run and a station problem report was initiated. The problem was discovered while the EDG was out of service; therefore, this event was classified as a "no test." It was subsequently determined that the inoperable fuel injector pump would not have affected the capability of EDG 22 to perform its safety function if challenged in an emergency. Previous analyses have shown that an EDG may be operated indefinitely on 18 cylinders without adversely affecting diesel internal components or preventing the fulfillment of the safety function. The review of historical work documents disclosed that these bolts had never been removed or worked on since plant startup. Although unlikely, this condition could cause the relaxation of bolt torque, resulting in the potential failure of the fuel injector for the affected cylinder. In order to address this concern, the licensee commenced a verification of adequate pedestal bolt torque for all EDG engines. All bolts were found to meet the minimum requirement of 50 foot-pounds torque. The licensee believes that the loose bolts resulted from inadequate torquing during the original installation. Nevertheless, the investigation being conducted to address the station problem report will consider the potential for bolt relaxation. The inspectors will continue to monitor the licensee's analysis of this event.

On December 6, 1991, EDG 22 was started in the emergency mode following release of an equipment clearance order. When EDG 23 was released from the emergency mode, the EDG tripped with no test mode trip signals indicated. The EDG was restarted twice on December 7, 1991, without tripping. The EDG performed satisfactorily during a one hour surveillance run and was declared operable. Also on December 7, 1991, EDG 21 was started. When the EDG 21 was released from the emergency mode, the EDG tripped with no test mode trips indicated. EDG 21 was restarted and functioned properly. The operability test was performed (one hour run) and the EDG was declared operable. The causes of these events were not immediately known. Further troubleshooting of the EDGs will be performed during the next regularly scheduled train outages. A supplemental report will be submitted identifying the causes and necessary corrective actions. These two events have been classified as nonvalid failures since the EDGs operated satisfactorily in the emergency mode and if challenged, would have performed their safety function. The testing frequency for both remained at once per 31 days.

On December 12, 1991, the EDG 11 output breaker tripped open during the performance of an operability surveillance test at full load. EDG 11 was started in accordance with the surveillance procedure and attained rated speed, voltage, and frequency within the required time limits. After the EDG was at full load, three attempts were made to raise reactive load. The reactive load could not be increased above 3400 kilo volts-amperes reactive (kVAR) using the voltage adjust switch. Several minutes later, the reactive load meter pegged high, the voltage meter increased to about 5.0 kilovolts, and the generator output breaker tripped open on instantaneous directional overcurrent. The event was classified as nonvalid failure, which requires a special 30-day report to be submitted to the NRC. The event was considered a nonvalid failure because the problems were experienced only after the EDG operation was released from the emergency to the test mode. EDG 11 would have operated satisfactorily and performed its safety function in the emergency mode. Troubleshooting of the EDG was performed using Service Request DG-149159. A defective instantaneous prepositioning board was found. A new board was obtained, calibrated, and installed. A postmaintenance test was satisfactorily completed the same day.

When in the emergency mode, the instantaneous prepositioning board functions to bring the EDG up to the designed emergency bus voltage of approximately 4.16kv without the need for operator action. Once released from the emergency mode, relay contacts on the board change state and the current path bypasses the fixed voltage regulator. The cause of the EDG 11 event was attributed to oxidation on relay contacts within the instantaneous prepositioning board. This oxidation created a resistance which did not allow an increase in kVAR and voltage. Corrective actions taken included board replacement and a plant engineering evaluation. The evaluation will determine if a more suitable relay contact material is needed for the operating environment. This action is planned to be completed in February 1992. Since there has been one valid failure in the last 20 tests and one valid failure in the last 100 tests, the testing frequency remained at once per 31 days for EDG 11.

The inspectors noted that there were two previous EDG performance problems that were attributed to instantaneous prepositioning board problems. On November 19, 1991, EDG 22 was started and experienced load swings during the test mode of operation. The EDG ran satisfactorily during the emergency mode but once paralleled, the frequency and voltage readings were erratic. Troubleshooting began but was terminated on November 23, 1991, when bolts were noticed to be loose on the cylinder 10L fuel injector pump (as previously described in this section). Troubleshooting continued on December 15, 1991, and a defective instantaneous prepositioning board was discovered. High resistance was measured across a relay on the circuit board. The board was subsequently replaced and the EDG was returned to service. On September 4, 1991, a nonvalid failure of EDG 22 occurred. The failure was also attributed to the instantaneous prepositioning board which was operating intermittently. The board was returned to the vendor for failure analysis. Results were not available at the end of the inspection period. The licensee suspected that the problem was due to the nonsafety-related relay on the circuit board not being correctly sealed at the factory. The licensee's corrective actions will be monitored by the resident inspectors.

4.2 Pressurizer Spray Valve Repairs (Unit 2)

During this inspection period, a review of the licensee's actions associated with the rework of the Unit 2 pressurizer spray valves was performed. The pressurizer spray valves and electrical heaters are used to assist in pressure control of the reactor coolant system (RCS). The spray valves are also used to circulate coolant through the pressurizer for boron concentration equalization. Two automatically controlled, air-operated valves with remote manual overrides are used to control pressurizer spray from two RCS cold legs. The Unit 2 spray valve, 2-RC-PCV 655C, was previously noted by the licensee to be partially open. A second spray valve, 2-RC-PCV 655B, operated without any problems. The ability of the licensee to repair Valve 2-RC-PCV 655C was limited because the spray valves cannot be isolated during power operations; therefore, the RCS had to be depressurized to remove the valve.

WR RC-131612 was written in December 1990 to disassemble, repair, and reassemble the Unit 2, Loop 1 Spray Valve 2-RC-PCV 655C when conditions permitted. Work began in October 1991, during the second Unit 2 refueling outage. The investigation of the cause for the sticking valve was documented on WR RC-131612 and Request For Action 91-1756. Indications which were found included the galling of the bearing to the shaft at the bearing cover (outboard end of shaft). The shaft also showed signs of wear in the packing gland area. Measurements of bearing shaft and bearing cover were taken and indicated no loss of material. The bearing was replaced and shaft was buffed to remove sharp edges. The valve was reassembled and the packing gland was torqued down. A new method and lower value for final torque was supplied by the vendor and implemented in the field. Work was completed November 21, 1991. The licensee was unable to conclusively determine the cause of the spray valves not going fully shut, and they are still investigating cause.

After increasing RCS pressure, it was determined that 2-RC-PCV 655B was leaking by its seat. Valve 2-RC-PCV 655B had not been worked on during the outage. RCS pressure was reduced and 2-RC-PCV 655B was disassembled and inspected in accordance with WR RC-111520. The seating assembly was found worn and was replaced. Valve 2-RC-PCV 655B was reassembled and RCS pressure was again increased. However, Valve 2-RC-PCV 655C was not functioning properly and was causing too much spray into the pressurizer. RCS pressure was decreased again to allow rework on Valve 2-RC-PCV 655C. It was discovered that, during valve reassembly, the valve was not in the full closed position. The actuator arm zero marks were found 180 degrees out of alignment. Following a briefing by a vendor representative, the actuator was disassembled and the workers properly oriented the actuator arm on the spline shaft. The reason the valve was initially installed incorrectly was attributed to inadequate work instructions. The work instructions did not clearly specify the method of assuring proper rotation of the valve actuating lever mechanism. The vendor manual was also deficient in terms of providing detailed guidance. Other contributing factors to the problem included: the repair of Valve 2-RC-PCV 655C lasted almost 1 month, which caused more than one crew to complete the assembly of the actuating arm (this was the first time this unique type of valve was worked on), and quality control verified the ball-to-shaft assembly but not the shaft-to-actuating arm assembly.

Plant restart from refueling was delayed several days in order to allow for rework on the spray valves. A station problem report was written to investigate all activities associated with both spray valves. Corrective actions planned include: rebuilding the valves during the next refueling outage and incorporating lessons learned from the work activities into the applicable procedures. The licensee is considering plans to obtain a mockup to train future workers. The two Unit 2 spray valves were in service at the end of the inspection period and were functioning properly.

4.3 Battery E2D11 Failed Surveillance (Unit 2)

On November 25, 1991, a 2-hour load profile test was performed on Battery E2D11 in accordance with Surveillance Procedure 2PSP06-DJ-0004, Revision 2, "125vdc Class 1E Battery Service Surveillance Test." During the load test, the post on Battery Cell 7 failed and the test was terminated. The licensee decided to rework all connections on Battery E2D11 and jumper out Cell 7. Temporary

Modification T2-DJ-91-0024 authorized the jumper and the cell was electrically disconnected from the battery in accordance with Service Request 151035 two days later.

Prior to the surveillance test, corrosion or oxidization buildup on Batteries E2B11 and E2D11 was observed during the performance of the weekly surveillance tests. WRs were written to clean, but not disconnect the battery connections and to apply an oxygen inhibitor preservative as necessary. The bus bars were disconnected, cleaned, and replaced as necessary. When the test was performed on Battery E2D11, Cell 7 failed when 422 amperes were applied to the battery. A postfailure inspection indicated that the failure was possibly caused by inadequate surface contact between the bus bar and terminal post. During the work on Battery E2D11, adequate surface contact between the bus bars and the battery posts were not verified (not required by procedure or the vendor manual) prior to the service test. Better instructions or worker knowledge on how to verify the cross section surface contact on the posts may have prevented battery cell failure. After the battery failed, all bus bars were replaced and adequate post-to-bar contact was verified. The service and intercell resistance tests were reperformed with satisfactory results. Battery Cell 7 was left in the bank for seismic purposes and is scheduled for replacement by May 1992. The Battery E2D11, Cell 7, failed, in part, because of inadequate workmanship or procedural guidance. Additional training and procedure enhancements are necessary to clearly describe the requirements for ensuring good electrical connections. The licensee has issued a special problem report for this event.

In 1989, two cells (49 and 46) were jumpered out on Battery E2B11. A safety evaluation was performed that demonstrated that the battery would remain operable with 2 out of 59 cells removed from the battery bank. The cells were subsequently replaced about 1 year later. A calculation was performed in October 1991 to determine how many cells can be out of service on each safety-related battery with the battery still capable of performing its safety function. Battery E2B11 can have 2 cells out of service while Battery E2D11 can have 3 cells out of service. Battery E2D11 is identical to Battery E2B11 in model, type, and year of manufacture (1977). The Battery E2D11 load profile is less demanding than that of Battery E2B11. Both batteries have a past trend of corrosion or oxidization buildup. The licensee has taken steps to improve the reliability of the batteries, with satisfactory results. For example, Battery E1A11, Cell 54, currently has a low cell voltage. Actions were taken by the licensee and the voltage of Cell 54 was trending upward. Additionally, an improvement in voltage levels of Battery E2B11 has also been noted. Actions taken to improve the reliability of the batteries appear appropriate. These actions include performing calculations to determine how many cells can be out of service and trending the condition of the batteries.

4.4 Repair of Steam Leak (Unit 1)

On November 28, 1991, a steam leak developed on the Unit 1 main turbine generator. The balance weight cover access port on the south end of the high pressure turbine above Gland 1 was leaking steam and water. On November 29, 1991, power was reduced and the turbine was taken off line to eliminate the leak and to allow for cover replacement. WR TM-149105 was issued to perform the repair. The turbine was off line for approximately 1 1/2 hours. The plant returned to 100 percent power 2 days later. About the same time, a different (north end) balance weight cover was repaired on the Unit 2 high pressure turbine (Unit 2 was in Mode 5 at that time). A similar problem had previously developed with the Unit 2 balance weight cover, and a temporary repair was implemented. The licensee implemented a permanent repair during this outage. Both Units 1 and 2 turbines have since been returned to service without additional leaks being observed with the balance weight covers.

4.5 Secondary Sump Leak Rate Calculations

While testing the Proteus Sump Level Monitoring program, the licensee discovered the secondary containment sump volume held approximately 65 gallons of water instead of 40.6 gallons which was used in the calculations. This resulted in a nonconservative error in the conversion factor of percent to gallons. TS 4.4.6.2.1.b states that reactor coolant system (RCS) leakage shall be demonstrated to be within each of the limits established by monitoring the containment normal sump inventory and discharge at least once per 12 hours. The NRC was notified on December 1, 1991, because the licensee believed that the requirements of TS 4.4.6.2.1.b were not being satisfied.

Further investigation determined that the event was not reportable since there are no TS requirements pertaining to secondary sump levels in determining RCS leakage rates. The licensee determined that leakage into the containment normal sump has been monitored as required by TS. The secondary sump calculation error did not affect a reading required by TS; therefore, the error was not considered reportable. A different method, utilizing Procedure OPSP03-RC-0006, "Reactor Coolant System Inventory," is performed to ensure compliance with TS 3.4.6.2 for unidentified RCS leakage. The licensee took corrective actions to update the conversion factors in the manual calculation procedure and the Proteus computer, which automatically performs the calculation.

4.6 Main Feedwater (MFW) Pump Turbine Trip (Unit 1)

On December 3, 1991, MFW Pump 11 tripped on electrical overspeed (106 percent). The startup feedwater pump automatically started to maintain Unit 1 at 100 percent power. Troubleshooting was performed in accordance with WR FW-149721 to determine the cause of the trip. A defective tachometer was found in the speed control circuit which caused the overspeed condition. Reactor power was decreased to allow for the repairs to be made. There were no replacement parts in the warehouse, so a tachometer was obtained from MFW Pump 21 in Unit 2. Unit 2 was in Mode 4 at that time and MFW Pump 21 was not needed. The tachometer was replaced in the MFW Pump 11 speed control circuit. MFW Pump 11 was tested with satisfactory results and was returned to service.

4.7 Loss of RCP Motor Lubrication (Unit 2)

On December 4, 1991, a loss of lubricating oil to RCP Motor 2C occurred, resulting in overheating of the lower radial bearing of the motor. Service Request RC-152227 was being implemented to eliminate air leaks into the RCP

Motor 2C oil reservoir sight level gauge. The portion of the service request that was being implemented (Step 3.13) involved coordination with the control room operators and electricians to run the pump for 30 minutes and then to verify that the oil levels were within tolerance. The tolerance specified in the service request for a running motor was plus or minus 1/4 inch from the center line of the oil level gauge. The electricians found the oil level for the lower motor bearing at plus 3/8 inch. They then attempted to drain oil from the reservoir; however, the service request did not specify the exact methodology to be utilized for draining the reservoir. They proceeded to drain the oil into the oil collection system by opening two valves (PO-0267 and PO-0271) downstream of a quick disconnect, which is normally utilized to fill and drain the oil.

The oil collection system has an oil drain tank located outside containment and is isolated by containment isolation valves. On November 6, 1991, a local leak rate test was performed in accordance with Procedure OPSP11-PO-0001, Revision 2, "Local Leakage Rate Test, Penetration M-75, RCP Oil Return Line." Step 6.6.8 required that, after the local leak rate test was completed, the piping was to be depressurized by opening and closing the test connection (PO-0236). This step was not performed and the piping between the containment isolation valve (PO-0217) and Valve PO-0271 remained pressurized.

When the electricians attempted to adjust the motor oil level by opening Valve PO-0271, the unexpected pressure was relieved back into the motor and caused oil flow to the lower radial bearing to be reduced. The bearing temperature increased and a low oil level alarm was received in the control room. The pump was then secured. Subsequent review of computer records indicated that bearing temperature went as high as 240°F. Normal operating bearing temperature is about 132°F and vendor specifications require securing the pump at 190°F. The licensee commenced changing out the lower radial bearing and labyrinth seal after consultation with the vendor.

The loss of lubrication to the RCP lower radial bearing can be attributed to the failure to perform a step during the performance of local leak rate test procedure, which is considered a violation of TS 6.8.1.a (499/9130-01). Additionally, there was a weakness associated with the service request because of a lack of specificity of the work instructions on how to lower the lubricating oil level. The service request referenced maintenance Procedure OPMP05-RC-0004, Revision 1, "Reactor Coolant Pump Motor Removal, Inspection, and Replacement." Step 6.9.4 of that procedure stated, "add or remove oil as required, to bring oil to correct level."

4.8 Discovery of Incorrectly Wired Motor Operated Valve (Unit 2)

In response to the Notice of Violation and Proposed Imposition of Civil Penalty (Enforcement Action 91-074), the licensee committed to perform an end-to-end test of AMSAC during each refueling outage. On December 12, 1991, Procedure OPEP07-AM-0001, Revision 0, "AMSAC Actuation Test Trains A, B, C and D," was performed on the Unit 2 AMSAC system for the first time. Procedure OPEP07-AM-0001, Section 7.2.5.1, provided instructions to verify that Steam Isolation Valve 2-AF-MOV-0143 opened and would not close following initiation of the AMSAC test signal. This step attempted to verify that blocking function of the manual close signal was operating as designed. During performance of Step 7.2.5.1, Valve 2-AF-MOV-0143 went closed when the control room hand switch was taken to the close position, contrary to the procedure step expectations. Upon reaching a closed position, Valve 2-AF-MOV-0143 immediately began opening. This resulted in an Auxiliary Feedwater (AFW) Pump 24 trip on overspeed (electrical) because Throttle Valve 2-AF-MOV-514 had insufficient time to adequately reduce steam flow to the AFW pump turbine. AFW Pump 24 was restarted 10 minutes later and it operated as designed.

A review of the applicable elementary drawings was performed, and the review indicated that the valve operated as designed in response to a valid actuation signal. However, the review also revealed that Relay INAR23 Contact H-J was incorrectly wired in parallel with the K827 and K855 relays. Relay INAR23 should have been wired in series with the two relays for correct operation of the circuit. The three relays open a dedicated set of contacts which block closing of Valve 2-AF-MOV-143 if any of three conditions existed: Train A safety injection (SI) signal, low-low level in any steam generator (Train A), or AMSAC actuation signal. The Unit 1 circuit was noted to be correctly wired. The licensee determined that the Unit 2 circuit was incorrectly wired because the design drawing was in error. However, the equipment would have operated as designed following a valid actuation signal; therefore, the AFW Pump 24 was considered operable at that time.

Document Change Notice DCN-ED2127 was issued to revise the erroneous elementary diagram (9EPN05-01 #2, Revision 5, "Isolation Relay Panel RR138") and Service Request AM-111673 was issued to implement the change. AFW Train D was removed from service for modification of the circuitry on December 16, 1991, and it was returned to service the next day. The AMSAC actuation test was again performed as a postmaintenance test on Train D and the results were satisfactory. The cause of the drawing error was not immediately known; however, the licensee suspected the design error occurred when the AMSAC was installed and added to the elementary drawings. A station problem report was issued to investigate the wiring error. A safety concern did not exist because the equipment would have fulfilled its intended function if a valid actuation signal (SI, AMSAC, or steam generator Low-Low level) had initiated the AFW circuitry.

4.9 Component Cooling Water Heat Exchanger Outlet Piping Weld Crack (Unit 1)

On December 13, 1991, a through-wall crack on the 30-inch essential cooling water (ECW) outlet pipe from component cooling water Heat Exchanger 1B was identified in Unit 1. The crack was initially 6 inches in length on the pipe surface and approximately 8 3/4 inches in length on the pipe interior diameter. Field measurements indicated the leakage to be about 1 1/2 gpm. The crack is associated with a weld repair that was made in September 1991 of a through-wall crack that was determined to have been caused by dealloying of the weld filler metal and a preexisting defect. As a result of the original crack, the licensee had generated JCO 910273, which was previously reviewed by the NRC and determined to provide sufficient basis for continued operation. Nevertheless, in order to obtain a better understanding of the failure mechanism, the licensee elected to cut the weld out and perform metallurgical analysis.

The licensee conducted a Plant Operations Review Committee meeting on December 13, 1991, to address the question of whether the new crack was bounded by the existing JCO. On the basis of the fact that the JCO provides for a maximum allowable leak of 8 gpm into the Mechanical Auxiliary Building (derived from the flooding analysis), as well as the ability to provide sufficient cooling with up to 100C gpm leak per ECW train, the leakage rate from this crack was bounded. In order to address the issue of stress levels, a test was conducted to identify if water hammer was occurring. Plant engineers were stationed throughout the extent of the ECW system during pump starts and stops to watch for transient loads. The maximum system pressure noted was 90 psi upon pump start and 57 psi after the system stabilized. The maximum differential temperature was about 20°F. On the basis of these measurements and on the fact that no transient loads were identified, plant design engineers concluded that the total bending stresses have all been accounted for and that the stresses, including the safe shutdown earthquake load, are less than 26.1 Ksi as originally calculated. Utilizing this stress value and referring to JCO 910273, with a 1.33 safety factor applied, a through-wall crack with a length of 23 inches can be tolerated without a potential for the plastic collapse of the pipe.

Subsequent to the stress evaluation, crack length increased to 10 3/8 inches. On the basis of the rapidity with which the crack developed and on its growth during testing, HL&P metallurgical engineers and a welding expert from Stone & Webster Corporation, brought in to independently assess the crack, determined that the failure of the weld repair was caused by high residual stress resulting from the large repair window of 2 by 11 inches. The weld crack is not expected to grow beyond this area of residual weld stress and will, therefore, not exceed 11 inches. To assure this, plant operators are visually monitoring the cracked weld area on a per-shift basis. The licensee plans to implement a short-term repair of the crack during the next train outage, presently scheduled for the second week of January 1992. Long-term corrective actions are also being considered and will include a determination of the cause of the residual weld stresses. The inspectors will continue to monitor the licensee's progress.

4.10 Main Generator Hydrogen Leaks (Unit 2)

During the startup of Unit 2 following the refueling outage, the unit experienced trouble with the generator hydrogen seal oil system. The seal oil system is used to lubricate the seals and prevent hydrogen from escaping from the generator, without introducing an excessive amount of air and moisture into the generator. The air side of the seal oil system is separated from the hydrogen side of the seal oil system to preclude introducing air and moisture into the hydrogen side. During the plant startup, hydrogen was noted to be leaking from the generator. Additionally, temperature and pressure transients were being observed by plant operators. On December 16, 1991, the Unit 2 main turbine generator was tripped off line because of low generator hydrogen pressure. Troubleshooting of the air side seal oil system began. Seal oil problems identified included an incorrectly installed in-line filter, and incorrectly set pressure regulators and relief valves. The turbine was returned to service on December 18, 1991, following repairs. After the turbine generator was returned to service, the seal oil system was in operation and not fluctuating in temperature and pressure. The identified problems with the seal oil system were indicative of the need for improved implementation of balance-of-plant equipment maintenance.

4.11 Potential Waterhammer Event (Unit 2)

On December 20, 1991, during a start of condensate Pump 21, a 10-inch diameter recirculation to Condenser 21 pipe shifted, which caused a 1-inch fill line weld to break. Three 50 percent capacity, motor-driven condensate pumps are provided to deliver condensate to the suction of the feedwater system. Minimum flow recirculation lines are provided at each pump discharge to protect the pump. The recirculation lines discharge to the main condenser. A 1-inch fill line is connected to each of the three recirculation lines to fill the lines with water to reduce the potential for waterhammer events. The source of water to fill the recirculation lines is the secondary makeup tank via the condenser makeup pumps. Hangers support the recirculation line as necessary but are designed to allow for some line movement.

When condensate Pump 21 was started, the recirculation line shifted more than expected in the horizontal direction. The fill line, which is perpendicular to the recirculation line, could not shift as far as the recirculation line shifted and the weld broke at the fill line connection. Pipe hanger damage occurred as a result of the excessive pipe movement. The condensate Pump 21 recirculation line has experienced more movement than the other two lines because of the greater length of the line. A station problem report was written to investigate the event, including engineering review of the line and support design of all recirculation lines. At the end of the inspection period, repairs to the weld and pipe supports were in progress. Although the most likely cause of this event was a waterhammer transient, the licensee was still investigating the cause as of the end of the inspection period.

Conclusions

Several equipment problems and failures (both safety-related and nonsafety-related) occurred as a result of inadequate procedures, failure to follow procedures, or poor workmanship. Collectively, these problems are indicative of a need for improved performance in the area of maintenance.

A continuing negative trend in EDG reliability was observed. Although the licensee has taken many short-term actions and is in the process of developing and implementing long-term actions for fuel subsystem problems, EDG problems are recurring.

NRC will evaluate the effectiveness of the licensee's actions to correct dealloying of ECW system weld filler metal pending the licensee's development of long-term corrective actions.

5. 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.

5.1 Preventive Maintenance (PM) of Temperature Channel

On December 9, 1991, PM IC-1-HC-86008414 was observed. This procedure was an 18-month maintenance activity that was performed on the reactor containment fan cooler (RCFC) Cooling Coil VHX0002 outlet temperature channel. Channel 1-HC-T-9674 was checked in accordance with Procedure OPMP08-HC-9674, Revision 0, "RCFC Cooling Coil Outlet Temperature Channel Calibration." All components were left within acceptance criteria limits and no concerns were identified.

5.2 Transmitter Calibration

On December 4, 1991, a calibration check of the control room supply air Cleanup Unit 11C Fan VFN009 Outlet Flow Transmitter C1-HE-FT-9589 was performed. The transmitter provides high and low flow alarms for Cleanup Unit 11C. The work was being performed in response to Service Request HE-119125, which was written in June 1991, because the transmitter output would not change. At that time, the instrument was found to have no output. During the performance of Service Request HE-119125, on December 4, 1991, the instrument was found to be in tolerance and was left in operation. The instrument was checked in accordance with Procedure OPMP08-ZI-0002, Revision 3, "Pressure Transmitter or Differential Pressure Transmitter Calibration." The technicians could not determine the reasons why the transmitter was previously considered inoperable, but suspected the the transmitter was not properly valved into service. The technicians experienced several problems during performance of the calibration. The test gauge used was extremely sensitive because of the need to measure a value under a 1-inch water column. The readings were affected by ambient air flows and movement of the test connection tubing. Slight tubing leaks were present, which affected the readings of the test gauge. However, the inspectors determined that the values measured and recorded were accurate readings.

6. ENGINEERED SAFETY FEATURE SYSTEM WALKDOWN - UNIT 1 (71710)

A walkdown of a Unit 2 containment spray system was performed to independently verify the status of the system. The valves, control switches, and electrical power supplies were compared to the positions required by the piping and instrument diagrams and Procedure 2POP02-CS0001, Revision 3, "Containment Spray Standby Lineup." All valves, control switches, and power supplies were found in positions to support plant operation.

During the Unit 2 second refueling outage, major modifications were performed on the containment spray system. The sodium hydroxide spray additive tanks and support systems were removed from the system. The sodium hydroxide was drained from the three tanks, the tanks were abandoned in place by installing flanges and blanks in the downstream piping of the tanks, selected cables were deleted, the main control room panels were modified, and procedures were updated. The spray additive tanks were deleted because: (1) the potential damage from the NaOH (a caustic) was more costly than the benefits of scrubbing post-LOCA (Loss of Coolant Accident) iodine from the water inside containment, (2) the tank outlet valves occasionally leaked and introduced sodium into the refueling water storage tank and the RCS, and (3) the Westinghouse Owners Group program identified that caustic was not required to be added for effective iodine removal to limit post-LOCA doses, and sufficient removal occurs using refueling water storage tank water for containment spray (with no chemicals added). There still was need to neutralize the acidic post-LOCA water which would accumulate on the containment floor. A passive system utilizing trisodium phosphate was added inside containment so the sump pH would be maintained at a minimum of 7.5. The passive system consists of six stainless steel baskets, located on the containment floor, which contains the trisodium phosphate.

The modifications to the system were inspected. All recommended changes that were inspected were correctly installed (or deleted) and appeared to be of high quality. However, the inspectors observed that four of six flanges installed to isolate the three tanks leaked. The licensee intiated work requests to repair the flange leaks. The nitrogen supply to the tanks was not disconnected but was isolated from the tanks by manually operated valves. Plant procedures, and TS, were revised to incorporate the modifications.

Conclusion

The Unit 2 containment spray system was inspected and all components were aligned to support plant operation. Selected modifications made to the system were inspected and implemented in accordance with the design.

7. PREPARATION FOR REFUELING (UNIT 2) (60705)

A review was conducted of the completed outage scope for the Unit 2 second refueling outage. The purpose of this review was to determine if any significant activities that were scheduled to be completed were deferred. The licensee's original outage scope was reviewed and documented in NRC Inspection Report 50-498/91-25; 50-499/91-25. The licensee completed all the major items listed in that report with the exception of the following items:

- Twelve dynamic MOV tests were deleted from the scope of the outage. During the available work window for these tests, the test equipment failed and could not be repaired in time to avoid a delay in the outage. These 12 dynamic tests will be completed in the next unit refueling outage to meet NRC commitments.
- The main condenser tube cleaning was deleted from the outage scope. Because of equipment problems, the contractor selected for this activity was unable to produce the unit rates (number of tubes per unit time) necessary to complete the job within the available schedule. The failure to complete this job may result in a main generator power output reduction of a few megawatts during hot weather operation.

° Rather than replace the reactor water makeup pump as originally planned, modifications were made to improve their reliability. The modifications included the installation of a 4-inch recirculation line and the installation of isolation valves.

Conclusion

The Unit 2 second refueling outage started on September 14, 1991, and concluded with final breaker closure on December 18, 1991. The planned outage duration was 82 days. With few exceptions, all major work activities planned were completed during the refueling outage.

8. EXIT INTERVIEW

The inspectors met with licensee representatives (denoted in paragraph 1) on December 20, 1991. The inspectors summarized the scope and findings of the inspection.

ATTACHMENT

LIST OF ACRONYMS

AFW	auxiliary feedwater
AMSAC	Anticipated Transient Without A Scram Mitigation System
CFR	Code of Federal Regulations
ECW	essential cooling water
EDG	emergency diesel generator
ESF	engineered safety feature
gpm	gallons per minute
HL&P	Houston Lighting & Power Company
IFI	inspector followup item
JCO	justification for continued operation
LER	licensee event report
LOCA	loss of coolant accident
MFW	main feedwater
NaOH	chemical compound-sodium hydroxide
NRC	U.S. Nuclear Regulatory Commission
RCFC	reactor containment fan cooler
RCP	reactor coolant pump
RCS	reactor coolant system
SI	safety injection
TS	Technical Specification
vdc	volts-direct current
WR	work request