APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/91-34 Operating License: NPF-76
50-499/91-34 NPF-80

Dockets: 50-498
50-499

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: December 21, 1991, through February 1, 1992

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

Approved: William B. Jones 2/21/92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted December 21, 1991, through February 1, 1992 (Report 50-498/91-34; 50-499/91-34)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of written reports of nonroutine events at power reactor facilities, followup on corrective actions for violations and deviations, onsite followup of events at operating power reactors, operational safety verification, monthly maintenance observations, and bimonthly surveillance observations.

Results: In the areas of operations and maintenance, continuing balance of plant equipment problems resulted in two reactor trips and several delays in startup and operation. These problems were indicative of a need for improved material condition of the plant (Sections 2, 4.1, and 5.2). A Unit 2 trip resulted from a failed diode in the rod control system. The cause of the failure of the diode is not known; however, the licensee plans to perform an analysis to determine the cause. A similar event occurred in October 1989 as a result of the failure of a diode with the same part number (Section 4.1). Although, the licensee has been partially successful in reducing excessive operator and maintenance technician overtime rates during outages, the licensee's goals have not been fully achieved. The inspectors will continue to track the licensee's progress by an inspection followup item (Section 3.2.a).

One violation of NRC requirements was identified (Section 5.3). Subsequent to the trip caused by the dropped rod, a steam leak was identified on Steam Generator 2D. During the planning for repairs, the licensee determined, after questioning by the inspectors, that Technical Specification (TS) containment integrity requirements were not satisfied during a similar Unit 1 steam generator steam leak repair in October 1991. This violation occurred as a result of a lack of knowledge of TS containment integrity requirements by a broad range of licensee personnel, and is indicative of a weakness in the licensee's safety-awareness capabilities (Section 5.3).

The inspectors will continue to monitor the licensee's ability to resolve three long-standing safety-related system and component problems that are identified in this report. Two of the issues are emergency diesel generator (EDG) fuel subsystem leaks and dealloying of essential cooling water (ECW) system piping and flanges. These problems were identified during previous NRC inspections and additional examples were noted during this inspection period (Sections 5.4 and 6.1.a). A third issue identified during this inspection pertains to licensee actions to resolve cracking of ECW expansion joints which is being caused or exacerbated by ECW water hammer events. The resolution of this issue will be tracked by an inspection followup item (Section 6.1.a).

Performance in the areas of maintenance and surveillances was mixed. Many activities observed by the inspectors were well performed in the field. However, a number of weaknesses were identified, some of which have been discussed in previous NRC inspections. For example, the licensee has been unable to identify and correct the cause of recurring emergency diesel generator (EDG) trips when some EDGs are released from the emergency mode (Section 6.3). A second example of a discrepancy between the as-built configuration and the applicable vendor drawing was identified (Section 6.4). Problems with essential chiller reliability and maintenance were also noted. These and past problems are continuing to affect the reliability of the essential chillers. The practice of not performing an operability run prior to declaring an essential chiller operable was considered a weakness (Section 5.5). The adequacy of essential chiller maintenance procedures will be tracked by an unresolved item. (Section 5.5).

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

DETAILS

1. PERSONS CONTACTED

Houston Lighting & Power Company

*P. Appleby, Training Manager
*C. Ayala, Supervising Engineer, Licensing
*H. Bergendahl, Health Physics Manager
*M. Chakravorty, Executive Director, Nuclear Safety Review Board
*R. Dally, Engineering Specialist, Licensing
*D. Denver, Manager, Nuclear Engineering
*D. Hall, Group Vice President
*R. Hernandez, Manager, Design Engineer
*K. Jones, Senior Organizational Development Consultant
*T. Jordan, General Manager, Nuclear Assurance
*W. Kinsey, Vice President, Nuclear Generation
*J. Lovell, Technical Service Manager
*L. Manis, Jr., Management Analyst
*G. Midkiff, Manager, Plant Operations
*M. McBurnett, Manager, Integrated Planning and Scheduling
*A. McIntyre, Director, Plant Projects
*R. Rehkugler, Director, Quality Assurance
*S. Rosen, Vice President, Nuclear Engineering
*D. Sanchez, Director, Maintenance
*M. Wisenburg, Plant Manager
*W. Wood, Senior Staff Consultant

Central Power & Light

*B. McLaughlin, Owners' Representative

In addition to the above, the inspectors also held discussions with other licensee and contractor personnel during this inspection.

*Denotes those individuals attending the exit interview conducted on January 31, 1992.

2. PLANT STATUS (71707)

Unit 1 began the inspection period in Mode 1 (Power Operation) at 100 percent power and remained at full power through the end of the inspection period.

Unit 2 began the inspection period in Mode 1 at approximately 70 percent power, following the completion of the Unit 2 second refueling outage. On December 22, 1991, the unit reached 77 percent power. Later the same day, a power reduction was begun to allow for repairs on the main feedwater regulating valves. Unit 2 power was reduced to 12 percent the same day. On December 24, 1991, power was increased following repair of the main feedwater regulating valves. Unit 2 tripped at 30 percent power because of a failed open pressurizer spray valve (see NRC Special Inspection Report 50-498/91-35; 50-499/91-35). The unit was stabilized in Mode 3 (Hot Standby) following a reactor trip and safety injection actuation signal on low pressurizer pressure. Two days later, Unit 2 was brought critical and entered Mode 1 operation. Power was increased to 12 percent to place the main turbine generator on line. Problems were encountered with main turbine control and power was reduced to 3 percent (Mode 2). The next day, December 27, 1991, the main turbine throttle valves and control system were declared operable and power was increased to 12 percent to allow for functional testing of the main turbine. The main turbine generator was synchronized to the grid the next day and power was increased until Unit 2 reached 100 percent power on December 31, 1991.

Unit 2 remained at full power until January 22, 1992, when the unit tripped on power range neutron flux negative rate change as a result of a dropped control rod. The unit was stabilized in Mode 3 operation. The next day, Unit 2 was taken to Mode 4 (Hot Shutdown) to allow for rework on a steam leak that developed on a Steam Generator (SG) 2D inspection opening. Work on the SG steam leak had to be performed in Mode 5 (Cold Shutdown) and Unit 2 was taken to Mode 5 on January 24, 1992. Following repair of the steam leak, Unit 2 was taken critical (Mode 2) on January 27, 1992, and entered Mode 1 operation the same day. The main turbine generator was synchronized to the grid the next day. On January 30, 1992, 100 percent power was achieved. Unit 2 ended the inspection period at full power.

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) 50-498/91-013: Engineered Safety Features (ESF) Actuation Caused by Inadequate Troubleshooting Instructions

On April 12, 1991, Unit 1 was in Mode 3 operation. During troubleshooting of the Train B ESF sequencer, a Mode III (safety injection coincident with loss of offsite power) actuation signal was inadvertently initiated. The actuation signal occurred when leads that supplied power to optical isolator racks were lifted. The interruption of 24-volt power to the racks resulted in a processor recognition of a Mode III condition. Emergency Diesel Generator (EDG) 12 started as designed and the sequencer shed and reconnected the loads as designed. The cause of the event was determined to be inappropriate troubleshooting instructions because of an inadequate technical review prior to implementation.

Corrective actions taken included rewriting and successfully reperforming the troubleshooting instructions. Additionally, the troubleshooting program procedure was revised to reinforce the requirements for independent technical review of troubleshooting plans. Procedure OPGP03-ZM-0026, Revision 0, "Control of Troubleshooting," has since been revised to add requirements for a second technical review. A memorandum was issued to plant personnel to clarify and strengthen the requirements of second party verification of work instructions. The inspector considered these corrective actions acceptable. This LER is closed.

3.1.b (Closed) LER 50-499/90-014: Inadvertent Engineered Safety Features Actuation Due to Improper Use of Test Equipment

On September 26, 1990, Unit 2 was in Mode 1 at 100 percent power. During a monthly surveillance of the spent fuel pool radiation monitors, a containment ventilation isolation (CVI) actuation occurred because of a maintenance technician error. The test equipment in use was incorrectly connected to the circuitry using the current sensing function, which resulted in a low resistance path. The low resistance effectively shorted out a power supply and de-energized the actuation relays for the CVI. The CVI valves operated as designed. The cause of the event was failure of the technicians to verify that the test equipment was connected properly.

Corrective actions taken included developing a training module to emphasize the importance of attention to detail and self-verification. Training was provided to all applicable plant personnel. Additional corrective actions taken included disabling or modifying the current function on portable meters to minimize accidental use. The effectiveness of the Operational Improvement Program and Self Verification process will be continuously monitored by the NRC to determine the overall success of the programs. The inspectors determined that the immediate corrective actions taken were acceptable. This LER is closed.

3.1.c (Closed) LER 50-499/90-018: Unplanned ESF Actuation During the Performance of a Surveillance Test

On November 7, 1990, Unit 2 was in Mode 6 (Refueling). An ESF actuation of the Control Room, Reactor Containment Building, and Fuel Handling Building Heating, Ventilation, and Air Conditioning systems occurred during the performance of a Technical Specification (TS) required surveillance. An electrical transient resulted in a voltage fluctuation to the Train A powered radiation monitors. This voltage fluctuation caused the radiation monitors to actuate an ESF signal.

The specific cause of the electrical transient could not be identified; however, it was known to have occurred after the closure of an AC input breaker for Inverter 1201. The licensee attempted to recreate the event but was unsuccessful. Subsequent troubleshooting did not disclose any abnormalities. Although the cause of the event could not be clearly identified, it was suspected to be the result of voltage fluctuations following closure of the breaker. The licensee placed the equipment back in service and monitored the radiation monitoring system and associated power sources through existing programs. These programs included the issuance of service requests and requests for action (RFAs) in response to events, and periodic monitoring by use of surveillance tests. The licensee will investigate any similar events to determine the causes and appropriate corrective actions. This LER is closed.

3.1.d (Closed) LER 50-499/91-003: Reactor Trip Caused by Generator Protective Relay Actuation

On March 14, 1991, Unit 2 tripped from full power operation because of a generator lockout relay actuation (documented in NRC Inspection Report 50-498/91-08; 50-499/91-08). When the Unit 1 control room personnel closed Switchyard Breaker Y510 (energizes the Unit 1 main and auxiliary transformers), the Unit 2 generator isophase bus differential relay for B phase (87-1/G1) actuated. This resulted in a main generator lockout relay actuation. Actuation of Relay 87-1/G1 was caused by differences in the saturation rates of the two current transformers that supply the relay. Corrective actions were taken that included replacing Relay 87-1/G1; however, on March 30, 1991, a second Unit 2 trip from full power occurred because of the same problem. Following the second trip, in-depth testing was performed to locate and correct the cause of the problems. Further corrective actions taken are described in the discussion of LER 50-499/91-004 (see paragraph 3.1.e).

During the recovery process following the March 14, 1991, trip, a main steam isolation valve was manually reopened, which caused Steam Generator 2A level to decrease from 38 to 33 percent (low-low setpoint). An auxiliary feedwater (AFW) actuation signal was then generated because of the low-low level. The procedures used by the plant operators failed to provide guidance regarding low steam generator levels during main steam isolation valve manipulations. The applicable operating procedures were reviewed and revised to provide guidance on the potential for an auxiliary feedwater actuation while performing manipulations that may lower steam generator levels below the low-low setpoint. Additional corrective actions taken included issuing a training bulletin and incorporating the event into the licensed operator requalification training program. The inspector considered these actions to be appropriate. This LER is closed.

3.1.e (Closed) LER 50-499/91-004: Reactor Trip Caused by Generator Protective Relay Actuation

On March 30, 1991, Unit 2 tripped from full power because of a main generator lockout relay actuation. The lockout relay actuated because of an actuation of the Phase B generator Isophase Bus Differential Relay 87-1/G1. This trip was similar to the trip that occurred on March 14, 1991, which occurred following closure of Switchyard Breaker Y510. Previous troubleshooting for the cause of the first trip was unsuccessful. Temporary modifications were implemented in both units to remove the trip capability of the Relay 87-1/G1. Redundant protection is provided by the generator differential fault protection, main transformer differential fault protection, ground fault relays, and negative sequence relays.

The unit was again returned to power and functional tests were performed at 30-, 45-, and 100 percent reactor power levels. Test results indicated that the current transformers which provide inputs to Relay 87-1/G1 were saturating at different rates. This caused the relay to experience a differential current when subjected to transient currents, such as when closing Switchyard Breaker Y510. The neutral side current transformer (manufactured by

Westinghouse) is water cooled while the load side is air cooled (manufactured by General Electric). Since the cores were physically different, their saturation characteristics were different.

During a previous inspection, the inspectors considered the licensee's responsiveness in addressing the technical issues concerning the current transformers to be good (licensee actions are documented in NRC Inspection Report 50-498/91-11; 50-499/91-11). Long-term corrective actions planned include installation of an 11 ohm (estimated value) resistor in series with each phase of the neutral end of the Westinghouse current transformer. The resistors will be sized so as to cause the Westinghouse current transformer to have performance equal to that of the General Electric current transformer. This modification is scheduled to be implemented during the next refueling outage for each unit. At the end of this inspection period, the temporary modifications which removed the trip capability of Relay 87-1/G1 were still installed. This LER is closed.

3.2 Followup (92701)

3.2.a (Open) Open Item 498/9116-02; 499/9116-02: Operator Overtime

During an inspection in May 1991, an open item was identified concerning the amount of overtime utilized during outages by maintenance and operations personnel. The open item was documented to track licensee actions in response to the concern that overtime during outages appeared to be excessive and may have been a contributor to human performance problems. In response to this concern, the licensee established a goal that scheduled overtime during the recently completed Unit 2 outage would not exceed 50 percent. The inspectors reviewed the actual hours worked during that outage. This review indicated that control room opertors worked about 40 percent average overtime while nonlicensed operators worked about 50 percent. The maximum average monthly overtime worked by mechanical maintenance was 64 percent for the craft and 72 percent for foremen. During the nonoutage period of April through June 1991, maintenance personnel worked less than 7 percent overtime while control room operators averaged less than 15 percent overtime.

While the nonoutage overtime is well within accepted standards, outage overtime continues to exceed the established goals. Although the licensee initiated actions to address excessive overtime, these actions have not been fully developed and, as a result, complete fulfillment of the goal is not expected until the next refueling outage. Operations personnel hired for the accelerated and appentice nonlicensed operator classes in early 1991 had not yet become qualified and sufficiently experienced to allow them to independently perform tasks during the latest outage. The completion of Hot License Class-4 and receipt of NRC Operator Licenses occurred too late in the outage to provide any significant relief. The overtime for licensed operators is not expected to change significantly until a large group of Senior Reactor Operator upgrades become licensed next fall. At that time, shift and unit supervisor staffing may be sufficient to preclude the need for having shift and unit supervisors from other shift crews filling in for one another each time one of their peers is absent. There are currently 33 maintenance workers in a 3-year apprentice training program. Twelve entered the program the summer of 1991. These workers are expected to provide some relief in the upcoming outage.

Licensee management also plans to establish overtime limitations in a procedure revision. This revision will provide for a more uniform distribution of overtime and will establish a policy that precludes calling in operators on scheduled days off. The licensee's efforts to reduce the disruption in operator rest cycles and to provide for relief capability within the same crew are still in the formative stages. The results of these efforts will again be reviewed during the upcoming outage for Unit 1 in September 1992. As a result, this item remains open.

3.3 Followup on Corrective Actions for Violations and Deviations (92702)

3.3.a (Closed) Violation 498/9111-01; 499/9111-01: Failure to Properly Implement Locked Valve Program

During a routine inspection of the Unit 1 containment spray system, Valve 1-CS-0017A was found unlocked, contrary to procedural requirements. Additionally, 10 valves were found with their handwheels locked to other valves in conflict with procedural requirements. Corrective actions taken included: (1) counselling the nonlicensed operators involved in incorrectly locking Valve 1-CS-0017A, (2) revising the locked valve program procedure to remove unnecessary locking requirements, and (3) performing an overall review of the locked valve program implementation effectiveness. Components that had no regulatory or operational need to be locked were identified for removal from the program. The locked valve program procedure was revised after operating procedures and piping and instrument diagrams were reviewed to identify and resolve any discrepancies. The inspectors found these actions to be acceptable. This violation is closed.

4. ONSITE FOLLOWUP OF EVENTS AT OPERATING POWER REACTORS (93702)

4.1 Reactor Trip (Unit 2)

On January 22, 1992, at 9:10 a.m., Unit 2 tripped from 100 percent power. The reactor trip was generated by a power range high neutron flux negative rate trip signal. All equipment performed as expected, with the exception of: (1) pressurizer backup heater Group 2A failed to energize in the automatic mode on low pressurizer pressure, and (2) SG 2A bulk water sample Valve B2-SB-FV-4189A failed to shut on low-low SG level signal, but closed approximately 1/2 hour later. Since Unit 2 was in a regularly scheduled Train B outage when the trip occurred, EDG 22 was not in operation. As part of the recovery actions, Train B outage activities were curtailed to allow for the restoration of that train to service as quickly as possible.

The cause of the trip was determined to be a dropped control rod. The dropped rod caused the reactor protection system to actuate on a power range negative rate change, which resulted in a reactor and turbine trip. The rod dropped when a diode failed in the stationary gripper coil circuitry. Control rod drive mechanisms (CRDMs) are located in the dome of the reactor vessel. They are coupled to rod cluster control assemblies (RCCAs). The CRDMs function to insert and withdraw RCCAs within the core in order to control reactivity and to shut down the reactor. During normal plant operations, the CRDMs hold the RCCAs withdrawn from the core in a static position. In this mode, only one coil, the stationary gripper coil, is energized on each mechanism. If power to the stationary gripper coil is removed, the affected control rods (RCCAs) fall by gravity into the core. The reactor will then trip on either low pressurizer pressure or negative flux rate, depending on the time in core life and magnitude of the negative reactivity insertion. Diodes are installed in the electrical circuits supplying power to the stationary gripper coils. These diodes are isolation diodes that are used to prevent circulating current from traveling from one mechanism to another, subsequent to a reactor trip.

The cause of the dropped control rod was due to the failure of a diode. The cause of the diode failure was not immediately known but was suspected to be a result of elevated temperature of the diode. Thermographic analysis of the failed diode disclosed a slightly elevated temperature of 44° Centigrade (C) while the normal range of all diodes was 33.5°C. Vendor information indicated that the temperature limit for acceptable diode operation is approximately 54°C at a rated current of 12 amps. The defective diode was subsequently replaced (see Section 6.4).

After the reactor trip, the licensee initiated troubleshooting to determine the cause of the Group A pressurizer heaters not energizing in automatic. Several hours after the reactor trip, operations personnel functionally tested the pressurizer heaters. When the pressurizer master controller output was purposely decreased, the Group 2A heaters energized in automatic as designed. A work request was issued to electrically troubleshoot the circuitry; however, the cause of the problem was not clearly identified. Following functional testing with satisfactory results, the pressurizer heaters were declared operable on January 24, 1992.

The containment penetration associated with the SG 2A bulk water sample line isolation valve was isolated by closing the outboard valve and removing power to it. Further discussion of Valve FV-4189A is provided in Section 7.1.

Following plant shutdown, a steam leak was identified on a 2-inch inspection opening on SG 2D. A plant shutdown to Mode 5 was required in order to repair the leak. Further discussion of the steam leak repair is provided in Section 5.3.

This event was the second time that Unit 2 has tripped because of a dropped control rod. On October 13, 1989, Unit 2 tripped from full power because of a power range high neutron flux negative rate trip signal. The cause of the event was believed to be an intermittent high resistance connection on a stationary gripper diode in the rod control system. The inspectors have learned that on October 11, 1989, Vogtle Electric Generating Plant - Unit 2, was in Mode 1 at 58 percent power when the reactor tripped on high negative flux rate. Investigation revealed that a diode in the control rod power supply circuitry had failed, resulting in the loss of power to stationary gripper coil. The subsequent drop of a control rod into the core initiated the negative flux rate trip. The failed diode was manufactured by Westinghouse and has Part

No. 1N1206AR. The faulty diodes in the October 1989 STP Unit 2 event and the most recent event were also Westinghouse Part No. 1N1206AR. The licensee plans to perform postfailure analysis on the failed diode, with some vendor assistance, to determine the root cause of the failure. The licensee's investigation and corrective actions will be addressed during review of the LER which will be issued for this event.

5. 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 control room staffing, operator decorum, shift turnover, adherence to TS, and that overall personnel performance within the control room was 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.

5.1 Main Feedwater Regulating Valve Problems (Unit 2)

During Unit 2 startup, following the second refueling outage, problems were encountered with the main feedwater regulating valves. Unit power was reduced from 77 percent to 12 percent on December 22, 1991, to allow for work on the valves. Train A Valve N2-FW-FCV-0551 had unexpectedly gone full open when the valve was placed in automatic. The cause of the problem was determined to be sticking mercury wetted relay contacts on a circuit board. The contacts were unstuck, the circuit board was replaced, and the valve then operated correctly. Train B Valve N2-FW-FCV-0552 was oscillating in both manual and automatic and was affecting feedwater flow rates. Circuit boards in the control circuit were swapped out with those of the Train C valve; however, this had no effect. The cause of the oscillations was subsequently determined to be a defective positioner on the valve. The positioner was replaced. All four feedwater regulating valves were returned to service and operated correctly. As of the end of the inspection period, the licensee was still investigating the cause of the sticking relay contacts.

5.2 Main Turbine Stop (Throttle) Valve Problems (Unit 2)

On December 26, 1991, Unit 2 was in the process of starting up following a trip that occurred 2 days earlier. Several hours after entering Mode 1 (Power Operation), the plant operators attempted to roll the main turbine by admitting steam. Problems were encountered with the electrohydraulic control (EHC) of the main turbine. Besides experiencing turbine control problems, the throttle valves failed to close immediately upon demand following a manual turbine trip signal. Only one throttle valve (TV), TV-3, closed quickly. The other three TVs took approximately 1 minute to close. Power was reduced from 12 percent (Mode 1) to 3 percent (Mode 2 - Startup) to allow for work on the TVs and EHC control system.

A service request was issued to initiate troubleshooting of the EHC problems on the main turbine. Although the cause of the problems was not clearly identified, corrective actions that were taken included replacing an analog switch board and calibrating an EHC pressure switch (main turbine automatic stop trip fluid pressure). With a vendor representative present, the EHC system was monitored at various points during turbine startup and TV-to-governor valve transfer. No problems were observed and chart recorder traces failed to identify any abnormalities. The TVs were declared operable the next day. The main turbine generator was synchronized to the grid on December 28, 1991.

On January 28, 1992, Unit 2 was in Mode 1 at 11 percent power. During the main turbine generator startup process, the turbine was tripped while engineers were present to monitor the TVs. Valves TV-1 and TV-2 took longer than required to go full closed. The shift supervisor declared the two valves out of service and a station problem report was generated. The licensee determined that the cause of TV-1 and TV-2 failing to close quickly was thermal binding of the valve actuator linkage.

In October 1987, a letter was sent to the licensee from Westinghouse (Customer Advisory Letter 87-03). The letter documented previous incidents of TVs sticking open because of the large number of tight clearances which could cause mechanical binding during thermal transients. Thermal binding can occur shortly after the TVs are full open; however, the thermal binding problem dissipates after a few minutes.

The original Westinghouse letter was incorporated into the licensee's procedures. However, after the January 28, 1992, event, additional procedure revisions were made to incorporate lessons learned into the startup process. The procedure now requires that during turbine speed increases, turbine speed be stabilized prior to performing a TV-to-governor valve transfer. This change was incorporated to minimize potential EHC system fluctuations. A second change was made to add additional valve testing instructions (verify valve will start to go shut) to the plant startup procedure. The Unit 2 main turbine was subsequently returned to service without any additional TV sticking problems observed.

5.3 SG Steam Leak (Unit 2)

During the recovery of Unit 2 from the reactor trip that occurred on January 22, 1992, a steam leak was found on SG 2D. The licensee suspected that a 2-inch hand hole cover on the secondary shell side of SG 2D was leaking about 1 gallon per minute (gpm). Unit 2 was taken to Mode 5 to allow for repairs to be performed. SG 2D was drained on January 24, 1992, and maintenance personnel removed the cover and performed an inspection, but could not find the cause of the leak. The leakage was subsequently determined to be coming from an 8.75-inch cover located above the 2-inch cover. The licensee originally thought the 2-inch hand hole cover was leaking because of the way the 8.75-inch cover leak was impinging on the 2-inch hand hole cover. Installed insulation masked the true source of the leak.

Service Request SG-160104 was issued to repair the leak on the 8.75-inch cover. This access is used for sludge lancing and was accessed during the recent refueling outage. The gasket was found to be unevenly compressed on the 8.75 inch hole. The torquing instructions were revised to ensure a gap measurement was obtained during each torquing pass. Previously, this activity was considered to be within the scope of the skill of the craft. Both covers were retorqued and postmaintenance testing did not identify any additional leakage.

During the planning of the repair of the SG 2D steam leak, the licensee determined that the work could not be performed in Mode 4 as originally planned. Section 6.2.6.1 of the Final Safety Analysis Report states that the SG shell is considered an extension of the containment boundary. Opening the SG access ports during Modes 1-4 is considered a violation of TS 3.6.1.1, "Containment Integrity," because it cannot be verified that maximum containment leakage rates required to satisfy containment integrity would not be exceeded. As a result of inspector questioning, a licensee review of previous events disclosed that, at 3:30 a.m. on October 18, 1991, an SG 1C hand hole cover was removed while Unit 1 was in Mode 4 operation. The cover was reinstalled approximately 48 hours later at 4 a.m. on October 20, 1991. Operating in Mode 4 for approximately 48 hours with the SG 1C hand hole cover removed is considered a violation of TS 3.6.1.1 (498/9134-01). This violation appears to have occurred because of a lack of understanding of TS containment integrity requirements by a broad range of licensee personnel.

5.4 EDG Nozzle Holder Crack (Unit 2)

On January 29, 1992, EDG 23 was started for a routine surveillance run. About 45 minutes into the 1-hour run, a fuel leak was observed and the engine was shut down. The fuel oil leak occurred on Cylinder 8R at the nozzle holder on the fuel injector nozzle assembly. The system engineer was present and observed no spraying of fuel oil onto the exhaust header or turbocharger (sources of ignition). The nozzle assembly was removed and a longitudinal crack was visually observed in the nozzle holder. The nozzle holder was replaced, the engine was successfully tested, and EDG 23 was returned to service the same day.

Plant operators initially classified the event as a nonvalid failure; however, plant engineering subsequently reclassified the event as a "no test." When the fuel oil spray is not on the exhaust header or turbocharger (a condition that could result in fire induced damage to the EDG), the classification is a "no test" when the EDG is intentionally secured before it is operated for 1 hour or more at 50 percent or more of continuous rating. The event was not a valid failure because the fuel oil spray was not impinging onto the exhaust header or turbocharger which would represent an imminent fire hazard.

The loss of fuel oil has been previously ´ ressed in a licensee justification for continued operation (JCO). The basis for the JCO is that the associated jerk pump can be racked out (operator intervention) before the available fuel margin is expended. The JCO also verified that this action can be performed on two cylinders and the engine will continue to function as designed. Long-term corrective actions are planned and include replacement of all nozzle holders, delivery valve holders, and high pressure lines with upgraded parts. The work is planned for completion by the end of the next refueling outage for each unit. Additionally, a project manager has been assigned the task of overseeing all activities, including upgrades, of the EDGs. The position is a temporary, but full time, managerial assignment. This issue and other EDG reliability problems will be discussed during a licensee and NRC management meeting that is scheduled to be held on March 13, 1992.

5.5 Essential Chiller Problems (Unit 1)

The essential chilled water system is designed to provide chilled water to selected air handling units under any normal or emergency condition. The system consists of three 50 percent capacity trains. There are two water chillers in each train. Each water chiller is a centrifugal type with a water cooled condenser and is provided with necessary accessories for automatic operation.

On January 14, 1992, Essential Chillers 11B and 12B (Unit 1, Train B chillers) were removed from service for routine preventive maintenance. Part of the work involved performing calibration checks on the chiller's evaporator differential pressure switches. The switches are designed to trip the chiller on low evaporator water (chilled water) flow and energize a "No Flow" light on the local control panel. Switch B1-CH-PDSL-9483, located on Chiller 11B, was found to be defective and was replaced. Switch B1-CH-PDSL-9508, located on Chiller 12B, was recalibrated. On January 16, plant operators attempted to start the chillers, but the chillers would not start. Service requests were written to troubleshoot the chillers. In addition to not starting, the local "Low Flow" alarm would not clear with the chilled water pump running.

The two chillers had to be back in service within 72 hours or a plant shutdown was required in accordance with the TS. Operability requirements for chillers are delineated in TS 3.7.14. After the chillers had been out of service for about 60 hours, the licensee became concerned the chillers might not be fixed within the required time frame. A request for a Temporary Waiver of Compliance from the provisions of TS 3.7.14 was submitted to the NRC. The licensee requested an extension from 72 hours to 10 days to restore the B train chillers to service. The justification for the extension was based on the STP Probabilistic Safety Assessment, and because the other two 50 percent capacity trains were still operable. The chillers were returned to service after about 68 hours, 4 hours less than the original 72-hour time limit; therefore, the waiver was not needed.

The essential chiller chilled water flow switches have a history of drifting out of calibration. This problem generates false chilled water low flow signals which have inhibited chiller starts. The cause of the flow switch calibration drift was not clear but was suspected to be due to either switch design or the method of valving in the switch. These flow switches are differential pressure switches that have no equalizing valve. When the switch is valved in with the system running, the switch can be overranged and thrown out of calibration. Overranging also may be occurring during switch venting. The switch is rated at 20 psid and, with line pressure over 100 pounds per square inch gage (psig), improper venting or alignment can damage the switch. A station problem report was written to investigate the problem with the chiller differential pressure flow switches. Improvements are needed in the method of switch calibration and the instrument valving process. The adequacy of essential chiller maintenance procedures is unresolved pending futher inspection followup (498;499/9134-02). Additionally, long-term corrective actions, such as modifying the switch design, may be necessary. The inspectors noted that there has been a relatively large amount of corrective maintenance associated with the essential chillers.

On January 21, 1992, at 12:32 p.m., Essential Chiller 11C failed to start. Differential Pressure Switch C1-CH-PDSL-9493 was found to be sticking and was replaced. While Essential Chiller 11C was out of service, Essential Chiller 11B was discovered to have no visible level in the upper oil reservoir sight glass. This has occurred repeatedly over the life of the plant. Plant operators declared Chiller 11B out of service at 2:08 a.m. on January 22, 1992. With Chiller 11C (Train C) out of service at the same time as Chiller 11B (Train B), entry into TS 3.0.3 was required. TS 3.0.3 requires initiation of a plant shutdown within 1 hour. An oil reclamation process was begun to restore oil in the reservoir. This process involves transferring oil from the lower reservoir to the upper reservoir using the auxiliary oil transfer pump. The correct oil level was verified in the upper sight glass following oil reclamation and Chiller 11B was declared operable at 2:45 a.m. the same day. However, the inspector noted that this chiller was not started to verify operability prior to declaring it operable. Chiller start following an oil reclamation process was not required by procedure. The inspectors considered this to be a weakness. The licensee stated that corrective actions would be taken to ensure that the chiller would be started following future maintenance activities. The second chiller, 11C, was returned to service on January 22, 1992, at 7:27 a.m.

Entry into TS 3.0.3 is reportable to the NRC. The licensee will submit an LER to the NRC within 30 days describing the event in detail, including corrective actions planned.

5.6 Engineering Group Reorganization

The licensee's Plant Engineering Department (PED) was recently reorganized to provide better management of daily engineering activities. The Nuclear Engineering Department was created apart from PED. This separate group is now responsible for Nuclear Fuel, Plant Analysis, Reactor Engineering, and Thermal Hydraulics. PED continues to be responsible for Plant Computers, Plant Systems, and Programs. PED also assumed responsibility for the Preventive Maintenance Program on November 25, 1991. This change in program responsibility strengthens the role of the system engineers in the development and review process for preventive maintenance tasks.

5.7 Over Temperature/Delta Temperature (OT delta T) Setpoint

In 1986, Westinghouse identified a concern relative to drift in the calibration of Veritrak/Tobar transmitters. Westinghouse had reported that, during adverse temperature conditions, the output of the transmitters would drift beyond the assumptions used to develop the STP reactor trip and ESF setpoints. The notification identified the setpoints of concern. The only setpoint identified at that time requiring action was the pressurizer pressure low safety injection setpoint. The recommendation was to raise that setpoint to 1869 psig. In 1988, Westinghouse issued a final report on this issue. In that final report, they provided a series of recommended setpoints for all of the setpoints impacted by the Veritrak/Tobar issue. The licensee issued a report to the NRC under 10 CFR Part 50.55(e), wherein, a setpoint of 1869 psig was established for pressurizer pressure low safety injection. That report concluded that, with that setpoint change, all other setpoints were conservative to the safety analysis.

During a recent assessment of the adequacy of instrumentation setpoints, which was conducted by the licensee's Engineering Assurance Group, Veritrak transmitters were selected by Engineering Assurance for review. This assessment was conducted as a result of problems noted at another plant. In the course of addressing the issues raised in 1988, discussions were held with Westinghouse personnel to better understand discussions. It was determined that the TS setpoint for OT delta T was not conservative to the safety analysis, as believed in 1988. Additional errors in the T-hot Temperature Averaging System algorithm were identified which were not taken into consideration. This caused the present TS value of 1.08 for K-1 (used in determining the OT delta T setpoint) to not be conservative to the safety analysis.

OT delta T is a continuously calculated reactor trip that provides core protection to prevent departure from nucleate boiling for all combinations of pressure, power, coolant temperature, and axial power distribution. The OT delta T trip setpoint is established by a formula contained in Table 2.2-1 of the TS. The formula includes a constant, K-1, which is equal to 108 percent power and also includes corrections. These corrections take into account changes in density and heat capacity of the reactor coolant. Other corrections include: dynamic compensation for piping delays, compensation for abnormal axial power distribution and changes in subcooling or the pressure-temperature relationship. The K-1 constant, also known as the OT delta T constant, is derived by analysis and includes consideration of statistical errors and instrument accuracy.

A change in the accuracy of a temperature compensation as a result of the loss of one RTD in a leg of the reactor coolant system results in an additional statistical error which changes the original value of K-1. This occurs when thermal drift of a transmitter results during an adverse containment event and is not properly considered.

A JCO was prepared and approved to allow the units to operate at the current TS limit by removing the source of the error. The error is only applicable if one of the three RTDs for a given channel is inoperable. By taking the compensatory action of placing a channel in trip if it has a bad RTD, the error does not have to be accounted for, and the current TS limit of 1.08 is within the safety analysis. Region IV and Office of Nuclear Reactor Regulation personnel reviewed the JCO and found it to be conservative. The licensee is continuing to evaluate what changes need to be made to the safety analysis and the TS in order to preserve the present operating margins and eliminate the need for the JCO.

Conclusion

Equipment problems in Unit 2 resulted in two unit trips and several delays in startup and operation. A loose feedback arm on the pressurizer spray valve caused one reactor trip while a failed diode in the rod control system resulted in the second trip. Delays in unit startup were caused by problems with the main feedwater regulating valves, main turbine throttle valves, and the electrohydraulic control system for the main turbine. These problems were indicative of the need for improved Unit 2 material condition.

Several essential chiller problems were identified during this inspection period. A review of the essential chiller material history revealed that there were numerous corrective maintenance activities associated with the essential chiller. Collectively, these problems were indicative of potential design problems and weak maintenance procedures. The adequacy of essential chiller maintenance procedures is unresolved pending further inspection followup.

A violation of TS 3.6.1.1 was identified. Containment integrity was breached on October 18, 1991, when a SG hand hole cover was removed while Unit 1 was in Mode 4 operation. This event was attributed to licensee personnel not taking into account that the SG shell is an extension of the containment boundary.

A continuing problem with EDG fuel oil leaks was again experienced. A cracked delivery valve holder resulted in removing EDG 23 from service. This continuing problem has not been resolved; however, the licensee has finalized plans to replace the current design with a new design.

6. 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.

6.1.a Repair of a Cracked Pipe and Expansion Joint (Units 1 and 2)

The ECW system is designed to supply cooling water to various safety-related systems for normal plant operation, shutdown, and during and after a postulated design basis accident. The ECW system is constructed of aluminum-bronze, which is a highly corrosion resistant alloy of copper. The ECW system has been historically affected by leaks as a result of through-wall cracks in certain ECW pipe welds and expansion joint bellows and by dealloying of large bore flanges and fittings.

Leaks were discovered in both the inlet and outlet piping to the EDG intercoolers. The leaks were the result of cracks in the expansion joint bellows. The failures were discovered during the startup and routine surveillance testing of the EDGs. The apparent causes of the expansion joint leaks included: (1) the ECW system was being affected by a water hammer problem when the ECW pumps were secured, (2) the initial alignment of the expansion joints was not correct or the water hammer effect has altered the alignment, and (3) the type of expansion joints used may have been inadequate for the application.

The effects of water hammer were observed during a test performed in August 1990. Following the test, a leaking expansion joint was removed for analysis. The analysis concluded the leak was caused by fatigue cracking in the bellows. Short-term corrective actions taken included revising the ECW operating procedures to reduce the effect of water hammer on the expansion joints. The ECW supply valves to the EDG were required to be shut prior to a pump trip in order to minimize the water hammer effect. Although the inspector considered this short-term action to be a symptomatic repair, the licensee initiated a calculation which demonstrated that only the ECW lines serving the EDG were affected by the slightly excessive pressure surges occurring when an ECW pump was tripped. No other portions of the ECW system have been affected by the water hammer events. Additional instances of leaking expansion joint bellows have developed. This has resulted in the following corrective actions: replacing the expansion joints with identical ones, replacing the expansion joints with temporary flanged pipe spool pieces, and monitoring selected leaking bellows to ensure leakage remained below a preset limit.

Long-term corrective actions planned include replacing all expansion bellows at the EDG intercoolers with hard pipe spools, performing pipe stress analyses to determine the need for additional pipe supports, and adding vacuum breaker valves to reduce water hammer pressures. Vacuum breakers were installed in the Unit 2 ECW to EDG piping during the last refueling outage. One permanent flanged pipe spool was installed on the Unit 2 Train C ECW to EDG intercooler inlet piping. The remaining five pipe spools are scheduled for installation during the next Unit 2 refueling outage. The vacuum breakers have not been installed in Unit 1. One Unit 1 pipe spool out of six has been installed to date. The remainder of the modifications are also scheduled to be installed during the next Unit 1 refueling outage. Licensee corrective actions associated with the resolution of ECW water hammer events will be tracked by an inspection followup item (498/9134-02; 499/9134-02).

Through-wall cracks have been found in welds in the aluminum bronze piping. Data from failure analyses indicated that a pre-existing flaw contributed to the development of the cracks. Poor backing ring fit-up is also suspected as having contributed to crack development. Crack growth occurs by a process of propagation of the crack tip after dealloying (a form of corrosion). This process, although slow, results in preferential through-wall propagation rather than an increase in crack length. Leakage, therefore, occurs long before any significant growth occurs in the crack length. The above ground large bore welds are currently monitored for leakage by monthly walkdowns. The piping below the ground is monitored by a walkdown of the ground condition above the pipe. Soil changes have not been detected that would suggest that a leak exists in the buried piping. A JCO was developed to allow for plant operation with through-wall cracks in ECW pipe welds. Calculations generated to support the

JCO indicated that a leakage rate of 1000 gpm per train can be tolerated without impacting the ability of the ECW system to perform its safety function. To date, six through-wall cracks have been found in ECW welds and two have been reworked.

Leaks have also developed because of dealloying of large bore pipe flanges and fittings. The system flanges, fittings, valves, and pumps are constructed of aluminum-bronze castings, Grades CA 952 and CA 954. Castings of these grades will dealloy in the presence of crevices. This phenomena was reported to the NRC at the time of the request for the Unit 2 operating license. At that time, castings in the small bore portion of the ECW system were leaking at several locations. Small bore castings were replaced in Unit 2 prior to operation and in Unit 1 prior to and during the first refueling outage. On the basis of examinations, it was anticipated that large bore components were unlikely to have through-wall leakage at any location in the short term.

Following further review, the licensee determined that flanges could show through-wall leakage because of dealloying in the foreseeable future and a JCO was issued to document this. Other cast components such as valves and pumps typically do not have a backing ring type of crevice and have greater thickness and were, therefore, not expected to dealloy rapidly. There are about 45 cast fittings with backing rings in each unit that were deemed likely to dealloy, resulting in a through-wall crack. The licensee planned to replace them as they were identified as leaking. The catalyst for crack development was the existence of flaws generated in the manufacturing process. Eleven occurrences of dealloying of castings (conservatively called a crack) have been discovered to date. In accordance with the JCO, the leaking components have to be replaced or other corrective actions taken, within 100 days, to assure no gross failures will occur.

During a walkdown on January 7, 1992, two dealloying flange cracks were found on the 6-inch diameter inlet and outlet connections to Essential Chiller 21B (Unit 2, Train B). One crack was found on the inlet line (EW-2208) and the other on the outlet line (EW-2209). RFAs were written to request engineering assistance and evaluation. Repairs will be made when time permits. Interim corrective actions include performing routine visual inspections to monitor crack growth.

During this inspection period, an expansion joint pin hole leak and a flange crack were repaired on the EDG 11 intercooler inlet line. A crack in the flange fitting was identified by quality control inspectors during a walkdown in August 1991. The crack was found in the flange fitting above weld FS-4350 on a 6-inch line. An RFA was written to evaluate the operability of the train and to list the required repairs. A Conditional Release Authorization was issued that allowed continued operation of ECW Train 1A. The expansion joint located adjacent to the cracked flange, that was identified in May 1990 as having a pin hole leak, was also successfully repaired.

The work was performed under Service Request EW-151258 and consisted of: (1) removing the expansion joint, (2) cutting the cracked flange off the pipe spool for further crack analysis, (3) fabricating a new spool assembly,

(4) welding the new flange/spool piece assembly in place, and (5) performing a hydrostatic test. Nondestructive testing of each weld pass and a final penetrant test were also performed. The NRC inspectors observed this work activity over a period of several days.

In addition to the other short-term corrective actions, the licensee assigned a department manager to the position of Project Manager. This person was provided with the responsibility to oversee all activities associated with the ECW system. Licensee long-term actions to resolve ECW dealloying will be discussed during a management meeting that is scheduled to be conducted on March 13, 1992.

6.2 Rework of Containment Hydrogen Analyzer (Unit 1)

Two independent, redundant systems for containment hydrogen monitoring are provided in each unit. A routine operability test was performed on Analyzer A1-CM-AIT-4102 on January 6, 1992. The test was performed using Surveillance Procedure OPSP02-CM-4102, Revision 0, "Containment Hydrogen Analyzer Analog Channel Operational Test (ACOT)." The output signal of each analyzer is indicated at the locally mounted analyzer and is indicated, recorded, and alarmed in the main control room. During the test, the local indicator pegged low while the analyzer was in operation.

Service Request CM-135680 was issued to troubleshoot the analyzer. The technicians noticed that whenever the front panel was lowered to access the internals, the transmitter output would change. The two wires leading to the signal converter were determined to be damaged and required replacement. These wires are routinely lifted and relanded during performance of the monthly ACOT. The cause of the crimped wires was not clearly identified by the licensee, but it was suspected that they were crimped during a previous closure of the panel door.

The original wiring used (Boston Insulated wire) was discovered to be obsolete and an alternate brand of wire (Rockbestos) was re-installed. A Document Change Notice was written and a 10 CFR Part 50.59 review was performed to justify the change in wire manufacturer. The wires were replaced and the analyzer was subsequently returned to service on January 10, 1992.

6.3 Troubleshooting of Emergency Diesel Generator (Unit 2)

EDG 21 was started in the emergency mode on December 7, 1991, in order to verify operability in accordance with TS 3.8.1.1 requirements. When the engine was released from the emergency mode, EDG 21 tripped for no apparent reason. EDG 21 was restarted a second time in the emergency mode, was released from emergency mode, and did not trip. An operability surveillance test (1-hour run) was performed and EDG 21 was declared operable. The event was classified as a nonvalid failure. The cause of the EDG 21 trip was not determined. EDG 21 was again started December 15 and 19, 1991, and operated satisfactorily. A special report was submitted and the licensee committed to troubleshoot the EDG during the next regularly scheduled train outage.

On December 24, 1991, Unit 2 experienced a reactor trip and safety injection signal because of low pressurizer pressure. All three EDGs automatically started as designed. In accordance with procedural requirements, the EDGs were released from the emergency mode after the verification of availability of offsite power. EDG 21 tripped when released from the emergency mode. There were no alarms or indications available that identified the cause of the trip. This event was declared a nonvalid failure of EDG 21.

On January 15, 1992, troubleshooting of EDG 21 was performed in accordance with Service Request DG-101051. A recorder was installed to locally monitor the trip circuit loop voltages. No fluctuations were recorded during an EDG test run. The cause of the two nonvalid failures could not be clearly identified. The licensee plans to perform additional troubleshooting during future EDG outages. The licensee committed to send a supplementary report to the NRC identifying the causes and corrective actions taken by April 30, 1992. Although this problem does not affect the operation of the EDG in the emergency mode, the inspectors noted that this problem has been recurring for the past several months, and licensee efforts, to date, have been unsuccessful in identifying the cause of the condition and correcting it.

6.4 Troubleshooting and Repair of Rod Control System (Unit 2)

On January 22, 1992, Unit 2 tripped from full power because of a dropped rod. Subsequent troubleshooting of the rod control system identified a defective diode associated with the dropped rod. The diode was replaced. Two other diodes were also replaced as a precaution because one was identified as having an elevated temperature and one was found to have a suspect solder joint.

A complete visual inspection of each diode was also performed. As a precaution, all diodes having the same lot number as the failed diode were replaced. A total of 37 diodes were replaced. After diode replacement, postmaintenance testing performed included thermography checks. All results were satisfactory.

During the removal of the first diode, the inspector noticed that the technicians initially experienced trouble in removing the defective diode. The technicians discovered that a lock nut and washer were installed on the back side of the heat sink of which the diode is attached. The work instructions, which came directly from the vendor manual, provided direction to "carefully remove the diode from the heat sink." No description of a lock nut or washer was provided in the work instructions. The technicians had to remove the heat sink from its mounting bolts in order to remove the diode. Further review by the inspector revealed that the vendor manual and associated vendor drawings of the diode and heat sink did not describe or depict the lock nut and washer. Not having these components listed on the vendor documents is considered a weakness in the documentation of the as-built plant configuration. A similar observation was identified in NRC Inspection Report 50-498/91-35; 50-499/91-35. That report documented the events surrounding the December 24, 1991, Unit 2 reactor trip. One of the causes of the trip was a missing lock nut on a valve positioner feedback arm for a pressurizer spray valve. The missing nut allowed the feedback arm to become disconnected, which caused the pressurizer spray valve to fail open and cause a reactor trip on low reactor coolant system pressure. The associated vendor drawing for the valve positioner was identified as not correctly representing the as-built configuration.

Conclusion

Rework of two ECW leaks was performed during this inspection period. However, numerous leaks still exist that also require repair. Damaged wires were found on the containment hydrogen analyzer and were replaced. The engineering evaluation of the ECW leaks and damaged hydrogen analyzer wires was very good, as indicated by the completeness of the JCOs, RFAs, conditional releases, and 10 CFR Part 50.59 reviews performed. Long-term actions associated with ECW water hammer events will be tracked by an inspection followup item. Troubleshooting of two EDG 21 nonvalid failures did not identify the cause EDG trips. The troubleshooting performed was appropriate for the circumst ... , however, additional troubleshooting is required by the licensee in order to identify and correct the cause of the trips. A deficient vendor supplied drawing was identified during an inspection of the rod control system troubleshooting and repair. A similar observation was noted during a previous NRC inspection. Although problems with vendor supplied drawings still exist, the licensee has taken action to improve the overall quality of plant drawings.

7. BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

Selected activities were observed to ascertain whether the surveillances of plant systems and components were being conducted in accordance with TS and other requirements. The inspection included a review of the procedures being used, assuring that the test equipment was correct for the task being performed and verifying that data measured was within acceptance criteria limits. All comments and observations were reported to the licensee for resolution.

7.1 SG Blowdown System Valve Operability Test

On January 22, 1992, Unit 2 tripped from full power. During plant recovery, SG bulk water isolation Valve B2-SB-FV-4189A failed to go full closed when an SG water level Low-Low signal was generated. The valve did go full closed between 30-50 minutes after the trip without operator action. Valve B2-SB-FV-4189A is a 1-inch, solenoid operated, globe valve, which is manufactured by Target Rock. The valve is designed to go full closed within 5 seconds after an auxiliary feedwater initiation signal (SG Low-Low level). A second solenoid operated valve, A2-SB-FV-4189, is located immediately adjacent to and upstream of A2-SB-FV-4189. The valves are located in a line that is associated with the secondary side of the SGs. Both valves are located on the outside of the reactor containment and are SG isolation valves.

During the January 22, 1992 event, A2-SB-FV-4189A did close immediately upon demand. The slow closure of Target Rock solenoid valves is known to occur under conditions where little or no differential pressure exists across the valve. Since B2-SB-FV-4189A is downstream of A2-SB-FV-4189, a closure of A2-SB-FV-4189 prior to full closure of B2-SB-FV-4189A will remove the differential pressure across A2-SB-FV-4189A.

On January 24, 1992, B2-SB-FV-4189A operated as designed when SG 2D was drained for maintenance (low-low water level isolation signal generated). Troubleshooting was then performed and Valve B2-SB-FV-4189A operated properly each time it was stroked. The reason the valve did not fully shut on January 22, 1992, was not clearly identified; however, the lack of differential pressure across the valve was considered to be the most likely cause. This conclusion was discussed at a Plant Operations Review Committee meeting on January 24, 1992.

On January 28, 1992, a postmaintenance test of B2-SB-FV-4189A was performed in accordance with Surveillance Procedure 2PSP03-SB-0001, Revision 1, "Steam Generator Blowdown System Valve Operability Test." The inspector observed the surveillance. The valve closed within the required procedure acceptance criteria time interval of 2 seconds. During the test, B2-SB-FV-4189A closed in 0.98 seconds with redundant A2-SB-FV-4189 shut. The valve was subsequently returned to service.

7.2 Surveillance of Seismic Monitoring System Accelerograph

Surveillance Procedure 1PSP05-SY-0010, Revision 1, "Reactor Containment Building Self-Contained Seismic Channel Calibration," is an 18-month surveillance that is required by TS 4.3.3.3.1. The surveillance was performed on January 30, 1992, and was observed by the inspector. No problems were identified.

7.3 Independent Walkdown of Valve Checklist

An independent walkdown of Surveillance Procedure 2PSP03-CC-0011, Revision 2, "Component Cooling Water Valve Checklist," was performed to verify that all valves were correctly aligned. The surveillance is performed at least once every 31 days to comply with TS 4.7.3.a and 4.7.3.c. All valves were found in the position necessary to support plant operation. Minor items, such as a leaking transmitter connection, a stuck local indicator (nonsafety-related), and a typographical error in the procedure, were reported to plant operations personnel and have since been corrected.

Conclusion

Valve B2-SB-FV-4189A failed to fully shut upon demand following the Unit 2 trip; however, a redundant component did perform its function to isolate the sample line. Troubleshooting activities did not clearly identify the problem. The valve was observed to work properly and was returned to service. A seismic monitor surveillance was performed in accordance with procedural requirements by knowledgeable personnel. A walkdown of a valve checklist did not identify any significant concerns and the system was found in the correct alignment.

8. EXIT INTERVIEW

The inspector met with licensee representatives (denoted in paragraph 1) on January 31, 1992. The inspector summarized the scope and proposed findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

LIST OF ACRONYMS AND INITIALISMS

ACOT	analog channel operational test
AFW	auxiliary feedwater
C	Centrigrade
CRDM	control rod drive mechanism
CVI	containment ventilation isolation
ECW	essential cooling water
EDG	emergency diesel generator
EHC	electrohydraulic control
ESF	engineered safety features
gpm	gallons per minutes
JCO	justification for continued operation
LER	licensee event report
MSIV	main steam isolation valve
PED	Plant Engineering Department
psid	pounds per square inch differential
OT delta T	over temperature delta temperature
psig	pounds per square inch gage
RCCA	rod cluster control assembly
RFA	request for action
RTD	resistance temperature detector
SG	steam generator
STP	South Texas Project Electric Generating Station
TV	throttle valve
TS	Technical Specification