ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/95-29
50-499/95-29

Operating License: NPF-76
NPF-80

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: November 19 through December 30, 1995

Inspectors: D. P. Loveless, Senior Resident Inspector
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Approved: Ronald A Kramer for. — 1-22-96
J. L. Pellet, Acting Chief, Project Branch A — Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events, operational safety verification, maintenance and surveillance observations, plant support activities review, evaluation of onsite engineering, and followup on open operations, maintenance, and engineering items.

Results:

Plant Operations

- The Unit 1 reactor tripped as a result of an offsite grid disturbance and the improper substation maintenance of a switchyard relay (Section 2.2).

- An unresolved item was established to track and evaluate the conduct of operations and use of procedures in the control room (Sections 2.2 and 3.4).

- In general, control room operations were conducted in a professional manner. The exchange of information during shift turnovers continued to be excellent (Sections 3.1).

- Reactor plant operators were knowledgeable of plant equipment and their assigned duties and were properly maintaining plant logs (Section 3.2).

Maintenance

- On one occasion, a safety-related motor-operated valve failed to open during surveillance testing (Section 3.4).

- In general, maintenance technicians were knowledgeable and demonstrated good maintenance practices. Maintenance activities were performed in a professional manner (Section 4.4).

- Self-verification techniques, independent verifications, and response to abnormal conditions during maintenance activities were in accordance with management expectations (Section 4.3).

- One instance of inadequate equipment clearance or tagging was observed (Section 4.3).

- Maintenance packages reviewed were executed in accordance with the appropriate procedures (Section 4.4).

- During testing of an auxiliary feedwater pump, the performance of the prejob briefing was excellent (Section 5.2).

- In general, the surveillance testing observed indicated that licensee personnel were appropriately testing plant equipment in accordance with Technical Specifications (Section 5.4).

Engineering

- The Group Vice President, Nuclear committed to develop a plan of action for further evaluation and testing of the control rods and to present this plan to the NRC (Section 2.2).

- Engineering calculations supported relaxed standby diesel generator essential cooling water flow rate requirements recommended to the shift supervisor while the essential chillers were aligned for cold weather operations (Section 7.1).

Plant Support

- One noncited minor violation was documented because combustible material was not maintained in accordance with the control of transient fire loads procedure (Section 3.2).

- Daily plant health physics activities observed were acceptable (Section 6.1).

- Daily security force operations were handled in an appropriate manner (Section 6.2).

- NRC emergency site team badges and provisions for their use were in place (Section 6.2).

- Plant chemistry and radiation monitoring was being adequately controlled (Section 6.3).

Summary of Inspection Findings:

- Unresolved Item 498;499/95029-01 was opened (Sections 2.1 and 3.4).

- Violation 498;499/94024-02 was closed (Section 9.1).

- Violation 498;499/94017-01 was closed (Section 10.1).

- Violation 498/94035-02 was closed (Section 11.1).

- Inspection Followup Item 498;499/93031-32 was closed (Section 8.1).

- Licensee Event Report 499/94-006 was closed (Section 9.2).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1 Plant Status

At the beginning of this inspection period, Unit 1 was operating at 100 percent reactor power.

On December 18 at 3:36 a.m., the Unit 1 reactor tripped on a turbine trip signal caused by a main transformer lockout. The lockout was caused by the combination of a fault on an offsite transmission line and a grounded current transformer in the main transformer differential relay circuit. The reactor coolant system was stabilized in Mode 3 at normal operating temperature and pressure.

On December 21, Unit 1 entered Mode 2 and was made critical at 5:48 a.m. Mode 1 was entered at 11:11 a.m. The main generator output breaker was closed at 6:43 p.m. and power ascension commenced. The reactor was maintained at low power while secondary chemistry was restored to within specifications. Reactor power was increased to 100 percent on December 23.

At the end of this inspection period, Unit 1 was operating at 100 percent power.

1.2 Unit 2 Plant Status

At the beginning of this inspection period, Unit 2 was operating at 92 percent reactor power with ascension to 100 percent in progress. The unit achieved 100 percent power on November 20.

On December 19, reactor power was reduced to 98 percent in response to an increase in main generator stator winding end vibration.

On December 21, reactor power was further reduced to 95 percent in response to continued increase in main generator stator winding end vibration.

On December 27, reactor power was returned to 100 percent power following temporary adjustment of the generator hydrogen cooling system in order to reduce the main generator stator winding end vibration.

At the end of this inspection period, Unit 2 was operating at 100 percent power.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Reactor Trip Because of Main Transformer Lockout (Unit 1)

On December 18, 1995, at 3:36 a.m., while Unit 1 was operating at 100 percent power, a pilot wire monitoring relay actuation caused a main transformer lockout resulting in a turbine trip and a reactor trip. This caused a loss of the unit auxiliary transformer which was one of three sources of offsite power. The loss of the unit auxiliary transformer resulted in a loss of electrical power to all nonessential electrical switchgear and the Train A engineered safety features bus.

Licensee engineers determined that the initiator of the trip was a fault on an offsite power line caused by severe weather in the area. A grounded wire on Phase A of the main transformer backup current transformer for the differential relay had previously existed because of a substation maintenance electrician's error during the previous refueling outage. This ground caused the differential relay to sense a continued current differential after the offsite line fault had been cleared from the grid, which resulted in the trip.

As a result of the event, the following actuations occurred:

- Standby Diesel Generator 11 started and loaded on its associated safety bus, as required.
- All reactor coolant pumps tripped on undervoltage.
- The main feedwater system isolated.
- The auxiliary feedwater system actuated on low steam generator levels.
- A containment vent isolation occurred that resulted in a reactor coolant system letdown isolation.

The operators closed the main steam isolation valves to conserve heat. Main Steam Isolation Valve 1B indicated partially open for about 10 minutes before indicating fully closed. Subsequent investigation determined that the problem had been caused by a faulty limit switch.

One operator noted that all electrical instruments on Main Control Board Panel CP010 were indicating no voltage or current from offsite sources. This instrumentation had lost power because of the main transformer lockout. However, the operator erroneously concluded that offsite power was not available. The operator verified that only Standby Diesel Generator 11 had started. He, therefore, manually started Standby Diesel Generators 12 and 13, even though the associated Buses E1B and E1C never lost offsite power.

After the main steam isolation valves were closed, reactor coolant system pressure increased, as expected, causing Pressurizer Power-Operated Relief

Valve 1-RC-656A to open to maintain pressure. Positive indication that the valve reseated was provided by discharge line temperature monitors indicating that relief line temperatures had returned to ambient. The valve had opened three times before operators established control of reactor coolant system pressure with auxiliary pressurizer spray.

Reactor coolant system natural circulation was established and temperature control was provided by manual control of the steam generator power-operated relief valves. Makeup water was provided by the auxiliary feedwater system. Approximately 1 hour and 30 minutes following the trip, reactor operators started two reactor coolant pumps establishing forced circulation.

The letdown isolation and the centrifugal charging pump taking suction on the volume control tank caused a low water level in the volume control tank approximately 8 minutes after the trip. This resulted in the automatic transfer of the centrifugal charging pump suction to the refueling water storage tank. Water containing a high concentration of boric acid was then pumped to the reactor coolant system.

Immediately following the trip, the digital rod position indication system indicated that Rod Cluster Control Assemblies C9, F10, and N7 were not fully inserted. The rod bottom lights were not illuminated and the indication placed the assemblies at approximately six steps from the bottom of normal travel. About 10 minutes later, the rod bottom light for Rod Cluster Control Assembly N7 illuminated.

During the performance of Plant Operating Procedure OPOP05-EO-ES01, Revision 6, "Reactor Trip Response," one of the emergency operating procedures, reactor operators stopped to question the basis of Step 3. Step 3 required the operators to verify that all control rods were fully inserted. If not, the operators were required to emergency borate 3200 gallons of boric acid for each control rod that failed to insert. The operators questioned whether this step applied to the three rods indicating six steps withdrawn. The shift supervisor stated that he believed that there existed an indication problem and that the rods were actually on the bottom. However, no indication existed to support this conclusion. Additionally, the operators did not believe that three rods a few steps out were sufficient to cause a reactivity problem. Finally, all indications verified that the reactor was, in fact, shut down. Therefore, the unit supervisor documented that all rods were fully inserted and continued with the next step in the procedure. At 6:10 a.m., a shutdown margin verification calculation was performed and the reactor coolant system boron concentration was found to be adequate. However, the operators actions did not meet the procedural requirements for emergency boration as indicated in Plant Operating Procedure OPOP04-CV-0003, Revision 3, "Emergency Boration."

Following the event, the licensed operators tested all the control rods within the banks that contained the control rods that had not fully inserted and found a total of four control rods that would not fully insert. The four rods of concern were all stopping in the six-step area (last 4 inches) which is part of the lower dashpot area of the fuel assembly guide tubes. All four fuel assemblies of concern were in their second cycle of use and had received a high fuel burn up. With the four control rods at the Step 6 position, the licensee determined that the shutdown margin was adequate. There were no noted differences in rod drop times prior to reaching the upper dashpot area. At the end of this inspection period, the licensee and the fuel supplier were still evaluating the test data and fuel design information.

On December 20, licensee management presented the interim findings of their review and evaluation to the NRC on a telephone conference call. Licensee engineers had bound the problem sufficiently to permit restart of the unit. During this conference call, licensee management committed to develop a plan of action for further evaluation and testing of the control rods and to present this plan to the NRC. The NRC program office will evaluate the cause of the control rods not fully inserting.

The apparent failure of the control room operators to follow the requirements of the emergency operating procedures raised questions of the attitude and decision-making techniques of licensed operators in the control room. These questions are considered unresolved. These items will be tracked as Unresolved Item 498;499/95029-01 and will be reviewed and documented in NRC Inspection Report 50-498/96-12; 50-499/96-12.

Also on December 20, prior to the unit restart, the resident inspectors observed portions of the startup training for the operators involved in the restart of the reactor. As part of this training, the Manager, Unit 1 Operations briefed the crew on the lessons learned from this event. The discussion focused on emergency operating procedure compliance. The statement "Verify All Control Rods - Fully Inserted" was defined as follows:

> Control rods are fully inserted if the digital rod position indication system rod bottom lights so indicate. If two or more control rods do not have rod bottom lights lit then, in accordance with Procedure OPOP05-EO-ES01, an emergency boration shall be commenced.

In response to the concerns regarding operators questioning the basis of emergency operating procedures during an event, licensee management issued the following statement:

> The Emergency Operating Procedures have been designated to limit the need for personnel involved in plant transients to make subjective determinations of plant conditions under duress. Our expectation is that all EOP procedure requirements will be followed. Exceptions to these requirements should only be made when the Shift Supervisor has clear indication that personnel or unit safety would be compromised. Whenever possible, decisions not to perform EOP procedure steps should be made in consultation with Operations Management or the Emergency Director.

The inspectors determined that the proper emphasis and seriousness was applied to the subject and that the appropriate guidance was delivered. During interviews the following day, the inspectors determined that licensed operators fully understood the guidance.

2.2 Conclusions

The Unit 1 reactor tripped as a result of an offsite grid disturbance and inadequate maintenance of a switchyard relay. An unresolved item was established to track and evaluate the conduct of operations and use of procedures in the control room. Further NRC program office analysis of the failure of control rods to fully insert following the Unit 1 reactor trip is planned. The Group Vice President, Nuclear committed to develop a plan of action for further evaluation and testing of the control rods and to present this plan to the NRC regional and program offices.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was operated safely and in conformance with license and regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. The following paragraphs provide details of selected, specific inspector observations during this inspection period.

3.1 Control Room Observations

During this inspection period, the inspectors observed activities in the control rooms of both units during normal, backshift, and weekend hours. During these observations, the licensed operators performed in a professional manner. Alarm response was prompt and accurate with good use of annunciator response procedures. Communications techniques utilized by control room operators were formal and closed loop. Communications with reactor plant operators in the plant were also very good. The inspectors routinely verified that control room staffing met the minimum requirements of Technical Specification 6.2.2.a. and that operators were not distracted by nonwork related items in the control room.

The inspectors routinely toured the control panels and observed safety-related indications. The availability of offsite power was verified. The inspectors verified through lack of annunciation, valve position indication, and pump breaker indication that the emergency core cooling systems were maintained in proper standby alignment. During observations of shift turnover activities, the inspector determined that licensed operators continued to provide an excellent exchange of equipment status and plant condition information.

3.2 Plant Tours

Throughout this inspection period, the inspectors toured the mechanical auxiliary buildings, electrical auxiliary buildings, and turbine-generator buildings of both units. The inspectors routinely reviewed log books kept at local reactor plant operator stations. Reactor plant operators were observed during the performance of their duties and were found to be knowledgeable of plant equipment and their assigned duties.

On December 13, 1995, the inspector toured the Unit 1 mechanical auxiliary building and fuel handling building. Material condition of the components and systems appeared to be good. The inspector observed that, while Fire Door 1-MAB-Door-086 on the 10-foot elevation in the mechanical auxiliary building corridor for Room 67A would close, it would not latch shut. The on-call site fire protection engineer was notified of the defective door, and the latch was repaired.

On December 14, the inspector toured the Unit 2 mechanical auxiliary building and fuel handling building. Material condition of the components and systems appeared to be good. The inspector observed a bulk storage of transient combustible material that included trash, plastic bags, old insulation, and other miscellaneous items. This material was inappropriately stored in the southwest corner of the nonradioactive piping penetration area (Fire Area 3, Fire Zone Z116) on the 41-foot elevation of the mechanical auxiliary building. The volume of bulk storage of combustible material was approximately 10-feet wide by 10-feet long by 2-feet high. The inspector notified the on-call site fire protection engineer of the unacceptable bulk storage of combustible material in the identified safe-shutdown equipment area.

The fire protection engineer immediately performed a survey tour of Fire Zone Z116, issued Condition Report 95-14339 to document the unacceptable bulk storage of combustible material, and requested removal of the combustible material to the trash sorting area. The fire protection engineer stated that 1-hour fire tours would be established in Fire Zone Z116 until the identified combustible material was removed.

Plant General Procedure OPGP03-ZF-0004, Revision 1, "Control of Transient Fire Loads," Section 4.14 stated, in part, that:

> plant areas shall not be used for bulk storage of combustible material except as evaluated by the fire protection coordinator and approved by management (department manager or above). Such storage shall be posted (including required precautions and storage conditions) using Combustible Material Storage Authorization Form (-1).

The inspector observed that on December 14 there was no Combustible Material Storage Authorization Form posted in Fire Zone Z116 for the bulk storage of the combustible material observed by the inspector. The fire protection engineer assured the inspector that the corrective actions taken in response to Condition Report 95-14339, would identify the cause for the introduction and accumulation of transient combustible material in a safe-shutdown equipment area and establish a plan to preclude recurrence.

The inspector noted that the safety significance of this violation was minor because the governing procedure would have permitted this condition if the procedure had been properly implemented. The inspector further noted that Fire Zone Z116 contained both smoke detectors and a fire protection sprinkler system. In addition, the inspector reviewed the disposition of Condition Report 95-14339. Licensee personnel had removed the material the same evening that it had been identified.

This failure to follow procedure for the control of transient fire loads constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

3.3 Component Cooling Water System Flow Path Verification (Unit 2)

On December 18, the inspector performed a flow path verification of the accessible portions of the Unit 2 component cooling water system in the mechanical auxiliary building. The inspector verified valve positions, electrical breaker alignments, and that power was aligned to the system controls. The material condition of the system was very good and no discrepancies were identified.

3.4 Safety Injection Valve Failure to Stroke During Surveillance Testing

On December 23, during the performance of Plant Surveillance Procedure OPSP03-SP-0009B, Revision 5, "SSPS Actuation Train B Slave Relay Test," Containment Sump to Safety Injection System Suction Header Isolation Valve 2-SI-MOV-0016B failed to open during the performance of Step 5.6.25. The operators determined that an open signal had been generated by the protection system. However, the valve motor breaker tripped, preventing valve actuation. Procedural Step 5.6.26 required the operators to verify that an open indication was displayed in the main control room for Valve 2-SI-MOV-0016B. This step was marked with an "AC," indicating that the completion of the step was an acceptance criteria for the surveillance test. In addition, Section 6, Step 6.1, listed Step 5.6.26 as an acceptance criteria. The operators reset the breaker and the valve completed its stroke to the full open position.

Plant General Procedure OPGP03-ZE-0004, Revision 15, "Plant Surveillance Program," stated in Section 4.4.6:

> IF surveillance test results are unsatisfactory or do not meet the acceptance criteria, as specified by the surveillance procedure, THEN the surveillance is considered failed (unsatisfactory) and the Shift Supervisor is notified. Furthermore, IF the test data obtained during the performance of a surveillance test indicates that the acceptance criteria will not be satisfied, THEN the surveillance, once completed, is considered failed (unsatisfactory).

However, an exception in Subsection 4.4.6.1 stated:

> An exception to Step 4.4.6 is allowed IF during the surveillance test a deficiency is noted that can and SHOULD be corrected/resolved by immediate test coordinator or operator actions without the generation of an additional/external documentation (i.e., CR, etc.) and not within the scope of existing deficiency programs (Ref. 5.31). In those cases the appropriate action(s) SHOULD be taken, the surveillance test completed and the corrected deficiency documented in the surveillance test data package. This step does not allow the Test Coordinator to bypass procedural requirements under existing maintenance rules and procedures.

The shift supervisor evaluated the test and noted that the surveillance test was being performed to verify that the relays actuated and not that the valve opened. Therefore, he indicated that the test had not failed. Following the breaker reset, reactor operators cycled the valve several times. The appropriate portion of the test was reperformed, and the valve opened as designed.

The inspectors reviewed the test data package and noted that the comments section included a discussion of the incident. However, the test cover sheet indicated that all acceptance criteria had been passed. Additionally, the control room logs did not clearly address the issue. The shift supervisor issued Condition Report 95-14538 to address the condition of Valve 2-SI-MOV-0016B. The licensee did not determine the cause of the breaker trip as part of its initial response to the condition report, which remains open.

The inspectors questioned the decision making process utilized by the shift supervisor. In addition, the actions taken appeared to be in noncompliance with Procedure OPGP03-ZE-0004. Licensee management stated that the shift supervisor had met their interpretation of the requirements of this procedure. The review of the procedural compliance and the decision-making process of the shift supervisor during this event will be tracked as an additional example of Unresolved Item 498;499/95029-01. The review of this item will be documented in NRC Inspection Report 50-498/96-12; 50-499/96-12.

3.5 Conclusions

In general, control room operations were conducted in a professional manner. Emergency core cooling system alignments were properly maintained, and the component cooling water system flow path was verified with no discrepancies. The exchange of information during shift turnovers continued to be excellent.

Reactor plant operators were knowledgeable of plant equipment and their assigned duties and were properly maintaining plant logs. On one occasion, inspectors observed a large volume of combustible material not maintained in accordance with the procedure for control of transient fire loads. This constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

On one occasion, a safety-related motor-operated valve failed to open during surveillance testing. This was the second example of the unresolved item opened to evaluate the procedural compliance and decision-making process of the licensee.

4 MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC regulations. The inspectors verified that the activities were conducted in accordance with approved work instructions and procedures, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. Activities witnessed included work in progress, postmaintenance test runs, and field walkdown of the completed activities. Additionally, the work packages were reviewed and individuals involved with the work were interviewed. All observations made were referred to the licensee for appropriate action.

4.1 Troubleshooting and Repair of Main Turbine First Stage Pressure Transmitter PT-506 (Unit 1)

On December 12, 1995, the inspector observed instrumentation and controls technicians, working under direct supervision, perform portions of the troubleshooting phase and corrective actions for Work Order 95-324062. The work order documented that First Stage Pressure Transmitter 1-PT-506 was reading erratically. The transmitter was found to be indicating from 250 to 450 psig with the unit operating at 100 percent power. The inspector observed technicians replacing Turbine Impulse Chamber Pressure Transmitter 1-D1MS-PT-506. The measuring and test equipment and the tools utilized during the troubleshooting, work, and postmaintenance testing were in current calibration, and the transmitter was replaced in accordance with approved procedures in a step-by-step fashion.

The technicians exhibited a detailed knowledge of the components and interrelated systems associated with this maintenance effort.

4.2 Troubleshooting and Repair of a Containment Supplementary Purge Supply Valve (Unit 1)

On December 13, the inspector observed technicians performing the troubleshooting phase and repair of the reactor containment building supplementary purge supply valve installed at Penetration M-43. Penetration M-43 was declared inoperable when the damper failed a local leak rate test. Additional testing identified that Air-Operated Valve 1-FV-9776, installed outside the containment at Penetration M-43, had an unacceptable seat leak rate.

The valve was removed, the valve seat replaced, and the valve reinstalled. The technicians exhibited a detailed knowledge of the component, and supervisors were observed at the work site during various phases of the work. The inspector reviewed the work package and determined that the instructions were clear and well organized. The technicians were knowledgeable and familiar with the implementation of the instructions. A satisfactory local leak rate test was performed on Penetration M-43, and the valve was declared operable.

4.3 Essential Chiller 21B Compressor Lubrication Oil Pressure Switch Calibration (Unit 2)

On December 18, the inspector observed electrical maintenance personnel performing Preventive Maintenance Activity PM:EM-2-CH-9003083, Revision 0. This procedure directed the calibration of the lubricating oil pressure switch for Essential Chiller 21B. The inspector verified that an appropriate equipment clearance order had been established. While reviewing the instructions for the activity, the electrician identified a control power switch that had not been included in the equipment clearance order. The electrician promptly added a test tag for the switch to the equipment clearance order. The inspector observed the electricians using independent verification techniques during the isolation and restoration of the pressure switch in accordance with Plant General Procedure OPGP03-ZM-0021, Revision 8, "Control of Configuration Changes." The inspector also observed good self-verification techniques in use throughout the activity. The inspector verified the release of the equipment clearance order and satisfactory postmaintenance testing of the essential chiller.

4.4 Conclusions

In general, maintenance technicians were knowledgeable and demonstrated good maintenance practices. Abnormal conditions were properly identified, and technicians immediately involved supervision when problems arose. Self-verification techniques and independent verifications observed were in accordance with management expectations. Maintenance activities were performed in a professional manner. Coordination among the crafts was very good. Additionally, maintenance packages reviewed had been executed in accordance with the appropriate procedures.

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were performed in accordance with the licensee's approved programs and Technical Specifications.

5.1 Containment Spray Pump 1B Feeder Breaker Relay Calibration (Unit 1)

On December 12 and 13, 1995, the inspector observed instrumentation and controls technicians performing portions of Preventive Maintenance Activity PM:EM-1-PK-8701F081, Revision 2.0, "Calibrate Relay/Device

(Cubicle 10)," on the Containment Spray Pump 1B feeder breaker. The inspector verified that the equipment clearance order had been established and that the specific relays and devices being tested were isolated during the surveillance activity. The inspector also verified that the electricians were using approved instructions. The electricians used good self-verification techniques. Dual verification was also utilized by the electricians when procedurally required. Relays and devices were checked, adjusted, and calibrated, as necessary, in accordance with the instructions in the approved procedures.

The inspector also verified that the calibration of the measuring and test equipment used for these surveillance tests had been performed within the established calibration cycle.

5.2 Auxiliary Feedwater Pump 11 Inservice Test (Unit 1)

On December 8, the inspector observed the monthly inservice test of Auxiliary Feedwater Pump 11. The test was performed in accordance with Plant Surveillance Procedure OPSP03-AF-0001, Revision 3, "Auxiliary Feedwater Pump 11(21) Inservice Test." The inspector determined that the communications techniques and attention to detail utilized during the prejob briefing were noteworthy. The test coordination was good and no discrepancies were identified.

5.3 Standby Diesel Generator 22 Operability Test (Unit 2)

On December 19, the inspector observed portions of the operability test of Standby Diesel Generator 22. The test was performed in accordance with Plant Surveillance Procedure OPSP03-DG-0002, Revision 2, "Standby Diesel 12(22) Operability Test." The inspector observed the actuation of the solid-state protection system slave relay for the diesel generator starting circuit. The inspector observed good communications techniques among senior reactor operators and instrumentation and controls technicians. Good independent and self-verification techniques were used.

The inspector accompanied the shift supervisor on a walkdown of the diesel generator while the machine was running fully loaded. The shift supervisor identified three small flange leaks on the diesel generator jacket cooling water system. A condition report was developed to address the leaks.

The overall performance of the surveillance activity was very good. The coordinated effort was well planned and executed.

5.4 Conclusions

In general, the surveillance testing observed indicated that licensee personnel were appropriately testing plant equipment in accordance with Technical Specifications. The surveillance tests were performed in a professional manner. Communications techniques used by those involved in the testing of the auxiliary feedwater pump were noteworthy. The test performers were knowledgeable of the testing requirements and associated equipment. Supervisory oversight was observed, and self-verification and independent verification techniques were utilized properly.

6 PLANT SUPPORT ACTIVITIES REVIEW (71750)

The objectives of this inspection were to ensure that selected activities of the licensee's support programs were implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

6.1 Health Physics Activities

During routine tours of the plant, the inspectors observed that postings and labeling of areas and radioactive materials were in compliance with the regulations and the licensee's procedures. A sample of doors required to be locked for the purpose of radiation protection were verified to be secured. Plant workers were observed to be in compliance with the appropriate radiation work permits and were knowledgeable of plant radiological conditions. The inspectors verified that NRC Form 3 and Notices of Violation had been posted in accordance with 10 CFR 19.11.

6.2 Physical Security Observations

The security force searched packages and personnel professionally. Vital area doors were verified locked and in working condition. Protected area barriers were properly maintained and in good condition. The inspectors verified that isolation zones around protected area barriers were maintained free of equipment and debris. During backshift tours, the inspectors determined that the protected area was properly illuminated. The inspectors reviewed the emergency access badges and provisions for the NRC emergency site team and found them to be in order.

6.3 Plant Chemistry and Monitoring Reviews

The inspectors routinely observed indications that plant water chemistry and radioactivity were within the Technical Specification limits. Chemistry reports were reviewed, radiation monitoring traces observed, and main control room logs audited. Annunciator status and the secondary plant Nitrogen-16 monitoring equipment indicated that steam generator tube integrity was maintained. Additionally, the inspectors audited the status of meteorological indication.

6.4 Conclusions

Daily plant health physics activities observed were acceptable. Daily security force operations were handled professionally. Plant chemistry and radiation monitoring was being adequately controlled. NRC emergency site team badges and provisions for their use were in place.

7 EVALUATION OF ONSITE ENGINEERING (37551)

The objective of this inspection was to provide periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. The inspector periodically investigated engineering problems or incidents to determine the root cause of the selected engineering problem. The effectiveness of licensee's controls in identifying, resolving, and preventing problems by reviewing such areas as corrective action systems, root cause analysis, safety committees, and self-assessment in the area of engineering was evaluated. The following paragraphs provide details of selected specific inspector reviews during this inspection period.

7.1 Review of Essential Cooling Water Flow to the Standby Diesel Generators (Unit 1)

On December 26, 1995, while preparing to perform Plant Surveillance Procedure OPSP03-DG-0003, Revision 5, "Standby Diesel 13(23) Operability Test," the reactor operators determined that essential cooling water system flow to Standby Diesel Generator 13 was greater than the maximum flow rate allowed by the procedure. Procedural Step 5.2.1 in the Prestart Inspection Section 5.2 required that the operators ensure the essential cooling water system was providing between 1486 and 1743 gpm cooling flow to the diesel. Upon observation of Essential Cooling Water Return Flow Indicator 1-EW-FI-6875, reactor plant operators determined that the flow rate to the diesel was between 1760 and 1770 gpm.

The shift supervisor suspended the test and requested that design engineering personnel evaluate the flow rate and recommend the course of action. Because the flow was higher than the minimum required flow, all other system flow rates were within specifications, and the system had recently been placed in cold weather operations, the shift supervisor determined that the standby diesel generator continued to be operable while evaluating the condition. The following day, operators performed Procedure OPSP03-DG-0003 after an essential cooling water system flow balance had been performed, and the procedural cooling flow rate acceptance criteria were satisfied.

The inspector reviewed Calculation MC-6429, Revision 0, "Cold ECW Chiller Analysis." This calculation addressed, in part, the essential cooling water system flow rates required while the essential chilled water system chillers were aligned for cold weather operations. Section I of the calculation addressed the essential cooling water system flow balance. Section I stated:

> The design flows through the 150 ton and 300 ton chiller condensers are 600 and 1100 gpm, respectively. Reducing these flows to 0 and 240 gpm will increase the flow to the remaining components. The ECW operating procedure currently includes maximum flow limits as well as minimum flows. The maximum limits are based on consistency with analysis of the transient that occurs when the ECW pump is stopped.

The calculation also provided a basis for allowing flow rates up to 10 percent higher as an upper limit. The engineers stated that:

> Without the increase, the reduced flows to the chillers could require minor adjustment of the ECW flow balance. With the revised limits it is unlikely that adjustment of any ECW valves will be required when entering or exiting from 'cold ECW' operation.

Based on this calculation, the maximum permissible flow rate through the standby diesel generator heat exchangers was 1917 gpm. Therefore, the flow rate observed was determined to be acceptable. Licensee engineers planned to revise the procedure to allow additional flow while the essential cooling water system was in the cold weather operations alignment.

The inspector determined that the shift supervisor's actions had been appropriate and that the engineering calculations fully supported the decision to allow higher cooling water flow rates through the standby diesel generators with the essential chilled water system chillers in the cold weather operations alignment.

7.2 Conclusions

Engineering calculations supported the relaxed standby diesel generator essential cooling water flow rate requirements recommended to the shift supervisor while the essential chilled water system chillers were aligned for cold weather operations.

8 FOLLOWUP ON AN OPEN OPERATIONS ITEM (92901)

8.1 (Closed) Inspection Followup Item 498;499/93031-32: Periodic Evaluation of Department Management Team Effectiveness

The South Texas Project Operational Readiness Plan was developed to provide documentation of the improvements that had been deemed necessary prior to the resumption of power operations following the 1993 outages. This inspection followup item had been initiated to track the formation of senior management and department management teams. These teams had been formed primarily to support the development of the Business Plan. However, they were proving to be an important means for vertical communications between senior and middle management, and for horizontal communications between departments and, therefore, remained in effect to be utilized for other purposes in the future. At that time, the inspectors documented a need for the NRC to track senior management's periodic evaluation of the teams' effectiveness.

In mid-1994, senior management decided to disband the department management team. The team was replaced with a department level group designated as the change management team. For efficiency and effectiveness, not all departments were represented. Group representatives on the team were expected to act as communications links with the other departments in their group.

The change management team routinely evaluated the independent performance assessments as well as the monthly performance report. This review helped ensure that departments identified the issues and understood the basis for the findings. The senior management team routinely evaluated the change management team's performance at periodic extended meetings. Additionally, a critique of the 1996 Business Plan effort was held during a joint meeting of both teams.

The inspectors reviewed the charter for the change management team and determined that the team's goals and responsibilities were clearly delineated. Team members believed that the team was effective and that its existence was expected to continue into the foreseeable future. The licensee met the restart plan commitments in this area, and NRC tracking of this item was no longer considered necessary.

9 FOLLOWUP ON OPEN MAINTENANCE ITEMS (92902)

9.1 (Closed) Violation 498;499/94024-02: Failure to Properly Perform a Technical Specification Required Channel Check

This violation documented the failure of control room operators to perform a qualitative assessment of the Containment Building Normal Sump Water Level Channel 2-LT-7840. The channel had been reading off-scale low for several months. Operators performing Technical Specification required channel checks had determined that the readings were acceptable because the computer had not indicated that the data point was incorrect, even though no indication was available. However, a maintenance technician identified that the channel breaker was open.

In addition, during the performance of the revised surveillance check, licensed operators determined that Containment Sump Wide Range Water Level Channel 1-LT-3925 was also inoperable for similar reasons.

Licensee management determined that the cause of the event was an inadequate surveillance procedure. The procedure did not provide adequate guidance to allow detection of inoperable channels. Operators immediately shut the breaker and restored the instrument power. The surveillance test was then successfully performed.

The following corrective actions were implemented:

- The surveillance test was performed on both Units 1 and 2 to reevaluate whether the indication was adequate for determining operability. It was determined the reactor containment building sump wide range level instruments (one per unit) had not been adequately evaluated for operability by the existing surveillance procedure. This issue was further addressed in Licensee Event Report 498/94-006, Revision 1, "Failure to Perform an Adequate Instrumentation Channel Check."

- Plant Surveillance Procedure OPSP03-SP-0001, Revision 13, "Remote Shutdown Monitoring, and Accident Monitoring Instrumentation Channel Check," was revised to provide adequate guidance to ensure instrument operability. The inspector reviewed the revision to Procedure OPSP03-SP-0001. This revision provided adequate guidance to the operators to ensure that inoperable instruments would be identified during channel checks. A performance of this procedure was observed by the inspectors as documented in NRC Inspection Report 50-498/95-23; 50-499/95-23.

- This event and the need to monitor for abnormal, excessively low or high channel readings during surveillance testing were discussed with Operations and Maintenance personnel.

The specific event involving Normal Sump Channel 2-LT-7840 had been previously reviewed as documented in NRC Inspection Report 50-498/94-24; 50-499/94-24. The specific event involving the containment sump wide range level instrumentation was reviewed and closed, during the review of Licensee Event Report 499/94-006, as documented in Section 9.2 of this inspection report.

Although the specific surveillance procedure was adequately revised, the generic issue of inadequate plant surveillance procedures will continue to be addressed and tracked under Violation 498;499/94010-01.

9.2 <u>(Closed) Licensee Event Report 499/94-006; Revision 1: Failure to Perform an Adequate Instrumentation Channel Check</u>

This licensee event report documented the failure to properly perform Technical Specification required channel checks and the condition of several instruments that had been inoperable for an extended period as a result. This event was initially reviewed and cited as Violation 498;499/94024-02 as documented in Section 9.1 of this inspection report. During the review, licensed operators had identified that two reactor containment building sump wide range level instruments had not been adequately evaluated for operability by the existing surveillance test. Following maintenance activities, the channels were declared operable. The revision of Procedure OPSP03-SP-0001 was considered appropriate as corrective action for these instrument channels also.

In addition to this specific event, the licensee addressed additional licensee event reports that documented failures to properly implement Technical Specification surveillance requirements as a result of inadequate surveillance testing procedures. As a result, the licensee referred corrective actions to the ongoing Surveillance Procedure Enhancement Program. Since initiation, the program's scope has expanded, and the results of this program continue to be tracked by Violation 498;499/94010-01.

10 FOLLOWUP ON AN OPEN ENGINEERING ITEM (92903)

10.1 (Closed) Violation 498;499/94017-01: Failure to Conduct a Proper Postmodification Test

Prior to the restart of Unit 2 following the 1993 outage, licensee personnel installed modifications to the essential chillers to permit operations with low essential cooling water temperatures. Following the installation, licensee engineers determined that the load testing performed on the Unit 1 chillers had been sufficient to certify the calculations. Therefore, full performance testing of the Unit 2 modification was not required.

Following NRC questioning at that time, a test was performed to verify that the essential chiller bypass line could pass the design flow rate. The bypass line around Essential Chiller 22A would not pass sufficient flow to meet the design basis.

As documented in NRC Inspection Report 50-498/94-17; 50-499/94-17, licensed operators had performed a flow balance of the essential cooling water system, providing more flow to the essential chillers. Flow rate testing had then been performed for the remaining Unit 2 essential chillers as well as for the Unit 1 chiller that had not been previously tested. In addition, sufficient package review and system inspection had been conducted at that time to resolve Restart Issue 12 and permit restart of the unit.

In the licensee's response, dated September 8, 1994, the cause of the violation was determined to be the failure of the system engineer to utilize the "Post-Modification Acceptance Testing Guidelines." Additionally, the section supervisor failed to identify the deficiency during his impact assessment.

The corrective actions were as follows:

- As discussed above, the required flow through the essential chiller essential cooling water outlet bypass valve was verified for both units' essential chillers.

- A training bulletin was provided to the system engineers on lessons learned. The inspector noted that the bulletin discussed the purpose of the "Post-Modification Acceptance Testing Guidelines" procedure, stressed the necessity for adequate communication between applicable system engineers in a multisystem plant modification, and pointed out the importance of the procedures referenced on the impact assessment forms.

- The inspector reviewed Plant General Procedure OPGP04-ZE-0311, Revision 0, "Design Change Functional Test Identification." This procedure clearly defined the differences between prerequisite testing, functional testing, and operability testing. The procedure also provided a "design change type description and testing matrix" to assist the engineer in selecting and specifying appropriate postmodification tests.

These actions were sufficient to correct the specific item and prevent recurrence of a similar failure to designate proper testing.

11 ADMINISTRATIVE CLOSURE: NRC RETRACTED VIOLATION (90712)

11.1 (Closed) Violation 498/94035-02: Inappropriate Testing of Molded Case Circuit Breakers.

This violation was originally cited because technicians were preconditioning safety-related circuit breakers prior to testing in accordance with Surveillance Requirement 4.8.4. The testing method required the technicians to cycle the breakers five times prior to testing the electrical trip characteristics. This raised a question of potential loss of information about poorly functioning breakers.

In the licensee's response dated February 22, 1995, they denied that a violation had occurred. Licensee engineers stated that the basis for Surveillance Requirement 4.8.4 was to test molded case circuit breakers in accordance with NEMA Standard Publication AB 2-1980. NEMA AB 2-1980, Part 3, Section C, stated that "prior to the electrical operation tests, the mechanical operation of the circuit breaker should be checked by turning it on and off several times."

In a letter dated April 17, 1995, the NRC concurred that the licensee was meeting the requirements of Technical Specifications and, therefore, was not in violation. However, the NRC expressed concern that this method of performing surveillance tests on molded case circuit breakers may not have been the most representative surveillance test for demonstrating circuit breaker operability. This concern continues to be under review for generic implications by the NRC.

Based on the information currently on the docket, this item is administratively closed.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

J. Calloway, Owner Liaison
T. Cloninger, Vice President, Nuclear Engineering
K. Coates, Manager, Unit 2 Maintenance
W. Cottle, Group Vice President, Nuclear
B. Dowdy, Manager, Unit 2 Operations
R. Englmeier, Manager, Nuclear Safety Quality Concerns Program
R. Fast, Manager, Unit 1 Maintenance
J. Groth, Vice President, Nuclear Generation
E. Halpin, Manager, Systems Engineering Department
S. Head, Supervisor, Compliance
D. Leazar, Director, Nuclear Fuel and Analysis
J. Lovell, Manager, Unit 1 Operations
F. Mangan, General Manager, Plant Services
L. Martin, General Manager, Nuclear Assurance and Licensing
B. Masse, Plant Manager, Unit 2
M. McBurnett, Manager, Licensing
L. Myers, Plant Manager, Unit 1
G. Parkey, General Manager, Generation Support
R. Rehkugler, Director, Quality
D. Schulker, Compliance Engineer
J. Sheppard, Assistant to Group Vice President
D. Stonestreet, Outage Manager
S. Thomas, Manager, Design Engineering Department
G. Walker, Manager, Public Information

The personnel listed above attended the exit meeting. In addition, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on January 2, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the information presented at the exit meeting. The Group Vice President, Nuclear stated that the organization continued the efforts to understand and address the technical and personnel issues that resulted from the Unit 1 reactor trip. Licensee personnel did not identify as proprietary any information provided to, or reviewed by, the inspectors.