UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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April 28, 2000

Mr. C. L. Terry
TXU Electric
Senior Vice President & Principal Nuclear Officer
ATTN: Regulatory Affairs Department
P.O. Box 1002
Glen Rose, Texas 76043

SUBJECT: NRC INSPECTION REPORT NO. 50-445/00-01; 50-446/00-01

Dear Mr. Terry:

This refers to the inspection conducted on February 13 through April 1, 2000, at the Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed report presents the results of this inspection.

During the 7-week period covered by this inspection, your conduct of activities at the Comanche Peak facility was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Joseph I. Tapia, Chief
Project Branch A
Division of Reactor Projects

Docket Nos.: 50-445
50-446
License Nos.: NPF-87
NPF-89

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NRC Inspection Report No.
50-445/00-01; 50-446/00-01

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-445 50-446
License Nos.:	NPF-87 NPF-89
Report No.:	50-445/00-01 50-446/00-01
Licensee:	TXU Electric
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56 Glen Rose, Texas
Dates:	February 13 through April 1, 2000
Inspectors:	Anthony T. Gody, Senior Resident Inspector Scott C. Schwind, Resident Inspector
Approved By:	Joseph I. Tapia, Chief, Project Branch A

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Comanche Peak Steam Electric Station, Units 1 and 2
NRC Inspection Report No. 50-445/00-01; 50-446/00-01

Operations

- Operators responded well to a loss of instrument air when instrument air compressor 2-02 tripped and 2-01 failed to start and load properly due to a failed lube oil pressure switch. The inspector concluded that the compensatory actions needed to start compressor 2-01 constituted an operator work-around per the licensee's management policies but was not documented as such. This issue was also identified during a recent Operations Department self assessment (Section O4.1).

Maintenance

- During replacement of the inboard and outboard bearings on Containment Spray Pump 2-02, excessive wear was observed on the inboard bearing. Following bearing replacement, the pump and motor were realigned within allowable tolerances. The inspector concluded that the misalignment had no adverse affect on pump operability (Section M2.1).

Engineering

- The licensee identified an issue where some emergency diesel generator relays were powered from the opposite unit in January 1999. The licensee appropriately wrote a Smart Form and determined that equipment operability was maintained because of the redundant nature of the affected emergency diesel generator relays. The full scope of the shared power source issue was not realized until January 2000, when a peer review was being conducted for a proposed change to the Final Safety Analysis Report. The power sources for Panels XEC1-1 and XEC2-1 were swapped to their alternate alignment as recommended by engineering, but it was later found to be an unnecessary manipulation of the plant because Panels XEC1-1 and XEC2-1 contained safety-related loads for both units. The licensee determined that no loss of safety function would occur if power was lost to either Panel XEC1-1 or XEC2-1. The peer review was conducted at the appropriate time during the corrective action process (Section E2.1).

Plant Support

- During an emergency preparedness drill, the fire brigade was called to respond to a simulated fire in the Unit 1, Train A, diesel generator. The fire was extinguished in approximately 30 minutes. Communications between the scene of the fire and the control room simulator were hampered by poor radio reception in the area. Personnel continued to rely on radio communications despite the availability of a plant public address station nearby. Fire brigade members displayed sound decision making by extinguishing the fire with dry chemical agents rather than spraying cold water on the diesel turbocharger while the engine was simulated to be running (Section P1.1).

Report Details

Summary of Plant Status

Both units operated at approximately 100 percent power for the entire report period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was safety-conscious; specific events and noteworthy observations are detailed in the sections below. Through daily observations of control room activities, the inspectors concluded that both units were operated by knowledgeable operators using good self-verification techniques and communications. Instrument air system reliability problems posed a challenge for operators and is discussed in Section O4.1 below.

O2 Operational Status of Facilities and Equipment

O2.1 Plant Tours and Walkdowns

a. Inspection Scope (71707)

Using Inspection Procedure 71707, the inspector conducted tours and walkdowns of the following plant areas:

Units 1 and 2 safeguards buildings
Units 1 and 2 control room
Units 1 and 2 auxiliary building
Units 1 and 2 fuel handling buildings
Units 1 and 2 electrical control building
Units 1 and 2 turbine buildings

b. Observations and Findings

The inspectors found equipment in their proper standby or operating alignment. Temporary equipment was stored and routed properly so as not to adversely affect safety-related equipment.

O2.2 Engineered Safeguards Features Walkdown

a. Inspection Scope (71707)

The inspector performed a walkdown of accessible portions of the Units 1 and 2 chemical and volume control system (CVCS) to assess material condition and verify system alignment. The latest CVCS system health report was reviewed and discussed with the system engineer.

b. Observations and Findings

Material condition of the CVCS was generally good. No active leaks were noted on any of the accessible valves and there were no degraded system conditions noted, with the exception of control room indication of the Unit 1 centrifugal charging pump common suction high point vent valve, 1-HV-8220. There are two separate indications of valve position in the control room, one of which would not indicate open during valve stroke testing. The licensee verified that the valve was opening on demand through local observations. Initial attempts to repair a reed switch on the valve which provided valve indication were unsuccessful and further corrective maintenance was deferred until the next Unit 1 refueling outage. To prevent noncondensable gas buildup in the pump suction line, compensatory actions were placed into effect to perform a weekly vent of the charging pump suction. All other portions of the system were in good condition and appropriately aligned for current plant conditions.

c. Conclusions

A walkdown was performed on accessible portions of the chemical and volume control system. No system leaks were observed and all equipment was appropriately aligned for current plant conditions. The material condition of the system was good, with the exception of the Unit 1 centrifugal charging pump common suction high point vent valve which was not indicating properly in the control room. Adequate compensatory actions were being taken for this condition.

O4 Operator Knowledge and Performance

O4.1 Unit 2 Loss of Instrument Air

a. Inspection Scope (71707)

The inspector reviewed the events leading to a loss of both Unit 2 instrument air compressors and operator response to the event.

b. Observation and Findings

On March 13, 2000, Instrument Air Compressor (IAC) 2-02 was in service with IAC 2-01 in standby when control room operators received an annunciator alarm indicating the IAC 2-02 had tripped. IAC 2-01 attempted to start but immediately tripped due to low lube oil pressure. Operators appropriately entered Abnormal Operating Procedure (ABN) 301 for loss of instrument air and dispatched plant equipment operators to the Unit 2 turbine building to investigate the cause of the trip and to start IAC X-02 and align it to Unit 2. Personnel were able to start and align IAC X-02 to Unit 2; however, the air receiver was depressurized since it had not been operated in several days. Therefore, it was several minutes before the compressor had re-pressurized the receiver and was supplying air to Unit 2 systems. At the same time, operators realized that it was not uncommon for IAC 2-01 to trip on low oil pressure during initial startup and, if reset, would most likely start and run without any further problems. This was done and IAC

2-01 started supplying air to the header at approximately the same time as IAC X-02. Unit 2 was without any compressors in service for approximately eight minutes. During that time, air pressure dropped from a nominal 110 psig to 65 psig prior to starting the two additional compressors. As a result, the 45 gpm letdown orifice isolation valve failed closed. Operators took manual control of charging flow and were able to maintain level in the pressurizer as well as the volume control tank until instrument air was restored. No other systems were adversely affected by the low air pressure.

Following the event, the inspector questioned operators on the reliability of IAC 2-01. Most of the operators on watch during the event knew that the compressor had a history of tripping during initial startup and would run if reset. This condition was initially identified in December, 1999 and documented in Smart Form SMF-1999-003398-00. The inspector reviewed Operation Department Guideline No. 36, "Operator Work-Arounds (WAL)" which defined an operator work-around as "equipment... that represents a potential obstacle to safe plant operation by requiring operators to take compensatory or other than normal actions to comply with procedures, design requirements, ..." . The inspector noted that the required compensatory actions necessary to start IAC 2-01 were not documented as an operator work-around which could have further complicated recovery of the instrument air system had operators been unaware of the required compensatory actions. This issue was also identified by the licensee during a recent Operations Department Self Assessment.

c. Conclusions

Operators responded well to a loss of instrument air when instrument air compressor 2-02 tripped and 2-01 failed to start and load properly due to a failed lube oil pressure switch. The inspector concluded that the compensatory actions needed to start compressor 2-01 constituted an operator work-around per the licensee's management policies but was not documented as such. This issue was also identified during a recent Operations Department self assessment.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-446/00001: missed surveillance test for molded case circuit breakers. The licensee failed to conduct molded case circuit breaker testing in accordance with the prescribed frequency required by Technical Requirements Manual Section 13.8.32.2 for breaker Types EB1010, FH, LH, QOB, and FY in mid-1999. This issue is in the licensee's corrective action program as Smart Form SMF 1999-3504-00.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726, 62707)

In general, maintenance and surveillance activities were characterized by

knowledgeable maintenance personnel. Quality and skill of the craft were evident in the maintenance activities observed.

M1.2 Maintenance and Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspectors observed the maintenance and surveillance activities listed below.

Unit 1, centrifugal charging pump common suction vent valve corrective maintenance
Unit 1, Train B emergency diesel generator corrective maintenance
Unit 2, Train B emergency diesel generator preventive maintenance
Unit 1, turbine-driven auxiliary feedwater pump corrective maintenance
Unit 2, turbine-driven auxiliary feedwater pump quarterly surveillance test
Unit 1, turbine-driven auxiliary feedwater pump quarterly surveillance test
Unit 2, Nuclear Instrument N32 quarterly surveillance test
345 kV Switchyard Breaker 7970 maintenance

Overall, the inspectors observed that maintenance and surveillance activities were conducted in accordance with licensee procedures. Good personnel safety practices and effective communications were evident.

The inspector observed portions of troubleshooting activities on the Unit 1, Train A, centrifugal charging pump suction vent valve, 1-HV-8220. This was a solenoid operated valve which was indicating improperly in the control room. Troubleshooting activities required personnel to work in an overhead high radiation area of Room 77A. Actual dose rates in the work area were approximately 4 millerem per hour. Personnel demonstrated good as-low-as-reasonably-achievable (ALARA) practices.

The inspector observed corrective and preventive maintenance on the Unit 1, Train B, emergency diesel generator. This included replacement of a thermocouple selector switch on the diesel control panel, and an inspection of the exhaust silencer for corrosion. This inspection was done as part of a corrective action for a personnel hazard when pieces of corrosion product were being ejected from the exhaust while the diesel was running. This condition did not affect the operability of the diesel generator. The licensee believed that baffle plates in the silencer were corroding due to the formation of acid when moisture and exhaust products combined in the silencer. The silencer is essentially a large baffled tank in line with the diesel exhaust pipe, approximately 10 feet from the end of the exhaust pipe. The inspection only covered the first baffle plate since personnel access further up the exhaust pipe was restricted. The licensee appropriately treated this area as a confined space and a foreign material exclusion zone.

The inspector observed portions of the maintenance and testing on Breaker 7970 in the 345 kV switchyard. Breaker 7970 is the east bus supply breaker for Transformer XST2, which normally supplies the Unit 1 Class 1E busses. Personnel in the switchyard observed applicable electrical safety precautions and activities were conducted so as

not to affect any other equipment. The work scope encompassed a 4-day period, during which, routine work was scheduled for the Unit 1 turbine-driven auxiliary feedwater pump and severe weather had been predicted during a portion of this period. The inspector verified that the licensee had evaluated the risk associated with the work which showed no significant increase in core damage frequency. In addition, the work crew was briefed by the control room on contingencies in the event of severe weather.

The inspector observed corrective maintenance and postmaintenance testing on the Unit 1 turbine-driven auxiliary feedwater pump in order to reduce vibration levels on the pump. Vibration levels on the pump were in the alert range per the ASME Boiler and Pressure Vessel Code, Section XI. The licensee believed that there were voids in the grout beneath the common baseplate for the pump and turbine. To correct this, holes were drilled into the baseplate and an epoxy material was injected underneath the plate to fill the voids. The inspector noted that precautions were taken to ensure that the pump and turbine alignment were not affected during this process. The grout required approximately 18 hours to fully cure, during which severe weather was forecast for the area. The licensee was aware of this and stated that the pump would be available and capable of performing its designed function during the cure time, should it be required. Following the cure time, an operability test was performed on the pump in order to obtain new vibration data. Personnel observed station safety precautions while starting the pump and maintained good communications with the control room. After the pump had been started and its temperatures stabilized, the pump and turbine alignment were again verified to be within acceptable tolerances. Vibration data was also obtained and analyzed which showed no appreciable reduction in pump vibration. The pump remained in the alert range.

c. Conclusions

Overall, maintenance and surveillance activities were conducted safely and in accordance with plant procedures. Maintenance personnel were knowledgeable of their procedures.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 2 Containment Spray Pump Bearing Replacement

a. Inspection Scope (62707)

The inspector observed portions of work to replace the inboard and outboard bearings on Unit 2 Containment Spray Pump 2-02 and reviewed the licensee's determination for the cause of excessive wear on the inboard bearing.

b. Observations and Findings

The inspector observed mechanics replacing the inboard and outboard bearings on Unit 2 Containment Spray Pump 2-02. Temperatures on both of these bearings had been running higher than normal, which prompted this maintenance activity. The new

bearings installed increased the bearing clearance from 3 mils to 4 mils. Personnel in the area demonstrated good ALARA and contamination control practices and properly established a Level 3 foreign material exclusion area, when required.

Examination of the old outboard bearing revealed excessive wear on the upper bearing surface. The licensee believed this resulted from misalignment of the pump and motor; however, periodic vibration analysis did not reveal any trend that would indicate bearing degradation or pending failure. The system engineer reviewed past test results, as well as the work history, which indicated a significant amount of work had been performed in 1994. Prior to this work, vibration levels on the pump had been in the alert range per the ASME Boiler and Pressure Vessel Code, Section XI. In order to correct this, the original 4-vane pump impeller was replaced with a 5-vane impeller. Postmaintenance testing showed a reduction in vibration below the alert range; however, during the following quarterly operability test, a marked increase in vibration was observed. The magnitude of the increase remained below the alert range; however, corresponding oil samples indicated increased levels of bearing material (primarily tin and lead). Subsequent tests showed no abnormal vibration levels or elevated bearing temperatures nor did oil analyses indicate increased amounts of bearing material. Engineering concluded that the pump and motor had been misaligned following the impeller replacement, which was evidenced by increased vibrations and the oil sample taken during the following pump test. During that test, the bearing most likely wore into place and no further degradation occurred. An examination of the old bearing showed sufficient bearing surface remained and the licensee concluded that the pump was not inoperable at any time due to this condition.

c. Conclusions

During replacement of the inboard and outboard bearings on Containment Spray Pump 2-02, excessive wear was observed on the inboard bearing. Following bearing replacement, the pump and motor were realigned within allowable tolerances. The inspector concluded that the misalignment had no adverse affect on pump operability.

M8 Miscellaneous Maintenance Issues

M8.1 **(Closed) LER 50-446/99003**: control room HVAC Train A inoperable due to a blown fuse. On April 18, 1999, the Unit 2, Train A control room heating, ventilation, and air conditioning (HVAC) system failed to actuate in the emergency recirculation mode during a surveillance test. Troubleshooting revealed a blown fuse in the Train A HVAC control circuit which was subsequently replaced and the test was completed satisfactorily.

During their investigation, the licensee determined that a pair of leads had been landed incorrectly in the HVAC control circuit during restoration from a previous surveillance test on April 13, 1999 while Unit 2 was in Mode 5. This established a current path through the actuation relays in the HVAC control circuit which resulted in the relays cycling for approximately ten minutes, until the maintenance error was corrected. The licensee was unable to determine if this was the cause of the blown fuse; however, it

was considered to be a contributing factor.

On April 17, 1999, the licensee shifted Unit 2 from Mode 5 to Mode 4 which required the system to be operable per Technical Specification 3.3.2. The blown fuse was discovered and replaced on April 18, 1999, and system operability was verified prior to expiration of the 48 hour allowed outage time. The requirements of Technical Specification 3.0.4 were not applicable since the required action statement for this specification did not involve a plant shutdown. The licensee entered this condition into their corrective action program as Smart Form SMF-1999-001092-00.

M8.2 **(Closed) LER 50-446/00002**: loss of power to Transformer XST1 and engineered safeguards actuation. This event was previously discussed in NRC Inspection Report 50-445(446)/99-18. No violation of regulatory requirements was identified nor were any new issues revealed by the LER.

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551)

In general, engineering support of operations and maintenance were characterized by knowledgeable engineering personnel focused on safe operation of the plant.

E2 Engineering Support of Facilities and Equipment

E2.1 Shared Emergency and Shutdown Electric Systems

a. Inspection Scope (37551, 92903)

On January 19, 2000, the licensee reported to the NRC that the Class 1E electrical distribution design did not meet the required diversity specified in NRC Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants." The licensee is committed to Regulatory Guide 1.81 in Final Safety Analysis Report Section 1A(B). The inspector reviewed plant power supply and relay drawings to ascertain if the licensee's operability determination was appropriate and evaluated the licensee's immediate corrective actions.

b. Observations and Findings

Smart Form 1999-102-00 dated January 21, 1999, documented a condition where some relays in the emergency diesel generator systems were powered by the opposite unit. However, each of the affected relays had another relay in parallel with the same function powered from the appropriate unit. Because of this redundant design feature, no loss of safety function would occur on one unit if the opposite unit lost power. These relays were powered from common Busses XEC1-1 or XEC2-1 which, in turn, can be powered by either unit through a manual switch. Part of the resolution of SMF 1999-102-00

involved changing the Final Safety Analysis Report through a licensing document change request and safety evaluation. Prior to finalizing the Final Safety Analysis Report change, an engineering peer review was conducted and, during that review, the licensee found that the original problem was more generic in nature.

On January 19, 2000, the licensee concluded that the issue satisfied the 1-hour nonemergency report criteria specified in 10 CFR 50.72(b)(1)(ii)(b) and contacted the NRC stating that they were not in compliance with the provisions of Revision 1 to Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants." The licensee is committed to Regulatory Guide 1.81 in Final Safety Analysis Report Section 1A(B). Specifically, the licensee determined that a number of unit specific loads were powered by shared busses. Smart Form 2000-142-00 was initiated and engineering recommended that operations power Panel XEC1-1 from Unit 2 rather than its normal alignment to Unit 1, and power Panel XEC2-1 from Unit 1 rather than its normal alignment to Unit 2. This alignment ensured that Unit 2 sequencer relays were powered from Unit 2 and that several Unit 1 auxiliary relays were powered from Unit 1.

After a further review of relay drawings, the licensee determined that it did not matter which unit Panels XEC1-1 and XEC2-1 were aligned to because both panels contained safety-related loads for both Units 1 and 2 and, as such, engineering recommended that operations restore the normal panel alignment. The licensee determined that the plant's as-built configuration maintained the ability to perform their safety functions and, as such, withdrew the report to the NRC on February 17, 2000.

c. Conclusions

The licensee identified an issue where some emergency diesel generator relays were powered from the opposite unit in January 1999. The licensee appropriately wrote a Smart Form and determined that equipment operability was maintained because of the redundant nature of the affected emergency diesel generator relays. The full scope of the shared power source issue was not realized until January 2000, when a peer review was being conducted for a proposed change to the Final Safety Analysis Report. The power sources for Panels XEC1-1 and XEC2-1 were swapped to their alternate alignment as recommended by engineering, but it was later found to be an unnecessary manipulation of the plant because Panels XEC1-1 and XEC2-1 contained safety-related loads for both units. The licensee determined that no loss of safety function would occur if power was lost to either Panel XEC1-1 or XEC2-1. The peer review was conducted at the appropriate time during the corrective action process.

E8 Miscellaneous Engineering Issues

E8.1 **(Closed) Licensee Event Report (LER) 50-445/00001**: Technical Specification Limiting Condition for Operation 3.7.3, feedwater isolation valves and associated bypass valves were exceeded. This event was previously discussed in NRC Inspection Report 50-445(446)/99-18. A Notice of Enforcement Discretion was granted by the NRC regarding this event prior to exceeding the prescribed limiting condition for operation.

No violation of regulatory requirements was identified regarding the root causes necessitating issuance of the notice nor were any new issues revealed by the LER.

E8.2 **(Closed) LER 50-445(446)/99005**: potential common-cause failure identified in the JRAK relief valves due to pressure surges in the primary sampling system. This LER was submitted due to inservice test failures of thermal relief valves on the primary sampling system. The root cause of the test failures was attributed to frequent cycling of the relief valves due to the pressure surges in the sample lines during normal operation, which caused premature wearing of the valve internals and introduced particulates between the valve disc and seat. The relief valves were installed as thermal relief devices for the sample lines between the containment isolation valves, not as system pressure protection devices; therefore, sampling system operability was not affected. In addition, the containment isolation valves on either side of the relief valves are normally closed, remote air-operated valves which also fail closed. Operability of these valves was not challenged by the failed relief valves; therefore, the containment isolation safety function was not challenged. The inspector found that the corrective actions for this condition had not been completed as described in the original LER. The licensee reviewed the report and agreed that the information regarding corrective actions was incomplete due to poor interdepartmental communications. The licensee entered this condition into their corrective action program as Smart Form SMF-2000-000450-00 to identify the cause of the incomplete report and preclude recurrence of this condition. The licensee will also submit a supplement to this report to correct the docket. The inspector reviewed the completed corrective actions and concluded that they were adequate, and further corrective actions were being tracked through the corrective action program under Smart Form SMF-1999-0800-00.

E8.3 **(Closed) LER 50-445(446)/99004**: voluntary report for issues relative to qualification of the platform grating and clip system. The licensee initially reported that some grating platforms inside the plant were outside the plant's design basis due to the use of a friction type grating fastener. From subsequent analyses, the licensee determined that this was not the case and retracted the initial report. The licensee considered that this event might be of generic concern to other facilities and submitted this LER voluntarily. No new issues were revealed in this report.

E8.4 **(Closed) LER 50-445/99006**: steam generator tube plugging due to stress corrosion cracking. This LER was submitted by the licensee per Technical Specification 5.6.10 which required NRC notification of steam generator tube inspections that indicated greater than one percent of the tubes in a given steam generator required plugging. During the seventh Unit 1 refueling outage, a total of 48 tubes in Steam Generator 1-04 indicated stress corrosion cracking and were plugged. An additional 9 tubes in Steam Generator 1-04 were plugged due to loose parts, volumetric indications, and other tube pulls. The Unit 1 steam generators are Westinghouse Model D4 with Inconel 600 u-tubes which are susceptible to stress corrosion cracking. The licensee has performed chemical cleaning of the tube support plates and the tube sheets in the Unit 1 steam generators to remove contaminants and maintains a comprehensive chemistry control program to minimize steam generator tube degradation. The licensee verified that the number of tubes plugged would not affect performance of the steam generators during

the next cycle.

E8.5 **(Closed) Inspection Followup Item 50-445(446)/98-09-04**: borated water leaks. In NRC Inspection Report 50-445(446)/98-09, several small leaks from the spent fuel pool and transfer canal were noted. Two minor leaks were located in the transfer canal as evidenced by tele-tale leakage as follows: (1) Tele-tale 36 was leaking approximately 170 milliliters/minute and (2) Tele-tale 25 was leaking approximately 1 drop/minute. One additional leak was located in the ceiling of the room below the number two spent fuel pool with a leakage of approximately 1 drop/min. The licensee was monitoring these leaks and had developed a corrective action plan to identify and stop the leakage.

E8.6 **(Closed) Temporary Instruction 2515/087, "Evaluation of Instrumentation Necessary to Assess Plant and Environmental Conditions During and Following an Accident" (NRC Regulatory Guide 1.97) - Unit 2**

a. Inspection Scope

The inspectors conducted an inspection of Unit 2 instrumentation necessary to assess plant and environmental conditions following an accident by utilizing NRC Temporary Instruction 2515/087. The full scope of the inspection described in NRC Temporary Instruction 2515/087 was reduced because certain aspects of the licensees design had been evaluated in NRC Inspection Report 50-445(446)/90-15. The specific aspects of the Unit 2 instrumentation necessary to assess plant and environmental conditions following an accident not previously evaluated in NRC Inspection Report 50-445(446)/90-15 included the: (1) verification of environmental and seismic qualification, (2) verification of maintenance and surveillance activities to meet qualification and operability requirements, and (3) walkdown of instruments to verify proper range and labeling. The sample size selected included all of Regulatory Guide Type A, Category 1, instruments and selected Type B and C instruments.

b. Observations and Findings

The inspector found that the Unit 2 instrumentation necessary to assess plant and environmental conditions during and following an accident was environmentally and seismically qualified. Planned maintenance and surveillance activities satisfied the provisions of both the environmental and seismic qualification. Instrument displays reviewed had the proper range and were appropriately labeled.

During the review of environmental qualification packages and planned preventive maintenance, the inspector identified an administrative error associated with improperly maintained records. The licensee appropriately wrote a Smart Form for the issue. The inspector noted that the licensee planned to adopt a more user-friendly environmental qualification maintenance program which would facilitate corrective actions in this area. One commodity clearance issue was identified during a walkdown of the containment level transmitters inside the Unit 2 containment building. The licensee wrote a Smart Form on this issue, concluded that operability was not affected, and placed long-term resolution of the issue in their corrective action program.

c. Conclusions

Unit 2 instrumentation necessary to assess plant and environmental conditions during and following an accident was environmentally and seismically qualified. Planned maintenance and surveillance activities satisfied the provisions of both the environmental and seismic qualification. Instrument displays reviewed had the proper range and were appropriately labeled.

IV. Plant Support

P1 Conduct of Emergency Planning Activities

P1.1 Fire Brigade Drill Performance

a. Inspection Scope (71750)

The inspector observed fire brigade response to a simulated fire in the Unit 1, Train A, diesel generator room during an emergency preparedness drill.

b. Observations and Findings

During a regularly scheduled emergency preparedness drill, a fire was simulated in the Unit 1, Train A, diesel generator. The fire was due to a leaking oil line which was spraying oil onto the engine turbo charger. For the purpose of drill simulation, the plant had lost offsite power and the Train A diesel generator was running and supplying loads on the Train A bus. A failure of the Train B diesel generator had been simulated therefore, it was unavailable. A plant equipment operator was dispatched to investigate and arrived on the scene approximately 8 minutes after the fire had started. The fire alarm was not sounded and the fire brigade not summoned until approximately 15 minutes after the fire began.

Personnel in the area attempted to maintain communications with the control room simulator via radio but were experiencing extreme difficulty due to garbled transmissions. A plant public address station was readily accessible in the area, yet this system was not used.

After the fire brigade arrived on the scene and assessed the situation, the first hose team entered the diesel generator room to attack the fire with water. The inspector noted that the nozzleman entered the room without protective gloves. The team attempted to attack the fire from a position directly in front of the door; however, a drill controller informed them that the fire was not accessible from there and they would have to attack it from the other side of the diesel generator. As the hose team made their way around the diesel generator, they discovered that they did not have an adequate hose length to reach the fire. At this point, they backed away to assess the situation and obtain additional hose when the nozzleman obtained a dry chemical fire extinguisher which he successfully used to extinguish the fire. It took approximately 30 minutes to extinguish the fire. These observations were not discussed by licensee

personnel during the facility debrief conducted immediately following the drill.

c. Conclusions

During an emergency preparedness drill, the fire brigade was called to respond to a simulated fire in the Unit 1, Train A, diesel generator. The fire was extinguished in approximately 30 minutes. Communications between the scene of the fire and the control room simulator were hampered by poor radio reception in the area. Personnel continued to rely on radio communications despite the availability of a plant public address station nearby. Fire brigade members displayed sound decision making by extinguishing the fire with dry chemical agents rather than spraying cold water on the hot diesel turbocharger while the engine was simulated to be running.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

a. Inspection Scope (71750)

The inspectors observed security and safeguards activities during routine tours, at protected area access facilities, and at compensatory posts throughout the inspection period.

b. Observations and Findings

The inspectors conducted tours of security posts in the plant throughout the inspection period. The tours included remote posts, such as those on the roofs of the Unit 1 safeguards building and fuel storage building. In all cases, security officers were alert and cognizant of activities in their area.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of the routine resident inspection to members of the licensee's management team on April 6, 2000. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. R. Alps, Security Manager
R. D., Bird, Nuclear Planning Manager
M. Blevins, President, Nuclear Operations
R. D. Calder, Executive Assistant
T.P. Clouser, Chemistry Manager
J. R. Curtis, Radiation Protection Manager
D. L. Davis, Nuclear Overview Manager
R. Flores, System Engineering Manager
D. A. Goodwin, SMART Team 2 Manager
J. J. Kelley, Vice President, Nuclear Engineering and Support
D. C. Kross, Outage Manager
M. L. Lucas, Maintenance Manager
B. Mays, Engineering Programs Manager
J. Martin, Consulting Engineer
D. M. McAfee, Programs Overview Manager
J. W. Meyer, Engineering Analysis Manager
W. R. Morrison, Operation Support Manager
C. W. Rickgauer, Maintenance Overview Manager
R. A. Smith, STI Maintenance Manager
D. W. Snow, Senior Regulatory Compliance Specialist
M. Sunseri, Nuclear Training Manager
J. A. Taylor, Design Basis Engineering Supervisor
C. L. Terry, Senior Vice President and Principal Nuclear Officer
D. L. Walling, Plant Modification Manager
D. T. Wilder, Radiation and Industrial Safety Manager
D. R. Woodlan, Docket Licensing Manager

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance

IP 92903	Followup - Engineering
IP 92904	Followup - Plant Support
TI2515/087	Evaluation of Instrumentation Necessary to Assess Plant and Environmental Conditions During and Following an Accident

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Closed

50-446/00001	LER	Missed surveillance test for molded case circuit breakers (Section 08.1).
50-446/99003	LER	Control room HVAC Train A inoperable due to a blown fuse (Section M8.1)
50-446/00002	LER	Loss of power to Transformer XST1 and engineered safeguards actuation (Section M8.2)
50-445/00001	LER	Technical Specification Limiting Condition for Operation 3.7.3 feedwater isolation valves and associated bypass valves were exceeded (Section E8.1)
50-445(446)/99005	LER	Potential common-cause failure identified in the JRAK relief valves due to pressure surges in the primary sampling system (Section E8.2)
50-445(446)/99004	LER	Voluntary report for issues relative to qualification of the platform grating and clip system (Section E8.3)
50-445/99006	LER	Steam generator tube plugging due to stress corrosion cracking (Section E8.4)
50-445(446)/98-09-04	IFI	Borated water leaks (Section E8.5)
TI 2515/087	TI	Evaluation of Instrumentation Necessary to Assess Plant and Environmental Conditions During and Following an Accident (NRC Regulatory Guide 1.97) - Unit 2. (Section E8.6)

Discussed

None

LIST OF ACRONYMS USED

CVCS	chemical and volume control system
ESFAS	engineered safety features actuation system
HVAC	heating, ventilation, and air conditioning
IAC	instrument air compressor
LER	licensee event report
NCV	noncited violation