APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-445/92-10 Unit 1 Operating License: NPF-87
50-446/92-10 Unit 2 Construction Permit: CPPR-127
Expiration Date: August 1, 1992

Licensee: TU Electric
Skyway Tower
400 North Olive Street
Lock Box 81
Dallas, Texas 75201

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: March 15 through April 25, 1992

Inspectors: W. B. Jones, Senior Resident Inspector
G. E. Werner, Resident Inspector
C. E. Johnson, Project Engineer
T. Reis, Project Engineer

Reviewed by: [signature] for 5-7-92
L. A. Yandell, Chief, Project Section B Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted March 15 through April 25, 1992 (Report 50-445/92-10)

Areas Inspected: Unannounced resident safety inspection of plant status, followup on previously identified items, licensee event report followup, onsite followup of events, operational safety verification, maintenance observation, and surveillance observation.

Results: No violations or deviations were identified.

Control room operators were fully cognizant of ongoing plant evolutions. The shift turnovers provided a comprehensive review of plant evolutions and planned activities. The operators responded well to radiation monitors loss-of-flow alarms while a containment purge was in progress. Appropriate communications were maintained with plant personnel during surveillance testing. A conditional surveillance test interval was missed due to lack of a formal mechanism to schedule such surveillances and high control room activity (paragraph 5.1). Housekeeping activities were a strength (paragraphs 6 and 8).

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The radiation protection program was properly implemented. Excellent radiation protection practices were observed. Radiation protection technicians were aware of work activities ongoing in the radiation control area (paragraphs 6.1 and 7).

The security program provided for proper control of personnel, packages, and vehicles into the protected area. Security intrusion assessment and detection equipment appeared to be well maintained (paragraph 6.2).

Maintenance work instructions were appropriately implemented. A weakness was identified in the clearance report implementation requirements which permitted equipment to be returned to service prior to the independent verification step being completed. This practice could eventually result in personnel injury or equipment damage (paragraphs 7 and 5.3). In one instance, electrical maintenance personnel exhibited poor electrical safety work practices (paragraph 7.2). Administrative barriers to ensuring proper postmaintenance testing on an emergency diesel generator (EDG) were lost when the corrective maintenance work order did not specify postmaintenance testing and the licensee's schedule had the EDG being returned to service without testing. Operations caught the oversight (paragraph 7.5). An incident involving work on the incorrect valve occurred. Contributing factors to the event appeared to be similarity in valve labeling and lack of a verification step in the work instructions for each discipline indicating the component is the same as the one identified in the work order (paragraph 5.4). An unresolved item was identified for the work status of work request tags hung on plant equipment (paragraph 7.1).

Engineering provided a prompt and detailed analysis which demonstrated that a fuel farm located near safety-related structures was bounded by previous analysis in the Final Safety Analysis Report (paragraph 6.4).

Inspection Conducted March 15 through April 25, 1992 (Report 50-446/92-10)

Areas Inspected: No inspection activities were conducted on Unit 2.

Results: Not applicable.

DETAILS

1. PERSONS CONTACTED

TU ELECTRIC

*O. Bhatty, Site Licensing
*M. R. Blevins, Director of Nuclear Overview
*W. J. Cahill, Group Vice President, Nuclear Engineering and Operations
R. D. Calder, Director, Nuclear Engineering
*R. D. Carver, Assistant Electrical Maintenance Manager
R. Flores, Shift Operations Manager
*J. C. Hicks, Project Manager, Regulatory Support
*J. J. Kelley, Plant Manager
*B. T. Lancaster, Manager, Plant Support
*D. M. McAfee, Manager, Quality Assurance
*J. W. Muffett, Manager of Design Engineering
*S. S. Palmer, Stipulation Manager
*A. B. Scott, Vice President, Nuclear Operations
*J. C. Smith, Administrative Assistant to Plant Manager
W. E. Stone, Electrical Maintenance Supervisor
*C. L. Terry, Chief Engineer
*J. E. Thompson, Site Licensing
J. Walden, Electrical Maintenance Foreman
*R. D. Walker, Manager of Nuclear Licensing

CITIZENS ASSOCIATION FOR SOUND ENERGY (CASE)
O. L. Thero, Consultant

*Present at the exit interview.

In addition to the above personnel, the inspectors held discussions with various operations, engineering, technical support, maintenance, and administrative members of the licensee's staff.

2. PLANT STATUS (71707)

Unit 1 was operated at 100 percent reactor power until March 20, 1992, when reactor power was reduced to approximately 50 percent to allow replacement of both main feedwater pump turbine-to-pump couplings. Replacement of both main feedwater pump couplings was completed on April 3, and reactor power increased to 100 percent. Main Feedwater Pump No. 1, however, continued to exhibit possible coupling alignment problems as indicated by higher than normal bearing temperatures. On April 23, reactor power was ramped down to approximately 50 percent to allow for the realignment of Feedwater Pump No. 1. Reactor power was maintained close to 50 percent for the remainder of the inspection period. As of April 25, Unit 1 had operated for 106 consecutive days.

3. FOLLOWUP ON PREVIOUSLY IDENTIFIED ITEMS (92701)

Containment Fire Protection Header Supports

The inspector had documented a concern in NRC Inspection Report 50-445/91-62; 50-446/91-62 involving the design basis of a 1 1/2-inch fire protection header located in the containment building. The concern was that the fire protection header could fail during a design basis earthquake. The licensee provided documentation from their contractor, EarthQuake Engineering, that bounded the subject piping within a previously analyzed sample of 20 small bore nonsafety-related piping configurations. The analysis demonstrated that the small bore nonsafety-related pipes were not vulnerable to catastrophic failure during a seismic event. This analysis was previously reviewed and accepted by an inspector. This review is documented in NRC Inspection Report 50-445/90-03; 50-446/90-03. The inspector concluded that the licensee had appropriately resolved the concern with the fire protection header.

4. ONSITE FOLLOWUP OF WRITTEN REPORTS OF NONROUTINE EVENTS (92700)

The inspector reviewed the below listed licensee event report (LER) to determine whether corrective actions were adequate and whether response to the event was adequate and met regulatory requirements, license conditions, and commitments.

(Closed) LER 90-024-00 and Revision 1: "Operation Prohibited by Technical Specifications"

LER 90-024 reported the licensee's failure to satisfy the requirements of Technical Specifications (TS) 4.6.1.7.2. This TS required that the containment purge and hydrogen purge isolation valves be tested on a staggered basis. The licensee identified that the Managed Maintenance Computer Program surveillance scheduling system and the individual surveillance work orders did not ensure the tests were conducted on a staggered basis. The licensee concluded that personnel error led to the omission of the staggered test-basis requirement in both the automated scheduling system and the work orders.

The basis for requiring staggered testing was to reduce the probability of a common-mode system failure. The failure to perform the testing on a staggered basis increased the time in which a common-mode failure could have gone undetected. The licensee noted that no common-mode failure existed on the basis that all subject valves passed their leak rate tests.

As a result of their evaluation of this deficiency, the licensee indicated that the TS requirement was not clearly stated. Specifically, the licensee indicated it was not clear whether the intent was to stagger testing of the inboard and outboard valves of each penetration or to stagger testing of the individual penetrations. The licensee opted for the more conservative interpretation, which would stagger testing of the inboard and outboard valves of each penetration. This interpretation, however, required that all penetrations be tested at each subinterval, since the penetration design does not allow individual valve testing.

The licensee subsequently reviewed NRC correspondence dated June 15, 1981, (T. E. Murley to R. J. Mattson) which clearly defines the intent of the staggered test basis for containment ventilation penetrations. The correspondence indicated the intent was to monitor the effect of seasonal weather variations on the resilient seat material. The correspondence indicated that staggered testing of the inlet and outlet penetrations was the appropriate manner to monitor these isolation valves.

Subsequently, the licensee issued Supplement 01 to LER 90-004-00 on February 7, 1991. The licensee indicated in the supplement that they would meet the requirements of TS 4.6.1.7.2 by following the guidance in the NRC memorandum.

The inspector reviewed the licensee's corrective actions, which included a review of all surveillance activities with a staggered test basis to ensure appropriate incorporation into the automated scheduling system, and concluded the corrective actions were comprehensive and satisfactory. This LER is closed.

5. <u>ONSITE EVENT FOLLOWUP (93702)</u>

5.1 <u>Missed Technical Specification Surveillance Test</u>

On April 1, 1992, the inspector was notified by the licensee of a missed TS surveillance test. Emergency Diesel Generator (EDG) 1B had been removed from service for scheduled maintenance. TS 3.8.1.1 required that, with either EDG inoperable, the operability of required A.C. (alternating current) offsite sources be verified within 1 hour and at least once per 8 hours thereafter by performing TS Surveillance Requirement 4.8.1.1.1a.

Surveillance Test Procedure OPT-215A, "Class 1E Electrical Systems Operability," Revision 5, implemented TS Surveillance Requirement 4.8.1.1.1a. On the morning of April 1 it was performed within 1 hour after removing EDG 1B from service but was not reperformed within the following 8 hours. The licensee discovered the deficiency and performed Surveillance Test Procedure OPT-215A approximately 2 hours late.

The licensee initiated Operations Notification and Evaluation (ONE) Form 92-316 to document the TS violation. The TS Limiting Condition for Operations (LCO) had been properly logged as required by the licensee's procedure. The unit supervisor was aware that Surveillance Test Procedure OPT-215A was required to be performed within 8 hours. In his statement the unit supervisor indicated he did not write down the time the surveillance test procedure should be performed. Subsequently, activity within the control room increased and the surveillance requirement was overlooked.

Subsequent discussions with operations management by the inspector confirmed the supervisor's oversight to be a contributing cause to the event. However, operations management identified a principle root cause as a failure to provide a formal tracking mechanism for short-term LCO Action Requirements (LCOAR), other than the LCOAR tracking log. The licensee has implemented an interim special surveillance tracking board which utilizes timers with audible alarms. The inspectors have observed the use of this interim corrective action and it appears to be effective as a short-term corrective action. The licensee's long-term corrective actions will be reviewed as part of the followup to the LER.

5.2 Unit 2 Annunciator Power Supply Transfer

On April 4, 1992, work was performed on Unit 2 annunciator cabinets. A cabinet inverter output fuse blew, causing the annunciator power supply to auto transfer to a bus carrying Unit 1 radiation monitor loads. Unit 1 received loss of flow alarms on the radiation monitors. Operators took prompt action and restored the monitors to service. A containment vent was in progress at the time. The prompt operator action was believed to have prevented an inadvertent engineered safety feature (ESF) actuation. Subsequent investigation by engineering found an ESF actuation containment isolation would not have occurred on the loss of flow. Nonetheless, the prompt operator response is commendable.

Because of concern for the impact that Unit 2 work activities could have on the operating unit, the inspector will review the licensee's corrective action as documented on ONE Form FX 92-327 and other related documents. The review of the corrective actions will be an Inspection Followup Item. (445/9210-01)

5.3 Unplanned Control Room Ventilation Emergency Recirculation Actuation

On April 6, 1992, at approximately 2:10 p.m. (CST), an unplanned ESF actuation of the control room ventilation system occurred. At the time of the event, the plant was in steady state operation at 100 percent reactor power. The control room Radiation Monitor X-RE-5896B had been removed from service earlier the same day to replace the pump inlet filter.

Preventive Maintenance Work Order P920001336 authorized the replacement of X-RE-5896B sample pump inlet filters. The radiation monitor had been removed from service in accordance with System Operating Procedure SOP-706, "Digital Radiation Monitoring System," Revision 2; and Section 5.11, "Disabling Control Room Ventilation Radiation Monitoring Actuations." Clearance Report X-92-0736, Revision 0, isolated the pump. This was accomplished, in part, by closing the inlet and outlet Isolation Valves XRM-007 and XRM-008, respectively. The handswitch for high radiation actuation Block X-HS-5896B was placed in the block position. Following completion of the maintenance activity, the operator removed the clearance. After notifying the unit supervisor that he had restored the valves to their proper lineup, he was authorized to take the handswitch, X-HS-5896B, out of block and start the sample pump.

Radiation Monitor RM-11 indicated the system status was normal; however, approximately 2 minutes later, digital radiation monitor system alarms were received and both control room heating, ventilation, and air-conditioning system trains shifted to the emergency recirculation mode. The licensee determined that this was an ESF actuation. The event was reported to the NRC in accordance with 10 CFR Part 50.72(b)(2)(ii) and -(iv).

The licensee's investigation of this event identified that the pump outlet isolation valve, XRM-008, was actually left in the closed position. This resulted in a loss-of-flow through the radiation monitor. Although the loss-of-flow condition did not directly cause the ESF actuation, the system transient, which ensued, appeared to have caused the high alarm signal.

The inspector noted that the operator had lifted the clearance tag and initialed on the clearance report that Valve XRM-008 was open. At the time the system was restored to operation, the independent verification step had not been performed. Station Administration Manual (STA)-605, "Clearance and Safety Tagging," Revision 10, was reviewed to ascertain when the independent verification step was required to be completed. The manual does not require that the independent verification step be completed prior to returning equipment to service. The licensee iterated that its expectations were that the independent verification step be completed prior to returning the equipment to operation. Although no equipment damage or personnel injury resulted from the clearance implementation error, the inspector identified the failure to perform the independent verification step prior to returning equipment to service, as a clearance implementation weakness.

The inspector will review the licensee's corrective actions during the licensee event report followup.

5.4 Work Activity Performed on Incorrect Valve

On April 8, 1992, a corrective maintenance work activity was incorrectly performed on an outboard containment isolation valve instead of the downstream high energy line break isolation valve. The work activity, which was to rework the valve actuator, proceeded to the point of removing the valve actuator air tubing.

Corrective maintenance Work Order C92-0639, Revision 0, was initiated on December 18, 1991, to rework Steam Generator No. 4 high energy line break Isolation Valve 1-HV-2400A-AO. The valve was a 3-inch air operated globe and is located downstream of outboard containment isolation Valve 1-HV-2400-AO. Valve 1-HV-2400A-AO is located 3-4 feet above Valve 1-HV-2400-AO and required scaffolding to perform maintenance.

The work instructions coordinated work activities for maintenance services, mechanical maintenance and instrumentation and control (I&C) personnel. On February 17, 1992, work start was granted for mechanical maintenance to check the bolts around the operating diaphragm. At the start of the work activity, two mechanical maintenance personnel verified that the component was the same as that specified on the work order. This requirement was met as indicated by their signatures in Step 1 of the work instructions. After retorquing, the leak continued and the work instructions were returned to planning.

On April 8, corrective maintenance Work Order C92-0639, Revision 1, was initiated to rework the actuator. Clearance Report 1-92-0741, Revision 0, was implemented to isolate manual valves upstream and downstream of Valve 1-HV-2400A-AO, to close and isolate the air supply to Valve 1-HV-2400-AO and to close Valve 1-HV-2400A-AO. Work start approval was granted and mechanical maintenance verified the clearance was properly placed. Mechanical services had previously erected scaffolding around Valve 1-HV-2400A-AO to support the work activity.

The inspector noted that Revision 1 of the work instructions did not require mechanical maintenance personnel to again verify that the component was the same as specified in the work order. Secondly, when the work discipline changed as specified in the work instructions, that group was not required to verify the component was the same as specified by the work instruction. The inspector noted that the clearance was accepted by mechanical maintenance for both mechanical maintenance and I&C personnel. Procedure STA-605, "Clearance and Safety Tagging," Revision 10, was reviewed and it was found that the clearance report was implemented and accepted in accordance with the licensee's program.

The work activity then proceeded in accordance with the Work Instructions, Revision 1. Two I&C personnel went to the room containing Valves 1-HV-2400A-AO and 1-HV-2400-AO. Work was initiated on what they believed was Valve 1-HV-2400A-AO. However, because they misunderstood the valve tagging, work activity to remove instrument tubing from Valve 1-HV-2400-AO was performed. The Work Instruction, Step 5, required that the I&C technicians close and document the closure of the air supply valve for Valve 1-HV-2400-AO. One of the I&C technicians stated, in part, that "I determined in my mind that 'A' of AO was part of the tag number and 'O' of AO stood for operator, and since the tag number had just one 'A' in it and the clearance was hung on 1-HV-2400-AO, I determined that this was the correct valve."

Following removal of the air tubing on Valve 1-HV-2400-AO, mechanical maintenance was notified that they could proceed with disassembly of the valve actuator. Mechanical maintenance then identified that the incorrect valve had been worked and ONE Form FX-92-331 was initiated to document the event. This ONE Form was subsequently elevated to a plant incident report. In addition, the work instructions were revised to reinstall the air tubing to Valve 1-HV-2400-AO and TS LCOAR 3.6.3 for Containment Isolation Valve 1-HV-2400-AO being inoperable was entered. The work activity was subsequently completed for Valve 1-HV-2400A-AO.

The inspector verified that the work activity on Valve 1-HV-2400-AO was within the boundaries of the clearance report. In this instance, no appreciable risk was present for personnel injury or equipment damage because of work performed on the wrong valve. The radiation work permit was also appropriate for the radiological conditions found at Valve 1-HV-2400-AO.

On March 17, 1992, Unit 2 personnel were to perform work on Chemical Volume and Control System Valve 2-CS-7048A. However, work was performed on Valve 1-CS-7048A. This event is documented in NRC Inspection Report 50-445/92-08; 50-446/92-08 and is the subject of Violation 446/9208-02 dated April 23, 1992. The licensee's immediate corrective actions included the addition of a verification step for each discipline in the work instructions in which the component is the same as specified in the work instructions, notification to plant personnel that other similar labeling conditions exist, and an engineering review to evaluate similarly labeled equipment. The licensee's corrective action for the March 17 and April 8 events will be reviewed as part of the licensee's response to Violation 446/9208-02.

5.5 Summary of Findings

A control room ESF actuation resulted from the improper restoration of a clearance report. Although the event occurred because of personnel error, a clearance implementation weakness was apparent in that the independent verification step was not required to be completed prior to restoring the equipment to service. This clearance implementation weakness could result in personnel injury or equipment damage.

A surveillance action requirement tracking weakness was identified following the missed A.C. offsite source verification. The licensee had not established a programmatic control for short-term TS LCOARs. Appropriate interim corrective actions were taken until long-term corrective actions are developed.

An inspector followup item was identified for a Unit 2 work activity which directly affected Unit 1 operating radiation monitoring equipment.

An incident was identified by the licensee where corrective maintenance activities were performed on the wrong valve. The licensee was evaluating the corrective actions for this event along with their response to Violation 446/9208-02 for work on a wrong unit valve. Potential contributing factors to the later event were valve labeling similarities and a lack of verification by each maintenance discipline that the correct components were selected.

6. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, to assure that selected activities of the licensee's radiological protection programs were implemented in conformance with plant policies and procedures and in compliance with regulatory requirements, and to inspect the licensee's compliance with the approved physical security plan.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. Through in-plant observations and attendance of the licensee's plan-of-the-day meetings, the inspectors maintained cognizance over plant status and TS action statements in effect.

The following paragraphs provide details of certain areas reviewed during this inspection period.

6.1 Radiation Protection Observations

The inspectors reviewed activities associated with the implementation of the radiological protection program. The review consisted of observing activities requiring radiation work permits, tours of the radiological controlled area, and reviewing activities documented in the radiation protection shift log.

Several activities requiring radiation work permits were observed. In each case, the individuals performing the work were cognizant of the radiation work permit requirements. Radiation protection personnel were cognizant of the scope of each activity. In most cases, the activities were documented in the radiation protection shift log. One instance where an activity was not logged was for surveillance Work Request S92-273, which involved the placement of Heise gauges on the Safety Injection Pump No. 1 suction and discharge lines. The roving radiation protection technician was found to be aware of the work activity and the required radiation protection measures were implemented.

The inspectors noted that there were few potentially contaminated areas within the radiologically controlled areas. Radiation areas were properly posted, potentially contaminated areas were appropriately identified and high radiation doors were closed and locked. The inspectors observed a wet area under potentially contaminated piping. Radiation protection personnel were notified and a radiation protection technician promptly responded to survey and dry the area. The area was determined not to be radiologically contaminated.

6.2 Security Program Implementation

The inspectors observed security access controls at the primary access point. Vehicles entering the protected area were searched prior to entry. A security officer was posted with each vehicle not designated as a licensee designated vehicle. Personnel and packages entering into the protected area were properly surveyed. Security activities were observed from the central alarm station. All perimeter detection aids were statused as operable. The inspector noted that camera clarity was excellent and, at the time, there was very little reliance on compensatory posts.

6.3 Facility Tour

The inspectors conducted routine plant tours through the safeguards, auxiliary, and fuel buildings. Plant housekeeping was found to be very good. Steam leaks within the turbine building were either repaired or appropriately confined. One steam leak was found impinging on an air-operated valve. The licensee was notified and took measures to contain the steam leak.

One observation made was in the safeguards building at approximately the 790-foot elevation, Room 85D (pipe chase). The inspector noted that a white material had precipitated out on some of the stainless steel piping in the room. Discussions with a licensee engineer indicated that the material was calcium from the overhead concrete. The licensee indicated that the material had seeped through small cracks in the overhead concrete. The inspector was informed that this deficiency had been documented in nonconformance reports. The significance of the calcium deposits on the stainless steel piping will be reviewed as an inspection followup item (445/9210-02).

6.4 Impact of Fuel Farm on Safety-Related Structures

During a tour of the owner controlled area, the inspector noted a 95,000 gallon fuel tank farm approximately 1900 feet from Seismic Category I structures which had not been analyzed for impact on the structures. The licensee agreed to perform an analysis to quantify any impact on safety-related structures.

The licensee performed an extensive analysis and concluded that the impact from a worst case explosion in the tank farm was bounded by other accident scenarios identified in the Final Safety Analysis Report, including tornado loading and a gas well explosion. The inspector reviewed Calculation CS-CA-0000-3139 and found the modeling, analysis, and conclusions reached to be acceptable. The design calculations for the fuel building wall (Calculation 1634516-C5[B]-097), the most vulnerable safety-related structure, demonstrates a load rating in excess of 3.0 psi. The worst case pressure pulse created by a blast from the fuel farm would be less than 0.5 psi. The inspector agreed that the impact of the fuel farm on nearby safety-related structures was bounded by previous analysis and that no additional safety concerns existed.

6.5 Startup of the Boron Thermal Regeneration System Following Maintenance

On April 20, 1992, the inspector observed the startup of the boron thermal regeneration system (BTRS) in the dilution mode, following corrective maintenance activities. The BTRS startup was conducted in accordance with System Operating Procedure SOP-106A, "Boron Thermal Regeneration System," Revision 5. The inspector found the evolution was well controlled and interruptions to the reactor operator were minimal. The procedure was appropriately utilized and good communications were maintained with the auxiliary operator assisting in the system startup.

6.6 Nuclear Fuel Integrity

The licensee has identified four or five potential leaking fuel rods since the start of Cycle 2 on December 11, 1991. The suspected fuel rod leaks were identified by radioiodine and xenon levels measured after the reactor reached 100 percent thermal power. Following the January 8, 1992, reactor trip, an iodine (I)-131 spike was observed. In addition, the ratio of I-131/I-133 increased, providing an indication of "open" defects. The reactor coolant system (RCS) activity data indicated that the potential "open" defects were on previously irradiated fuel assemblies. These assemblies were received in 1983. None of these fuel assemblies remain for Units 1 or 2.

The RCS activity levels appeared to stabilize at approximately 8.5 X 10E-3 microcuries/cubic centimeter. Reactor power transients have resulted in the RCS activity levels increasing to greater than 2 X 10E-2 microcuries/cubic centimeter, but then trending back down to a steady state level. TS 3.4.7 limits the RCS Dose Equivalent I-133 to 1 microcurie/gram.

The licensee's Station Administration Manual STA-735, "Nuclear Fuel Integrity Program," Revision 2, identified 1-9 failed rods as Action Level 1. The next action level occurs at 10-150 failed rods. The licensee has initiated the following actions in accordance with failed fuel action Level 1:

- Chemistry has provided increased radiochemistry sampling as necessary for detailed fuel performance monitoring;
- A preliminary determination of the fuel defect size and batch identification has been performed;
- Possible causes of the identified defects have been determined (a more detailed identification may be possible as additional radiochemistry and/or postirradiation fuel inspection results are obtained);
- Corporate and plant management have been notified of the fuel performance evaluation;
- Station nuclear engineering will coordinate with radiation protection for necessary protective measures; and
- The fuel vendor has been provided with a copy of the Comanche Peak Steam Electric Station Unit 1 coolant activity data for their evaluation of fuel performance. Their preliminary assessment of fuel performance concurred with TU Electric's assessment.

The licensee experienced two fuel rod failures during Cycle 1 involving an "A" and "C" fuel assembly. The "A" fuel assembly had rods which exhibited abnormal longitudinal growth. The "C" fuel assembly had a rod where the end cap failed. No known leaking fuel assemblies were returned to the core for Cycle 2. The licensee has indicated that fuel assemblies which contain leaking fuel rods will not be reconstituted and returned to the reactor vessel for Cycle 3. The core will be redesigned to operate without any fuel assemblies which contained leaking fuel rods. The inspector will continue to monitor nuclear fuel reliability during Cycle 2 operation.

6.7 Summary of Findings

The licensee maintained very good housekeeping practices, which included minimizing the potentially contaminated areas. Radiation protection personnel demonstrated cognizance of ongoing work activities within the radiologically controlled area. Security personnel maintained appropriate controls over personnel, packages, and vehicles entering the protected area. Security alarm assessment equipment appeared to be appropriately maintained with little reliance on compensatory posts.

An inspection followup item was identified for calcium deposits on stainless steel piping. An engineering analysis of a fuel farm near safety-related structures was promptly developed by the licensee to analyze for any adverse impact on safety-related structures. No adverse condition was identified.

The control room operators maintained excellent communications with the auxiliary operator during the startup of the BTRS. The actual startup of the system in the dilution mode was very well controlled.

The licensee has experienced four or five fuel rod failures since the start of Cycle 2 operations. The licensee's administrative requirements for monitoring the fuel failures have been well implemented.

7. MONTHLY MAINTENANCE OBSERVATION (62703)

The inspectors observed the status of plant equipment. This included the identification of work items on equipment. In addition, station maintenance activities for the safety-related and nonsafety systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and in conformance with the TS.

7.1 Status of Field Work Requests

The inspectors requested the licensee to verify the status of five work requests that were found on various primary plant components (Work Request Nos. 101420, 103297, 101421, 101433, and 122419). At the close of this inspection period, the status of these work requests was still being reviewed and no resolution of work status could be verified at the end of the inspection period.

In addition, scaffolding was observed to be installed in the vicinity of safety-related equipment under Work Order No. C91-1404, with no apparent ongoing work in progress. The work order was closed October 8, 1991. The inspectors inquired whether the scaffolding should have been removed. This item was also under review at the end of the inspection period. The determination of status of each work request and the scaffolding by the licensee will be an Unresolved Item (445/9210-03).

7.2 Replacement of Isolation Module by Electrical Maintenance

The inspector observed two electrical maintenance technicians remove and replace Isolation Module 1A3 (Work Order C92-3807 and Procedure STA-720). This corrective work activity was performed on April 21, 1992, with the terminal points energized. Communications with the control room were good. While discussing the procedure with the technicians, the inspector noted that the individuals were not aware of and did not comply with all the safety precautions associated with working on energized electrical equipment as stated in TU Electric's "Safety Manual," Section 5.2. The poor work practices included using noninsulated tools, failure to insulate themselves from ground, and wearing of jewelry while working inside the energized cabinet. In addition, the work instructions included no precautionary safety statements regarding energized equipment. These observations were discussed with electrical maintenance management.

7.3 Preventive Maintenance

On March 26, 1992, the inspector observed two I&C technicians perform a portion of a rack calibration check on the Unit 1 Containment Spray Pump No. 3 discharge flow transmitter (Work Order P91-10512 and Procedure INC-4624A). The I&C technicians used good work practices and were very methodical during all calibration activities. No discrepancies were noted during performance of this maintenance procedure.

7.4 Resin Removal and Replacement

The inspectors observed maintenance personnel remove resin from Component Cooling Water Demineralized Tank CPX-CCDMFL-01 and replace it with new resin. Personnel appeared to be knowledgeable of the task to be performed. Radiation protection coverage was also provided. Work Order C920001069 instructions were properly implemented.

7.5 EDG

On April 2, 1992, the inspectors noted the licensee had scheduled maintenance on EDG B, such that the EDG would be returned to operable status prior to performance of postmaintenance testing. The inspector questioned the schedule and the licensee initially responded that it was satisfactory since the planned maintenance did not affect the operability of the EDG.

After further review, the licensee noted that the schedule was in error. Work Order C920002723 which involved the replacement of hydraulic lifter assemblies in the 4R rocker assemblies would have left the EDG in an indeterminate status. Postmaintenance testing was required to be performed following this task. The licensee revised the schedule to require that the EDG operability test (OPT-214A) be performed prior to returning the unit to service.

The inspector reviewed Corrective Maintenance Work Order C920002723 and found that it did not require a postmaintenance test. However, operators during the preparation of the clearance report for the work activity on March 30, 1992, identified the need for a postmaintenance test. The appropriate postmaintenance test was identified on the "Impact Sheet" in accordance with Procedure STA-605, "Clearance and Safety Tagging." The need for the postmaintenance test was not transferred back to the work order. The licensee was confident that the postmaintenance test would have been performed as a result of implementing the clearance report. The inspector characterized the failure to document the postmaintenance test requirement on the work order and the improper scheduling as a loss of administrative barriers to assure the test was performed.

The inspector reviewed Procedure MSM-CO-3339, "Emergency Diesel Engine Subcover Assembly Inspection," associated with the work activity. The procedure was comprehensive and provided lucid instructions to the craft. The inspector noted a minor implementation error: the craftsmen verified on the signoff sheet a step which was neither performed nor required to be performed.

7.6 Summary of Findings

Maintenance work activities were observed to be conducted in accordance with the work instructions. Appropriate radiation protection coverage was provided for tasks within the radiologically controlled area. In one instance, electrical maintenance personnel demonstrated poor work practices with respect to electrical safety. Administrative barriers to assuring an EDG postmaintenance test would be performed were lost on the basis of improper scheduling and failure to specify instructions on the work order. However, the associated "Impact Sheet" for the clearance report did identify the appropriate postmaintenance test. An unresolved item was identified for the status of work requests attached to equipment.

8. SURVEILLANCE OBSERVATION (61726)

The inspectors observed the surveillance testing of safety-related systems and components listed below to verify that the activities were being performed in accordance with the TS. The applicable procedures were reviewed for adequacy, test instrumentation was verified to be in calibration, and test data was reviewed for accuracy and completeness. The inspectors ascertained that any deficiencies identified were properly reviewed and resolved.

The inspectors witnessed portions of the following surveillance test activities:

8.1 Safety Injection Pump Surveillance Observations

The inspector observed the performance of ASME Section XI testing of safety injection Pump No. 1 and associated valves (Work Request S92-273 and Procedure OPT-204A, Section 8.2). Coordination and communication of the procedure was seen as excellent. The inspector verified that proper radiological practices were observed. One minor discrepancy was noted. The inspector observed that the procedure called for a 0-2000 psig pressure gage while in actuality a 0-3000 psig gage was installed. The required accuracy specified by the procedure was met with the installed test gage.

8.2 Diesel Generator Area Temperature Profile Test

On April 16, 1992, the licensee performed Plant Performance Test PPT-TP-92A-06, "DG TEMP Performance," Revision 0. The purpose of the test was to obtain data on a diesel generator room temperature profile with the diesel generator at full load and the room ventilation service out of service. The temperature profile data will be used to analyze the scheduled winter season vent for lock-out as described in CPSES Design Calculation 1-EB-302A-3, "Diesel Generator Fan Lock-out Schedule."

Prior to beginning the test on Diesel Generator "A," the performance test engineers and operators revised the precaution, limitations, and notes established in PPT-TP-92A-06, Section 5. The control room operators established communication with the auxiliary operator and engineer in the diesel generator room and the test was initiated. The data was collected with all four engine vent fans off, and the 6-room dampers closed. The outside ambient temperature was 64°Fahrenheit (F).

The license had established a maximum area temperature limit of 115°F, which would require that the dampers be opened and the fans started. The actual maximum area temperature as measured by Temperature Indicator 1-TI-AM11, after 67 minutes without the ventilation system in operation, was 107°F. TS 3.7.3 restricts the diesel generator area maximum temperature under normal conditions to less than 122°F for greater than 8 hours and less than 131°F during abnormal conditions. The inspector noted that the temperature profile results appeared favorable for supporting the scheduled winter season vent lockout.

8.3 Turbine Driven Auxiliary Feedwater (TDAFW) Pump Operability Test

On April 22, 1992, the licensee performed Surveillance Work Order S92-0895, which implemented surveillance test Procedure OPT-206A, "Auxiliary Feedwater System Operability Test," Revision 5. Specifically, Section 8.1.6 was performed which verified operability of the turbine-driven auxiliary feedwater pump and the associated system check valves as required by TS 4.0.5, "Surveillance Requirements for Inservice Inspection and Testing of ASME Code Class 1, 2 and 3 Components." This surveillance also satisfied the requirement of TS 4.7.1.2.a.2 for verifying that the TDAFW pump develops a differential pressure greater than or equal to 1450 psid at a test flow of greater than or equal to 860 gpm when the secondary steam supply is greater than 832 psig. The requirements of TS 4.7.1.2.a(3) and -(4) were also satisfied for the TDAFW system flow path nonautomatic valves, isolation valves, and flow controllers.

The control room operator provided a briefing to personnel involved with the test. During the briefing, the operator remarked that TDAFW Steam Admission Valves 1HV-2452-1 and -2 may fail their inservice test stroke time requirements. These valves are air operated and fail open on a loss of air pressure. Following the briefing, two auxiliary operators aligned the TDAFW system in accordance with the procedure. The inspector noted that the test equipment was also properly installed and the configuration for installing the instrumentation was documented on the verification sheet (STA-694-2).

The inspector observed the performance of Procedure OPT-206A from the TDAFW pump room. The turbine responded as expected and the governor response provided for a smooth acceleration to operating speed. The stroke times for Valves 1-HV-2452-1 and -2 were obtained from light indication on the main control board. The stroke times were 7.45 and 8.39 seconds, respectively. However, the inservice test requirement was 9-11 seconds. Corrective Work Order C92-4260 was initiated to adjust the stroke time on each steam admission valve.

Valves 1-HV-2452-1 and -2452-2 stroke times were adjusted by making small incremental changes to a needle valve off of each pressure regulator. These valves v[illegible] the rate at which each air-operated actuator depressurized. Each valve was adjusted and the TDAFW pump started. The stroke times were left at 1[illegible] and 10.92 seconds, respectively. These times provided for TDAFW pump operability as established in the TS surveillance requirement and the Technical Requirements Manual.

The inspector noted that the licensee had entered into TS LCOAR 3.7.1.2 for the TDAFW pump being inoperable. This TS LCOAR was initially entered because the TDAFW pump discharge valve was closed as required by the procedure. The TS LCOAR was properly logged on the shift-in-progress surveillance sheet. When the TS LCOAR was carried over into the next shift, it was transferred to the TS LCOAR log and documented as A-92-1-12C. The TS LCOAR was exited at 3:20 a.m. (CST) the following morning when the TDAFW system was returned to service.

The inspector expressed concern about the apparent repeated failure of Valves 1-HV-2452-1 and -2 to meet their inservice stroke times. The licensee had revised the Technical Requirements Manual on April 24, 1991, to increase the initiation signal and function time for steam generator water level low-low signal from less than or equal to 60 seconds to less than or equal to 85 seconds. The response time of the turbine to reach rated pump differential pressure as described for TS Surveillance Requirement 4.7.1.2.a.2 was less than 60 seconds with the valves stroking too rapidly. On the basis of the test results, the inspector did not have an operability concern that the TDAFW would not meet the TS surveillance requirements in accordance with the time established in the Technical Requirements Manual.

The inspector will continue to evaluate the engineering basis for the inservice test values provided for Valves 1-HV-2452-1 and -2 during a subsequent inspection. This is considered an inspection followup item (445/9210-04).

8.4 Summary of Findings

Surveillance activities were performed in accordance with the approved surveillance procedures. The activities were well coordinated and appropriate communications were maintained with the control room. Surveillance test briefings were conducted prior to performance of each test. The engineering basis for the inservice test values provided for the TDAFW steam admission valves is an inspection followup item.

9. SUMMARY OF TRACKING ITEMS

The following items were opened in this inspection report:

- Inspection Followup Item 445/9210-01
- Inspection Followup Item 445/9210-02
- Unresolved Item 445/9210-03
- Inspection Followup Item 445/9210-04

The following item was closed in this inspection report:

- LER 90-024-00, Revision 1

14. EXIT MEETING (30703)

An exit meeting was conducted on April 24, 1992 with the persons identified in paragraph 1 of this report. The licensee did not identify as proprietary any of the materials provided to, or reviewed by, the inspectors during this inspection. During this meeting, the inspectors summarized the scope and findings of the inspection.