ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/95-28
50-446/95-28

Licenses: NPF-87
NPF-89

Licensee: TU Electric
Energy Plaza
1601 Bryan Street, 12th Floor
Dallas, Texas

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

Inspection At: Glen Rose, Texas

Inspection Conducted: October 22 through November 25, 1995

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
H. A. Freeman, Resident Inspector
V. L. Ordaz, Resident Inspector

Approved: WD Johnson 12/21/95
William D. Johnson, Chief, Project Branch B Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced inspection, including plant operations; maintenance; engineering; surveillance observations; plant support; engineering, plant support, and maintenance followup; and review of Licensee Event Reports.

Results (Units 1 and 2):

Plant Operations

- Unit 1 tripped on November 19 due to high steam generator levels following a series of events initiated by a main feedwater pump recirculation valve circuit card failure. The circuit card failure caused the main feedwater pump recirculation valve to fail open resulting in low main feedwater pump suction pressure and a subsequent trip of Main Feedwater Pump 1B. Several equipment failures such as a loss of the 345 kV switchyard west bus, a failure in the steam dump control circuitry, a significant feedwater heater leak, and several steam leaks complicated the event recovery. Circuit card failures continue to be one of the primary causes for plant transients (Sections 2.1 and 5.1.3).

- The inspectors reviewed the Institute for Nuclear Plant Operations report and found that no significant safety issues were identified which would require the allocation of additional NRC resources (Section 3.1).

- Plant startup observations included good command, communications, and control of plant evolutions; very good operator knowledge of plant operating characteristics; appropriate management and quality assurance oversight; and good control of reactor operator trainees. One inspector observation involved a relatively significant operator work around during low power operations. Apparently, due to the potential for low pressure turbine shroud bowing due to uneven heating, the licensee does not typically use steam dumps to maintain reactor coolant system temperature. Rather, operators use numerous line drains, steam generator blowdown, and steam to various auxiliaries to control reactor coolant system temperature. The inspector concluded that the steam dump workaround posed a challenge to the operators, which periodically required the attention of all operators (Section 3.3).

Maintenance

- Maintenance activities observed included the installation of several design modifications. The inspectors found that design modification installation was in accordance with procedures (Section 4.1).

Engineering

- The inspectors found that the equipment performance monitoring program had not been well developed and appeared to lack management attention. The inspectors found that the performance monitoring program equipment list was still in draft form more than two years after program implementation. The inspectors noted that the program lacked expectations on how to implement trending and also lacked the tools necessary to effectively trend the parameters. Additionally, the inspectors noted that the performance monitoring program was not a living program and that it had not been updated as the licensee gained operating history (Section 5.1).

- The inspectors concluded that corrective actions associated with Unit 1, upper feedwater preheater bypass penetration overheating events in 1992 (ONE Form 92-553) were not sufficiently comprehensive to identify and prevent a similar condition discovered by the inspectors on Unit 2 in April 1995. The inspectors noted that inadequate engineering corrective actions and a lack of operations involvement associated with ONE

Form 92-553 contributed to the unrecognized frequent operation of all four of the Unit 2 upper feedwater preheater bypass penetrations outside their design basis since 1993. Licensee engineering calculations confirmed that the initial containment operability determination was acceptable and redefined the design bases to gain additional operating margin (Section 8.1).

Summary of Inspection Findings:

Violation 445/94023-02; 446/94023-02 was closed (Section 6.1).
Violation 445/94023-03; 446/9423-03 was closed (Section 8.2).
Violation 446/94014-02 was closed (Section 8.3).
Inspection Followup Item (IFI) 446/93018-01 was closed (Section 7.1).
IFI 445/93018-02; 446/93018-02 was closed (Section 7.2).
IFI 445/93035-01 was closed (Section 7.3).
Unresolved Item 446/9507-01 was closed (Section 8.1).
Licensee Event Report (LER) 446/93-009 was closed (Section 8.3).
LER 446/94-005 was closed (Section 8.3).
LER 445/94-001 was closed (Section 9.1).
LER 445/94-006 was closed (Section 9.1).
Violation 446/95028-01 was opened (Section 8.1).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

Unit 1 began the inspection period at 100 percent power. On November 19, Unit 1 tripped because of a circuit card failure in the feedwater system. On November 22, Unit 1 restarted and resumed 100 percent power on November 24. The unit remained at approximately 100 percent power until November 25, when the chemistry for all four Unit 1 steam generators went out of specification requiring an administrative reduction in power. The report period ended on November 25, with Unit 1 at approximately 30 percent power.

Unit 2 remained at approximately 100 percent power throughout the inspection period.

2 PROMPT ONSITE RESPONSE TO EVENTS (93702)

2.1 Feedwater Induced Reactor Trip

On November 19, Unit 1 was operating at 100 percent power when a control system failure caused the Train A main feedwater pump recirculation valve to fully open. Both main feedwater pumps automatically accelerated to a limited maximum speed of approximately 5400 revolutions per minute in an attempt to compensate for the reduced flow to the steam generators. Operators began to manually reduce load while an auxiliary operator went to isolate the recirculation valve. The increased total feedwater flow caused main feedwater pump suction pressures to drop. Operators were continuing to reduce load on the main generator when low suction pressure caused Main Feedwater Pump 1B to trip and initiate an automatic turbine runback. Reactor power stabilized momentarily at approximately 700 megawatts electric. The operators had difficulty stabilizing steam generator water levels which reached the Hi-Hi level reactor trip setpoint on Steam Generator 1-1 and consequently, at 5:35 p.m., the reactor tripped.

Following the reactor trip, several failures in balance-of-plant equipment complicated recovery efforts. Following the reactor trip, one of two generator output breakers did not open immediately following a reverse power signal and caused the loss of the 345 kV switchyard west bus due to the bus fault protective circuitry. Following the trip, operators noted that the no-load reference temperature was at 563°F rather than 557°F. Additionally, the steam dumps failed to shut fully when required. Finally, numerous steam leaks and a feedwater heater leak were identified following the trip.

The inspector responded to the site following the reactor trip and verified that the plant was stable in Mode 3, and that safety systems had functioned, as required. The inspector concluded that operator response to the transient was appropriate. The inspector will continue to monitor the licensee's corrective action plans in conjunction with followup of Licensee Event Report 445/95-007.

3 PLANT OPERATIONS (71707, 61726)

The inspectors conducted daily examinations of plant operations. The inspectors' review of control room staffing and access, adherence to procedures, compliance with Technical Specifications, and operator behavior and attentiveness was performed to ascertain if the plant was being operated safely and in accordance with requirements. Logs for shift operations, clearances, and for limiting conditions for operation were reviewed for accuracy and appropriate actions.

The inspectors also reviewed the effectiveness of operations surveillance activities by direct observation in order to ascertain that testing of safety-significant systems and components were being conducted in accordance with Technical Specifications and other regulatory requirements.

3.1 Review of Institute of Nuclear Power Operations (INPO) Report

The inspector reviewed the CPSES INPO evaluation report dated September 27, 1995, and found that no significant safety issues were identified which would require followup by the NRC regional office. INPO's evaluation of CPSES operation was consistent with the most recent NRC perception of licensee performance.

3.2 Plant Tours

Plant tours were conducted in the safeguards buildings, auxiliary building, electrical control building, the emergency diesel generator rooms, the turbine buildings, the fuel storage building, and the service water pump intake structure. General plant cleanliness was improved and very good. The inspector noted that ladders and equipment were typically stored in accordance with procedural requirements. The inspectors observed workers properly utilize personal safety equipment such as safety belts, gloves, steel toe shoes, and eye protection. The inspectors observed that expectations concerning material condition and personnel safety were communicated by plant management and implemented by plant workers.

The inspectors found that auxiliary operators (AOs) were knowledgeable of status of equipment and work being performed within their assigned areas. The inspectors noted that operations management conducted frequent plant tours in an effort to encourage more operator ownership of the plant.

3.3 Unit 1 Startup Following November 19 Trip

The inspectors observed portions of the Unit 1 startup on November 21, which was performed in accordance with Integrated Plant Operations Procedure 002A, "Plant Startup from Hot Standby," Revision 10. The inspector verified that the prerequisites for the plant startup were met and that the operators appropriately noted and adhered to the procedural precautions.

The inspectors noted that control room command, control and communications during rod latching, rod movement and starting the main turbine were appropriately formal and disciplined. Very good procedure adherence and self-verification were noted. Significant management and nuclear overview presence was apparent. A trainee was utilized for the reactor startup and the inspectors noted that positive supervisory control was maintained at all times. The reactor operator training the student vocalized planned actions and challenged the knowledge of the student prior to the specific evolution. For example, prior to pulling rods for the reactor startup, the reactor operator appropriately questioned the student on the indications to be monitored while pulling rods and the indications of a critical reactor.

Portions of the Unit 1 startup observed in the turbine building included the startup of Main Feedwater Pump 1A and main turbine warming. The inspectors noted procedural adherence and very good communications between the control room operators and the auxiliary operators in the field. Supervisory oversight was apparent. Following the Main Feedwater Pump 1A startup and during warming of Main Feedwater Pump 1B, the inspector noted significant waterhammers in the heater drains from High Pressure Feedwater Heater 3A. Waterhammer induced transients were large enough to notably displace the turbine building floor adjacent to the heater drain tank. The licensee was aware of the waterhammers and indicated later that they would focus some engineering resources during the next startup in an effort to ascertain the cause and evaluate potential engineering solutions.

The inspectors observed low power operations and the main turbine startup from the control room. The inspectors noted that operator knowledge of plant response characteristics during low power operations was very good. However, significant operator attention and teamwork were required to maintain stable reactor coolant system temperatures just prior to placing the main turbine in service. The inspector noted that at one point all three reactor operators were focused on maintaining reactor coolant system temperature by placing the following equipment in and out of service: (1) main steam line strainers; (2) main steam to the moisture-separator reheater; (3) high pressure drains for the main turbine, main feedwater pump turbine, and the main steamlines; and (4) adjusting steam generator blowdown. After about 20 minutes, operators placed steam dump controls in the automatic steam pressure mode and the reactor coolant system temperature oscillations immediately stopped.

The licensee indicated that steam dump operation is avoided to minimize low pressure turbine casing temperature differential during startup of a "cold" main turbine. Steam dumps are used by operators prior to main turbine startup only when reactor coolant system temperature stabilization becomes overly difficult. The inspector was concerned that the amount of attention necessary to maintain reactor coolant system temperature stable detracted from the operators' ability to effectively monitor the remainder of the plant and that any additional complications would have made the startup very difficult. The steam dump operator workaround was recognized by the licensee as early as 1991, and a potential design modification has been under consideration.

3.4 Operations Surveillances

The inspectors directly observed the following operations surveillances during this report period:

- Operations Performance Test (OPT) 489B, Revision 3; "Train B Safeguards Slave Relay K603 Actuation Test - Unit 2"

- OPT 214B, Revision 2; "Diesel Generator Operability Test"

The inspectors noted that despite a number of minor distractions and a fairly high noise level in the control room, the pre-evolutionary briefs were thorough, comprehensive, and conducive to interaction between the participants. The licensee took particular care in discussing OPT 214B because it was a new procedure revision being used for the first time. The Unit 2 reactor operator facilitating the pre-evolutionary briefs discussed the precautions and limitations paying particular attention to the new procedure requirements.

During the conduct of the surveillances, the inspectors noted that operations management was appropriately involved and that the operators used self-verification.

3.5 Communications

On November 8, the inspector listened to an RO pass information to an AO via the radio. When the AO acknowledged receipt of the information with "roger," the RO again repeated the information to ensure proper receipt. Once again, the AO did not provide a repeat back. The RO did not attempt proper communication techniques a third time. The inspector questioned the RO regarding the exchange. The RO explained that he normally demanded repeat backs for specific component communications or communications giving orders; however, because this particular communication was for information, he did not demand the same level of communication. The inspector acknowledged the low necessity for obtaining a repeat back for informational communications and concluded that the RO's attempt to obtain one was good. The inspector questioned the shift manager concerning expectation on communication repeat backs. The shift manager stated that he expected two-leg communications (order - repeat back) for all communications including informational communications and that they were in the process of implementing three-leg communications (order - repeat back - acknowledgement). The shift manager stated that he would have the field support manager ensure AOs understood management's expectations concerning repeat backs. The inspector concluded that this was appropriate.

4 MAINTENANCE OBSERVATIONS (62703)

To ensure safe operation of the plant and plant equipment, the inspectors conducted a review of the licensee's safety-significant maintenance activities. This review entailed the visual inspection of plant structures, systems and components, as well as interviewing maintenance personnel, to ensure reliable safe operation of the plant and compliance with regulatory requirements. The maintenance observed during the report period is listed below and inspector observations follow. The inspectors also reviewed the effectiveness of maintenance surveillance activities by direct observation in order to ascertain that testing of safety-significant systems and components were being conducted in accordance with technical specifications and other regulatory requirements.

4.1 Implementation of Design Modifications

The inspector periodically observed the implementation of several significant design modifications as follows:

- Design Modification (DM) 94-004; Installation and testing of new high density fuel racks in Spent Fuel Pool (SFP) X-02
- DM 94-022 and DM 94-023; Instrument air system modifications
- DM 92-071; Installation of redundant uninterruptable power supply heating, ventilation, and air conditioning room coolers
- DM 94-032; Modifications to the alternate access point

The inspectors noted that work area cleanliness and housekeeping were adequately controlled and contributed to very good foreign material control practices. The inspectors verified that tool utilization was consistent with the application and with due regard for personnel and equipment safety. Equipment which required calibration was verified to have the proper controls to ensure calibration was maintained valid (e.g., weld rods were maintained in the proper containers and kept warm prior to use). The inspectors noted management, supervisory, and nuclear overview department presence during all significant activities. Rigging was performed by qualified and knowledgeable personnel with the proper safety focus. The inspectors concluded that the design modification installation was being performed in accordance with station procedures and licensee management expectations with proper oversight.

5 ONSITE ENGINEERING (37551)

The inspectors assessed the effectiveness of the onsite engineering organization in identifying, resolving, and preventing plant problems. This assessment was accomplished through a review of licensee corrective actions, root cause determinations, safety committee involvement, and self-assessment in engineering.

5.1 Performance Monitoring Program

The inspectors reviewed aspects of the licensee's performance monitoring program. Specifically, the inspectors reviewed, "Equipment Performance Monitoring Program," (STA 736) Revision 2, dated July 15, 1993, and the implementation of the program in the feedwater system, in the chemical and volume control system, and in the 7300 card system.

5.1.1 Program

The stated purpose of Procedure STA 736 was to, "establish and implement a methodology for identification of degraded system or component performance and initiate corrective actions." The program noted that the essential parameters currently included in established monitoring programs, e.g., vibration analysis program, thermographic analysis program, motor-operated valve program, should be included in the performance monitoring program equipment list (PMPEL). However, the program noted that the parameter trend need not be duplicated. In essence, the inspectors found that Procedure STA 736 was a program that attempted to tie together all the trending programs.

Specifically, the program stated that the system engineering manager was responsible for the identification of critical systems and equipment to be included in the performance monitoring program and for the identification of the essential parameters for these critical systems. The procedure stated that essential parameters and their respective monitoring frequencies should be included in the PMPEL. The inspectors discovered that as of the end of the inspection period, the PMPEL was still in draft form and was dated September 20, 1993.

The inspectors noted that the scope of the licensee's program appeared to have a primary focus on reliable power generation. For example, the first three criteria for equipment inclusion were based on equipment whose loss could cause significant power transients or loss of generating capability. Criterion 4 required safety systems inclusion if there was a record of frequent maintenance that has caused its actuation. Criterion 5 stated that appropriate auxiliary feedwater system parameters would be monitored and trended to correct problems. The inspectors reviewed the draft PMPEL and noted that it included some safety system parameters including containment spray and component cooling water parameters.

5.1.2 Main Feedwater System

The inspectors reviewed the PMPEL for feedwater system monitoring parameters. The inspectors noted that the PMPEL included feedwater pump turbine bearing temperatures and the temperature when the feedwater isolation valve had to be jacked open as the essential parameters. The PMPEL listed a question mark under the frequency requirement for all feedwater system parameters. The inspectors concluded that this list appeared to lack detail and forethought. Specifically, the list did not include parameters such as vibration analysis, flow verses rpm, or lube oil analysis requirements. The inspectors concluded that the PMPEL showed a lack of development and management attention.

The inspectors reviewed the performance monitoring program implementation with the feedwater system engineer. The inspectors noted that the implemented feedwater program appeared to include all parameters monitored by the plant computer system. Approximately 40 points were printed out and collected by the engineer which were recorded on a weekly basis. The inspectors noted that the data was not plotted and did not include environmental data (such as ambient temperature or service water intake temperatures) or power levels, which could significantly affect the recorded data. The system engineer stated that an experienced engineer would be able to review the data and would be able to note any trends. The inspectors disagreed and concluded that objective evaluations and long-term trends could not be identified without accounting for external influences and organizing the data into a more usable form.

5.1.3 Protection and Surveillance Package (N-16) (7300 System)

The inspectors questioned the 7300 system engineer on system performance monitoring and other efforts to reduce the number of card failures. The inspectors found that the system engineer maintained good records of all circuit card failures for both the Class 1E and non-Class 1E portions of the 7300 system. However, the inspector noted that the potential use of this failure information was very limited due to the nature of the 7300 system cards and that its use appeared to focus on logging failures, not preventing them. For example, the 7300 system cards which fail are typically sent to the vendor for repair. When the vendor receives the failed card, the failed component is replaced and any upgrades not installed in the card are installed automatically by the vendor. Since there are approximately 67 types of cards in the 7300 system, each of which could have as many as 35 upgrades over its lifetime, there could be thousands of possible card types in the warehouse and in the plant at any given time. Additionally, the inspector was told by the system engineer that individual components on cards are not dated, so there is no easy way to tell the age of individual components even though the card may have just come back from the vendor.

The inspector noted that the licensee, in an effort to reduce the number of in-plant "new" card failures, utilized an instrument card hot rack. Cards are stored on this rack energized and calibrated so that the licensee may use cards that are proven to operate prior to installing them in the plant. The inspector concluded that the use of the hot rack was a strength.

The inspector questioned the system engineer on what other 7300 system parameters were trended and found that card failure trending was his primary focus. Some limited thermography trending had been implemented to monitor for fuseholder degradation which appeared very good and focused on identifying degradation prior to failure manifestation. Surveillance failures were trended loosely. Little or no trending was performed on 7300 system power supply ripple and voltage even though there was a history of power supply failures.

5.1.4 Conclusions

The inspectors concluded that the equipment performance monitoring program, as delineated in Procedure STA 736, had not been well developed and appeared to lack management attention as evidenced by a draft version of the PMPEL, more than two years after program implementation. The inspectors noted that the program lacked expectations on how to implement trending and also lacked the tools necessary to effectively trend the parameters. Additionally, the inspectors noted that the program was not being used as a living document and had not been updated as the licensee gained operating history.

6 FOLLOWUP - PLANT OPERATIONS (92901)

6.1 (Closed) Violation 445/94023-02; 446/94023-02: Failure to Follow Operating Procedures for the Emergency Diesel Generator Jacket Water Heater and Reactor Power Ramp Rates

On October 27, 1994, the licensee removed Clearance 2-94-04565 in order to place Emergency Diesel Generator 2-02 in an "auto start" status following a maintenance activity that involved draining the emergency diesel generator jacket water cooling system. The auxiliary operator placed the feeder breaker for the jacket water immersion heater in the "on" position, and placed the jacket water keep warm pump and immersion heater handswitch in the "auto" position. This energized the jacket water immersion heater and the pump with the jacket water cooling system drained, and resulted in damage to the jacket water immersion heater.

The licensee's investigation revealed that the cause of the event was that personnel did not recognize that the Emergency Diesel Generator 2-02 jacket water system was drained. The clearance release was approved, but was not adequate to ensure the proper diesel generator jacket water cooling system lineup specified in System Operating Procedure (SOP) 609B. Also, the inspectors noted that special instructions on the clearance were vague and did not adequately include the intent of Procedure SOP 609B to refill the jacket water immersion heater prior to starting Emergency Diesel Generator 2-02.

The licensee's immediate corrective actions included placing Emergency Diesel Generator 2-02 in the maintenance mode using Procedure SOP 609B, and replacing the damaged heater. This event had occurred in the past, and previous corrective actions included enhancements to Procedure SOP 609B, and an installed sight glass on the jacket water standpipe to aid in determining system status. As a result of this event, the licensee implemented additional corrective actions to preclude further recurrence, which included: (1) reinforcing work control center and clearance processing center expectations, (2) having the note pad section of the clearances identify the planned or expected system/component condition, and (3) restoring the emergency diesel generator using the procedural steps of the system operating procedure. The inspector reviewed the event, and concluded that the licensee's corrective actions were adequate.

Another example associated with the violation included an event on May 14, 1993, in which the Unit 2 reactor power was increased at a rate of 9.3 percent per hour in lieu of the 3 percent per hour specified in Integrated Plant Operating Procedure 003B, "Power Operations."

The inspector discussed the licensee's evaluation of the fuel cladding impact of exceeding the vendor recommended power ramp rates. The inspector agreed with the licensees conclusion that it was unlikely that any fuel leaks would occur as a result of the excessive power ramp on May 14, 1993. The power ramp for this event was outside the vendor recommendations and administrative guidance, but was within the power ramps for which the fuel was designed to operate.

The licensee's actions to prevent further recurrence included requiring a power change briefing prior to power changes, utilizing a power change checklist that defines important parameters to be verified, and reemphasizing management expectations with respect to supervisory oversight and communication.

The inspector independently verified the corrective actions associated with the event, and concluded that they were adequate to minimize the potential for further occurrence.

7 FOLLOWUP - MAINTENANCE (92902)

7.1 (Closed) Inspection Followup Item (IFI) 446/93018-01: Unit 2 Auxiliary Feedwater Pump Maintenance

This followup item involved discrepancies noted in maintenance activities near the Unit 2 turbine-driven auxiliary feedwater pump. The inspector reviewed the archived work order documents related to the work-in-progress tags noted in the followup item. The inspector did not identify any concerns based on this review. Additionally, the inspector reviewed the consequences of using "pipe thread sealant" beyond the expiration date. Based on the listed stock number, the inspector determined that the item in question was actually Neolube, an anti-seize compound composed of graphite and alcohol. The inspector concluded that the use of "expired" anti-seize had no safety consequences.

7.2 (Closed) IFI 445/93018-02; 446/93018-02: Licensee Troubleshooting Activities

This followup item involved the inspector's concerns regarding maintenance department troubleshooting activities. Since this followup item was opened, the inspectors have monitored the licensee's troubleshooting activities as part of the core inspection program and have typically noted appropriate performance. However, in NRC Inspection Report 50-445/95-11; 50-446/95-11, the inspectors identified a lack of formality and thoroughness in the licensee's approach to resolving some potentially significant equipment failures.

At least partially prompted by the weakness identified in NRC Inspection Report 50-445/95-11; 50-446/95-11, the licensee issued guidance concerning the preservation of as-found data and concerning management expectations for troubleshooting activities. The inspector reviewed the licensee's guidance and the maintenance department troubleshooting activities procedure (MDA 111) and concluded that the licensee had an acceptable troubleshooting program. The inspectors will continue to monitor the licensee's troubleshooting activities as part of the normal core inspection program.

7.3 (Closed) IFI 445/93035-01: Control of Gagged Relief Valves

The inspectors reviewed the process by which the licensee maintains control over gagged relief valves and found it to adequately track the installation and removal of relief valve gags with the appropriate engineering review. The inspectors concluded that the licensee's process for controlling gagged relief valves was adequate.

8 FOLLOWUP - ENGINEERING (92903)

8.1 (Closed) Unresolved Item 446/9507-01: Unit 2 Containment Penetration Overheating (ONE Form 95-463)

8.1.1 Adverse Condition Identification

Unresolved Item 446/9507-01 was opened for further evaluation of the long-term impact that sustained temperatures greater than that allowed by design had on the operability of the Unit 2 containment following an inspector-identified condition adverse to quality in the Unit 2 upper feedwater preheater bypass penetrations. While performing a tour of Unit 2 on April 19, the inspectors noted that a portion of auxiliary feedwater piping to Steam Generator 2-02 was hot to the touch. This observation concerned the inspectors because the normally isolated auxiliary feedwater piping was supposed to be at approximately room temperature and the hot piping was an indication of an abnormal condition. In response to questions from the inspectors, the Unit 2 supervisor reported that the upper feedwater preheater bypass pipe penetration temperatures for Penetrations MV-19 (Steam Generator 2-02) and MV-20 (Steam Generator 2-03) were 223°F and 229°F, respectively.

8.1.2 Licensee Immediate Actions

On April 19, the Unit 2 supervisor appropriately initiated ONE Form 95-463 which documented a conversation between station engineering and operations. The ONE Form indicated that containment operability was not affected. On April 20, station engineering directed operations to implement Abnormal Operating Procedure (ABN) 305, "Auxiliary Feedwater System Malfunction," to cool and maintain the penetrations below 200°F, as required by design. On

April 21, in an effort to reduce the need for frequent ABN 305 entry, the licensee performed a containment entry and removed insulation from the piping near the upper feedwater penetrations. Following the last penetration cooldown with auxiliary feedwater after the insulation was removed, upper feedwater penetration temperatures remained below 200°F requiring no further ABN-305 entries.

Other immediate actions implemented by the licensee included a shift order directing upper feedwater penetration temperatures to be monitored by operators once per shift, and directions to utilize auxiliary feedwater to cool the upper penetrations if temperature reached 200°F. On May 2, the licensee implemented changes to computer alarms for both Units 1 and 2 feedwater bypass line upper penetration temperature elements. The "HI" temperature alarm was changed from 295°F to 190°F and the "HI-HI" alarm was changed from 305°F to 295°F.

The inspector concluded that the immediate corrective actions, although somewhat delayed until station engineering told operations to enter ABN 305, were appropriate.

8.1.3 Upper Feedwater Penetration Design

Comanche Peak Final Safety Analysis Report, NRC Safety Evaluation Report (NUREG 0797), and licensee design basis documents indicated that the containment concrete structure was designed in accordance with American Concrete Institute (ACI)/ASME Code (ACI-359) and Regulatory Guides 1.10, 1.15, 1.18, 1.19, and 1.55. Since the upper feedwater preheater bypass piping is in direct contact with the containment penetration concrete, it was designated a "cold penetration" with normal concrete temperature limitations. Item CC-3430 of ACI-359, April 1973, specifies, in part, the following temperature limitations on concrete: (1) temperature shall not exceed 150°F except for local areas which are allowed to have increased temperatures not to exceed 200°F, (2) for short time periods, temperatures shall not exceed 350°F for the interior surface; however, local area temperatures are allowed to reach 650°F for steam and/or water jet in the event of a pipe failure, and (3) higher temperatures than given in items (1) and (2) above, may be allowed in concrete if tests are provided to evaluate the reduction in strength and this reduction is applied to design allowables.

The inspector reviewed licensee concrete Calculation CS-CA-0000-3006, Revision 3, and licensee/Ebasco Calculation CS-CA-0000-3379, Revision 0, for the upper feedwater penetrations. The inspector noted that the Ebasco calculation was performed to evaluate adverse concrete conditions which were previously experienced in Unit 1 upper feedwater preheater bypass penetrations and that the calculation utilized test data to evaluate the effects of cyclic thermal loading of the feedwater bypass line upper penetration. This calculation was based on the conclusion that after 30 thermal cycles the resulting degraded overall concrete compressive strength would be 4,020 psi, 20 psi higher than the design strength of 4,000 psi. The thermal cycle was modeled as a 24 hour period at 320°F with steady state operation below 200°F.

8.1.4 Licensee Evaluation of Adverse Condition

The licensee gathered temperature data from archived plant computer information for both the Unit 1 and Unit 2 upper feedwater preheater bypass penetrations. The licensee's review revealed that Unit 2 Penetration MV-19 had been above 200°F from approximately February 19 to April 20, with only several very short periods below 200°F. The Unit 2 data showed that during at least one temperature transient, fluid temperatures were in excess of 290°F for more than 19 hours. The data also showed that all four of the Unit 2 feedwater bypass line upper penetration temperatures were often above 200°F since 1993. The Unit 1 data indicated that the upper feedwater preheater bypass penetration temperatures were typically within the design limits.

The licensee indicated that the approximate number of thermal cycles on the Unit 2 penetrations ranged from 10 to 14 cycles but the inspector noted that the number of thermal cycles could have exceeded the Ebasco calculation assumptions depending on how the Unit 2 temperature data was interpreted.

The licensee performed further analysis from May through September, in an effort to gain additional margin because the Ebasco calculation assumption of 30 thermal cycles for the entire life of the plant was apparently too limiting. The inspector reviewed Raytheon Calculation 6332-087-01, "Feedwater Bypass Penetration Assessment," for Unit 2, and the licensee's independent review of the Raytheon calculation performed by Stone and Webster Engineering Corporation. The new design basis for the upper feedwater preheater bypass penetrations revised the maximum steady state temperature from 200°F to 320°F. The inspector found the calculations to be accurate and conservative. The independent review was complete and sufficiently independent.

8.1.5 Effectiveness of 1992 Corrective Actions

Unit 1 upper feedwater preheater bypass penetrations experienced similar overheating problems which were resolved in ONE Forms 92-553 and 92-640 which were written in June and July of 1992, respectively. Corrective actions from these ONE Forms included removing pipe insulation adjacent to the penetration and performing engineering evaluations of the concrete stresses from the high temperatures.

The licensee performed a review to determine how excessive upper feedwater preheater bypass penetration temperatures could have gone undetected in Unit 2 for so long in view of the previous problems identified on Unit 1 in 1992. ONE Form 92-553 addressed Unit 1 only per Station Administrative Procedure (STA) 422, Revision 6. This procedure indicated that the Work Control Manager should consider the potential for reporting the ONE Form applicability to Unit 2 by initiating a technical evaluation. The licensee indicated that no technical evaluation was written because the excessive Unit 1 upper feedwater preheater bypass penetration temperatures were attributable to valve leakage that was not yet apparent on Unit 2 because it was still under construction.

The inspectors agreed that it was appropriate for the licensee to not remove the Unit 2 upper feedwater preheater bypass penetration pipe insulation as part of the resolution of ONE Form 92-553. Furthermore, the inspectors concluded that the corrective actions from the 1992, Unit 1 penetration overheating events mitigated further Unit 1 upper feedwater preheater bypass penetration overheating during normal plant operations. However, the inspectors noted that no corrective actions were implemented to monitor either the Unit 1 or Unit 2 penetrations to verify that the corrective actions were effective and to ensure that the penetration design basis (namely, the cyclic thermal loading and maximum allowed temperature assumptions) were met. The inspectors noted that in 1992, plant operating experience indicated that problems existed in the leak tightness of auxiliary feedwater and main feedwater valves and that the potential for Unit 2 penetration overheating could have been anticipated.

8.1.6 Safety Significance and Recent Additional Corrective Actions

The safety significance of the long-term operation of Unit 2 with excessive upper feedwater preheater bypass penetration temperatures was evaluated by the licensee and found to be minor. The significance was minor because the new design basis defined in Raytheon Calculation 6332-087-01, dated September 1, for the Unit 2 upper feedwater preheater bypass penetrations bounded the maximum temperatures found in the archived data. The inspectors agreed with the licensee's evaluation of the archived temperature data and conclusions. However, the inspector noted that operation outside the existing design basis temperature limits from 1993 through April 1995, resulted from inadequate corrective actions to the 1992 over temperature occurrences on Unit 1.

Recent corrective actions taken by the licensee included revisions to Integrated Operating Procedure 003B, "Power Operations," and ABN 305 to incorporate footnotes on the need to monitor upper feedwater preheater bypass penetration temperatures during plant operation and to take action to cool the penetrations in the event they experience high temperatures. Following review and approval of the new design basis defined in Raytheon Calculation 6332-087-01, the licensee implemented additional changes to computer alarms for both Units 1 and 2 feedwater bypass line upper penetration temperature elements. The "HI" temperature alarm was changed from 190°F to 245°F. The inspector concluded that these changes were appropriate.

8.1.7 Conclusion

Licensee engineering calculations redefined the upper feedwater preheater bypass penetration design basis and verified that containment operability was not affected by the excessive penetration temperatures. Inadequate engineering corrective actions and a lack of operations involvement associated with ONE Form 92-553 contributed to the unrecognized frequent operation of all four of the Unit 2 upper feedwater preheater bypass penetrations outside their design basis since 1993.

The inspectors concluded that the corrective actions associated with the Unit 1 1992, upper feedwater preheater bypass penetration overheating events were not sufficiently comprehensive to identify and prevent a similar condition discovered by the inspectors on Unit 2 in April 1995. This is a violation of 10 CFR, Part 50, Appendix B, Item XI, "Corrective Action. (Violation 446/9528-01)

8.2 (Closed) Violation 445/9423-03; 446/9423-03: Containment Sump Trash Racks Failed to Meet Design Requirements

This violation was issued following licensee-identified gaps in Unit 2 containment sump trash racks that were larger than the 0.115 inch mesh size required by design as specified in Final Safety Analysis Report Section 6.2.2. The largest gap was approximately 0.375 by 1.25 inches.

The inspector reviewed the licensee's corrective actions. In their response letter to the violation dated January 23, 1995, the licensee noted that the Unit 2 sump mesh screens were configured per design but that structural gaps existed in the framework and base. The response letter noted that the Unit 2 sumps had been repaired to the original design requirements and committed to repair the Unit 1 sumps during the Spring 1995 refueling outage.

The inspectors verified that the design change had been implemented and that the commitment had been completed during Refueling Outage 1 in Unit 2 and during Refueling Outage 4 in Unit 1.

8.3 (Closed) Violation 446/94014-02; Licensee Event Report (LER) 446/93-009; and LER 446/94-005: Containment Spray System Vibration and High Cycle Fatigue

8.3.1 Issue Summary

Between June 1992 and June 1994, the licensee identified approximately 14 cracks in the Unit 2 containment spray system. The licensee's vibration monitoring program and root cause determination which concluded that the cracks were due to cyclic fatigue (vibration) were completed in October 1992.

8.3.2 Corrective Actions

Initial corrective actions which were implemented in July 1992, were not sufficient to prevent further cyclic fatigue cracking of the containment spray system. Additional corrective actions implemented in during the 1994, Unit 2 refueling outage, and the 1995 Unit 1 refueling outage involved replacement of the four vane containment spray pump impellers with five vane impellers and a number of pipe configuration changes. Vibration analysis following the design modifications indicated a reduction in vibration throughout the containment spray system with few exceptions. The portions of the containment spray system which were found to have unacceptable vibration were modified by the licensee.

8.3.3 Conclusion

The inspectors monitored licensee activities throughout the modification process and found that the corrective actions were implemented in accordance with station procedures and management expectations.

9 ONSITE REVIEW OF LICENSE EVENT REPORTS (92700)

9.1 (Closed) LER 445/94-001 and LER 445/94-006: Turbine Trip/Reactor Trip due to Low Cooling Water Stator Flow Indication

On February 1, 1994, an indicated low flow condition on the primary cooling water to the Unit 1 main generator stator caused a turbine/reactor trip. The licensee indicated that there was no actual loss of stator cooling flow. This event was documented in LER 445/94-001.

The licensee initiated an investigation to determine the cause of the low flow indication, which included several postulated scenarios: (1) an actual low flow condition had occurred; (2) a low flow condition was indicated as a result of some hydraulic anomaly, but an actual low flow condition did not occur; or (3) a low flow condition was not indicated and actuation occurred because of an electronic problem in the flow sensing or signal process circuitry. A direct cause for the indicated low stator primary water flow could not be determined by the licensee. However, the licensee believed that the trip most likely occurred due to a spurious signal in the instrument loop, which generated the turbine trip signal. As a result, the licensee decided to monitor key points for power supply and instrument signal stability. After a 2-month monitoring period, there was no data to show evidence of problems with the power source or instrument signals.

On November 29, 1994, an indicated low flow condition on the primary cooling water to the main generator stator for Unit 1 again caused a turbine/reactor trip. Again, the licensee indicated that there was no actual loss of stator flow. This event was documented in LER 445/94-006.

A definitive cause still could not be determined for the indicated low stator primary water flow indication. Since the logic requires a 2 out of 2 coincidence, there was a lack of electronic problems, and the fact that the transmitters share common sensing lines, the licensee believed that the trip was caused by a sensing line hydraulic anomaly, most likely from gas bubbles. The licensee initiated immediate corrective actions to ensure that the sensing lines had a continuous positive slope to prevent gas accumulation.

The licensee developed a turbine trip reduction task team to review trip reduction modifications recommended by Siemens. The inspector noted that the licensee installed separate sensing lines in the primary water flow stator circuit during Unit 1 Spring 1995 refueling outage and planned further modifications to improve the reliability of the main turbine. The inspector concluded that the immediate corrective actions implemented were appropriate.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

Blevins, M. R., Plant Manager
Buschbaum, D., Technical Compliance Manager
Byrd, R. C., Construction Operations Support Group Manager
Curtis, J. R., Radiation Protection Manager
Daskam, T. J., Senior Nuclear Specialist, Nuclear Overview Department
Davis, D. L., Nuclear Overview Manager
Elmer, L. B., Systems Development Manager
Evans, E. T., Projects Engineering
Finneran, J. C., Civil Engineering Manager
Flores, R., System Engineering Manager
Gilder, T. D., Procurement Engineering
Hope, T. A., Regulatory Compliance Specialist
Jenkins, T., Electrical Maintenance Manager
LaMarca, J. J., Unit 1 Outage Manager
Lancaster, B. T., Plant Support Manager
Lucas, M. L., Maintenance Manager
Madden, F. W., Engineering Overview Manager
McAfee, D. M., Programs Overview Manager
Meyer, J. W., Mechanical Engineering Supervisor
Moore, D. R., Operations Manager
Sawa, S. F., Planning and Scheduling Support Manager
Sly, W. D., Material Coordinator
Smith, S. L., Work Control Center Manager
Snow, D. W., Senior Regulatory Compliance Specialist
Stakes, M. G., Electrical Maintenance
Sunseri, M. W., Maintenance Engineering Manager
Terrel, N. L., Reactor Engineering Supervisor
Terry, C. L., Group Vice President, Nuclear Production
Walker, R. D., Regulatory Affairs Manager
Winters, B. D, Maintenance Engineering

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

2 EXIT MEETING

An exit meeting was conducted on November 30, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as "proprietary" any information provided to, or reviewed by, the inspectors.