UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

January 27, 2003

Mr. C. L. Terry, Senior Vice President
and Principal Nuclear Officer
TXU Energy
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, Texas 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 50-445/02-05; 50-446/02-05

Dear Mr. Terry:

On December 28, 2002, the NRC completed an inspection at your Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed report documents the inspection findings which were discussed on January 7, 2003, with Mr. M. Blevins and other members of your staff.

This inspection examined activities conducted under your licenses as they related to safety and compliance with the Commission’s rules and regulations and with the conditions of your licenses. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

This report documents a finding of very low safety significance (Green), which was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it was entered into your corrective action program, the NRC is treating this finding as a noncited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. One other finding remains unresolved pending the determination of its safety significance using the significance determination process described in NRC Inspection Manual Chapter 0609. The issue has no continuing safety impact, as the problem was promptly corrected. Additionally, licensee-identified violations are listed in Section 4OA7 of this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.790 of the NRC’s "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC’s document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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

Sincerely,

/RA/

William D. Johnson, Chief
Project Branch A
Division of Reactor Projects

Dockets: 50-445
50-446
Licenses: NPF-87
NPF-89

Enclosure:
NRC Inspection Report
50-445/02-05; 50-446/02-05

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	50-445,446/02-05
Licensee:	TXU Generation Company LP
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56, Glen Rose, Texas
Dates:	October 6 through December 28, 2002
Inspectors:	D. B. Allen, Senior Resident Inspector A. A. Sanchez, Resident Inspector C. J. Paulk, Senior Project Engineer, Project Branch A J. M. Keeton, Project Engineer, Project Branch A B. D. Baca, Health Physicist
Approved by:	W. D. Johnson, Chief, Project Branch A Division of Reactor Projects
Attachment:	Supplemental Information

SUMMARY OF FINDINGS

Comanche Peak Steam Electric Station, Units 1 and 2
NRC Inspection Report 50-445/02-05; 50-446/02-05

IR 05000445-02-05; IR 05000446-02-05; TXU Energy; on 10/06/2002-12/28/2002; Comanche Peak Steam Electric Station; Units 1 & 2. Integrated Resident & Regional Report; Refueling and Outage Activities, Event Followup.

The inspection was conducted by resident inspectors, regional project engineers and a regional health physicist. Two Green noncited violations (NCV) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. An inadequate maintenance procedure for testing the lockout relays on the East bus in the 345 kV switchyard resulted in the loss of residual heat removal (RHR) shutdown cooling. The procedure failed to state that actuation of a relay would cause loss of power to both Unit 1 safety-related 6.9 kV buses.

  A self-revealing noncited violation of Technical Specification 5.4.1.a was identified. The finding is greater than minor in that it was associated with the procedure quality attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during a shutdown. The finding is of very low safety significance because reactor cavity level was greater than 23 feet above the reactor vessel flange and residual heat removal cooling was recovered within 8 minutes (Section 4OA3).

Cornerstone: Mitigating Systems

- TBD. An inadequate surveillance procedure for the low temperature overpressure protection (LTOP) temperature channel resulted in Train B residual heat removal system being inoperable. The procedure failed to state that the performance of the surveillance would interlock closed the reactor coolant system (RCS) hot leg to Train B residual heat removal pump suction Valve 1-8702B.

  A self-revealing violation of Technical Specification 5.4.1.a was identified. This finding is greater than minor because it was associated with the mitigating systems attribute of equipment availability and affected the cornerstone objective to ensure the availability of a mitigating system. This violation degraded the safety of a shutdown reactor, and in accordance with Inspection Manual Chapter 0609,

Appendix G, the shutdown safety function of the core heat removal guidelines was not met. Since the finding degraded the ability to recover decay heat removal once it was lost, a Phase 2 analysis is required. This violation is being treated as an unresolved item (URI) until a final characterization of the risk is determined (Section 1R20).

B. Licensee-identified violations

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

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Report Details

Summary of Plant Status

Unit 1 began the report period in Mode 6 during the ninth Refueling Outage 1RF09. The outage ended on November 18, 2002, at 8:16 a.m., when the generator output breakers were closed. The unit achieved approximately 80 percent power on November 21. On November 23, the unit was shutdown and cooled down to Mode 5 to repair Steam Generator 2 atmospheric relief valve block Valve 1-MS-0063. On November 27, the unit was returned to critical operation and achieved full power on November 29. At 2:12 p.m. on November 30, Control Rod G-13 dropped to the full in position and the unit power was reduced, ultimately to 45 percent. On December 4 the unit was shutdown to repair the control rod drive mechanism canopy seal leak that was found while investigating the dropped control rod. On December 13, the unit was returned to critical operation and achieved full power on December 15. The unit operated at essentially 100 percent power for the remainder of the period.

Unit 2 began the report period operating at essentially 100 percent power. On November 7, 2002, generator load dropped to approximately 775 MWe (65 percent reactor power) due to an electrohydraulic control converter failure. The unit returned to full power on November 7 and operated at essentially 100 percent power for the remainder of the report period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed Station Administrative Procedure STA-634, "Extreme Temperature Equipment Protection Program," Revision 3, and Abnormal Conditions Procedure ABN-912, "Cold Weather Preparations/Heat Tracing and Freeze Protection System Malfunction," Revision 6, to determine if these procedures were adequate to ensure that safety-related equipment would remain operable during freezing weather. In addition, on December 3, 2002, the inspectors reviewed the control room log of activities associated with the ABN-912 preparations. The inspectors performed partial walkdowns of the following two systems and areas in each unit to verify the freeze protection measures in ABN-912 had been implemented prior to the onset of freezing conditions.

- Units 1 and 2 emergency diesel generators and associated Rooms 84, 85, 99A and 99B in each unit
- Safety-injection piping and valves in the valve rooms and pipe tunnels adjacent to the refueling water storage tanks for each unit

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors conducted partial walkdowns of the following two risk-significant systems to verify that they were in their proper standby alignment as defined by system operating procedures and system drawings. During the walkdowns, inspectors examined system components for materiel conditions that could degrade system performance. In addition, the inspectors evaluated the effectiveness of the licensee's problem identification and resolution program in resolving issues which could increase event initiation frequency or impact mitigating system availability.

- Unit 2 Train A containment spray in accordance with System Operating Procedure (SOP) SOP-204B, "Containment Spray System," Revision 4, while Train B containment spray was inoperable due to scheduled maintenance on the associated station service water relief valves on November 26, 2002

- Unit 1 Train A RHR system in accordance with SOP-102A, "Residual Heat Removal System," Revision 13, after recovery from shutdown cooling mode of operation on December 12, 2002

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors assessed the licensee's control of transient combustible materials, the materiel condition and lineup of fire detection and suppression systems, and the materiel condition of manual fire equipment and passive fire barriers during tours of the following eight risk-significant areas. The licensee's fire preplans and Fire Hazards Analysis Report were used to identify important plant equipment, fire loading, detection and suppression equipment locations, and planned actions to respond to a fire in each of the plant areas selected. Compensatory measures for degraded equipment were evaluated for effectiveness.

- Fire Area 1CA - Unit 1 containment building on October 31, 2002

- Fire Zone AA21b - auxiliary building 810-foot elevation corridor and common areas on November 25, 2002

- Fire Zone AA21a - auxiliary building 790-foot elevation corridor and common areas on December 3, 2002

- Fire Zone EC051-Unit 1 Train B inverter room on December 6, 2002

- Fire Zone EC050-Unit 2 Train B inverter room on December 6, 2002

- Fire Zone EH053-Unit 1 Train A inverter room on December 6, 2002

- Fire Zone EH052-Unit 2 Train A inverter room on December 6, 2002

- Fire Area 2SD009-Unit 2 Train A switchgear room on December 6, 2002

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed the Final Safety Analysis Report regarding flooding from external sources and Design Basis Document DBD-CS-071, “Probable Maximum Flood (PMF),” Revision 6, to verify that the assumptions made in the external flooding analysis remained valid.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalifications (71111.11)

a. Inspection Scope

The inspectors observed a licensed operator evaluation session in the control room simulator and attended the critique on December 5, 2002. The scenario included: a component cooling water pump trip; condenser vacuum leak which resulted in a manual turbine trip and a reactor trip with two stuck rods; small break loss of coolant accident (LOCA), which then grew into a large break LOCA; and the final actions necessary to transition to containment recirculation. Simulator observations included formality and clarity of communications, group dynamics, the conduct of operations, procedure usage, command and control, and activities associated with the emergency plan.

The inspectors also reviewed training plans and lecture notes concerning plant and industry events, and plant design modifications on December 9, 2002.

b Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors independently verified that Comanche Peak Steam Electric Station (CPSES) personnel properly implemented 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” for two equipment performance problems identified in the following Smart Forms (SMF):

- SMF-2002-003745-00
- SMF-2002-003971-00

The inspectors also independently verified that the corrective actions and responses were appropriate and adequate.

The inspectors reviewed whether the structures, systems, or components (SSCs) were properly characterized in the scope of the Maintenance Rule Program and whether the SSC failure or performance problem was properly characterized. The inspectors assessed the appropriateness of the performance criteria established for the SSCs (if applicable).

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed four selected activities regarding risk evaluations and overall plant configuration control. The inspectors discussed emergent work issues with work control personnel and reviewed the potential risk impact of these activities to verify that the work was adequately planned, controlled, and executed. The activities reviewed were associated with:

- Outage risk assessment and management assessment during Refueling Outage 1RF09

- 1RF09 steam generator nozzle dam removal and manway installation including midloop operation with fuel in the reactor vessel on November 4-5, 2002

- Rescheduled maintenance tagout of Benbrook Breaker CB 8070 in the 345 kV switchyard, Unit 2 solid state protection system surveillance Test OPT-448B and reactor trip breaker response test, and station service water vacuum breaker testing on October 28-30, 2002

- Unit 1 shutdown and outage to repair canopy seal leak between the latch housing and rod travel housing (intermediate canopy seal) and to repair the stationary gripper electromagnet assembly on Control Rod Drive Mechanism G-13 on December 3-13, 2002

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions and Events (71111.14)

a. Inspection Scope

For the six nonroutine events described below, the inspectors reviewed operator logs, plant computer data and the applicable SMF to determine what occurred and how the operators responded, and to determine if the response was in accordance with plant procedures:

- On October 7, 2002, during 345 kV switchyard east bus lockout relay testing, all Unit 1 nonsafety 6.9 kV buses were deenergized, both Unit 1 6.9 kV safety-related buses transferred to their alternate power source, and the Unit 1 Train B emergency diesel generator started due to an inadequate test procedure. SMF-2002-3376-00 documented the event. The inspectors observed control room activities during the shutdown of the diesel generator and the recovery of the nonsafety buses. The observations included plant parameters and equipment performance during the shutdown, licensee's use of procedures, communications, and command and control by the unit supervisor. See Section 4OA3 for a discussion of the event.

- On October 30, 2002, while conducting eddy current testing of Unit 1 Steam Generator 2, water started coming from the tube sheet into both the hot leg and the cold leg bowls from two tubes which had been cut and pulled. The cause was determined to be that operations, believing that these tubes had been plugged, commenced filling the steam generator in accordance with their outage recovery schedule. Inspectors reviewed the immediate actions taken to stop filling the steam generator. Smart Form SMF-2002-003819-00 was generated to enter the event into the corrective action program.

- On November 30, 2002, Unit 1 received several alarms associated with the rod control system while operating at 100 percent power. The operators diagnosed a dropped rod in Shutdown Bank B and reduced power in accordance with Abnormal Procedure ABN-712, “Rod Control System Malfunction,” Revision 9. Subsequently, the dropped rod could not be recovered forcing shutdown of the unit. Smart Form SMF-2000-4167-00 was initiated to enter the event into the corrective action program.

- On December 4, 2002, while investigating the cause of the dropped Control Rod G-13, a leak was identified in the intermediate canopy seal weld on the control rod drive housing for Control Rod G-13. The inspectors reviewed the actions taken to respond to the dropped rod event and comply with the relevant Technical Specifications. The inspectors also reviewed the licensee’s classification and communications of the event to the NRC. The inspectors reviewed the operator logs and other available information to determine what containment leakage monitoring systems might have indicated that the leak existed, independent of the failure of the stationary gripper coil. The inspectors also reviewed the corrective actions planned and implemented to address the failed control rod drive mechanism coil and the leaking canopy seal. Smart Form SMF-2002-4167 documented the dropped rod event and the canopy seal leak.

- On December 10, 2002, while filling and venting a portion of the chemical volume control system following maintenance, the Centrifugal Charging Pump 1-01 was inadvertently run for about 5 minutes with no flow. The operators found that the pump had been gas bound and the system was subsequently vented to return the pump to service. Smart Form SMF-2000-004242-00 was developed to place the event into the corrective action program.

- On December 13, 2002, inspectors observed the Unit 1 reactor operations staff start up the reactor to approximately 2 percent rated thermal power in accordance with Procedure IPO-002A, “Plant Startup From Hot Standby.” The inspectors discussed the estimated critical condition and the actual critical control rod information with the reactor engineers. The inspectors observed the reactor operator staff increase reactor power to 2 percent and transfer steam generator feed flow from the auxiliary feedwater system to the main feedwater pump system. Inspectors observations included formality, clarity of communications, conduct of operations, and procedure usage.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected three operability evaluations conducted by CPSES personnel during the report period involving risk-significant systems or components. The inspectors evaluated the technical adequacy of the licensee's operability determination, determined whether appropriate compensatory measures were implemented, and determined whether or not other pre-existing conditions were considered, as applicable. Additionally, the inspectors evaluated the adequacy of the CPSES problem identification and resolution program as it applied to operability evaluations. Specific operability evaluations reviewed are listed below:

- Quick Turnaround Evaluation QTE-2002-003545-01-00, Evaluation of the operability impact of the service water vacuum breakers failing to open upon a service water pump stop/trip, reviewed October 23, 2002

- Smart Form SMF-2002-3904-00, Nuclear Safety Advisory Letter 02-14, "Steamline Break during Mode 3," reviewed November 7, 2002

- Smart Form SMF-2002-3159-00, Pigeon found inside Orifice CP2-MSORDR-53, in drain line to auxiliary feedwater turbine drain flash tank, and associated Design Modification DM 95-055, reviewed on November 19, 2002

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed the following two operator workarounds to determine if the functional capability of the system or human reliability in responding to an initiating event was affected. The workaround's effect on the operator's ability to implement abnormal or emergency procedures was evaluated.

- Workaround Number 01-0002, Containment spray heat exchanger relief valves on both units were disabled due to lifting during pump starts

- Workaround Number 02-0004, Diesel generator operability was questioned when paralleled to the bus and grid, reference SMF-2002-2566

In addition, compensatory actions for equipment problems, shift orders and caution tags were reviewed to determine that CPSES personnel were identifying operator workarounds at an appropriate threshold and that the equipment problems were identified in the corrective action program.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed or reviewed the results of seven postmaintenance tests for the following maintenance activities:

- Replacement of the Unit 1 component cooling water Valves 1-HV-4573, 1CC-0158 (shell-side inlet and exit of the RHR heat exchanger) and 1-HV-4575, 1CC-0157 (shell-side inlet and exit of the containment spray heat exchanger) on October 25, 2002
- Replacement of the Unit 1 RHR Pump 1-02 on October 22, 2002
- Outage maintenance on the Unit 1 Emergency Diesel Generator 1-02 on October 23, 2002
- Implementation of Modification Change Authorization (MCA) #2001-1458, installation of steel plate stiffeners to the bearing pedestals of the Unit 1 turbine driven auxiliary feedwater pump on November 15, 2002
- Outage maintenance on Unit 1 digital rod position indication, subsequent troubleshooting and rework after failure of initial Operability Test, OPT-117A on November 7, 2002
- Replacement of the motor for Unit 1 Station Service Water Pump 1-01 on October 12, 2002
- Repair of the Unit 1 feedwater isolation Valve 1-HV-2134 and Operability Test OPT-511A, “FW Section XI Isolation Valves,” on December 6, 2002

In each case, the associated work orders and test procedures were reviewed against the attributes in Inspection Procedure 71111, Attachment 19, to determine the scope of the maintenance activity and determine if the testing was adequate to verify equipment operability.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated licensee Unit 1 Refueling Outage 1RF09 activities to ensure that risk was considered when deviating from the outage schedule, the plant configuration was controlled in consideration of facility risk, mitigation strategies were properly implemented, and Technical Specification requirements were implemented to maintain the appropriate defense-in-depth. Specific outage activities reviewed and/or observed by the inspectors include:

- Defense-in-depth and mitigation strategy implementation
- Containment closure capability
- RCS instrumentation including Mansell level instrumentation
- Decay heat removal
- Electrical power sources
- Containment recirculation sump inspection
- Core offload and reload activities
- Reduced inventory and midloop activities, including steam generator manway and nozzle dam installations and removals
- Containment cleanup and inspection
- Unit heatup and startup

b. Findings

Introduction. An unresolved item was identified for failure to have an adequate procedure for calibration of the LTOP temperature channel in accordance with Technical Specification 5.4.1.a which resulted in the Train B RHR system becoming inoperable while Technical Specification 3.9.6 required both trains to be operable.

Description. On October 5, 2002, a self-revealing finding was identified when Train B RHR suction Valve 1-8702B could not be opened during performance of Procedure

INC-7757A, "Analog Channel Operational Test, and Channel Calibration Reactor Coolant System Cold Overpressurization Protection Channel TX-0423," Revision 7. Unit 1 was in Mode 6 during the initial refueling cavity flood up with Train A RHR in shutdown cooling operation and Train B RHR aligned for cavity flood up from the refueling water storage tank. Calibration Procedure INC-7757A tripped the high pressure interlock to Valve 1-8702B, RCS hot Leg 4 to Train B RHR suction, preventing the valve from opening. When the valve could not be opened while realigning Train B RHR to shutdown cooling mode, Train B was declared inoperable and the actions required by Technical Specification 3.9.6 were initiated. Train B RHR was inoperable for approximately 40 minutes.

The cause of the violation was an inadequate procedure for the calibration of temperature Loop TX-0423 in that the procedure did not identify that its performance would cause the Train B RHR system to become inoperable, and therefore was allowed to be performed at an inappropriate time, when both trains of RHR were required.

<u>Analysis</u>. The performance deficiency was an inadequate procedure for calibration of Channel 1-TX-423. The violation was greater than minor in that it was associated with the mitigating systems attribute of equipment availability and affected the cornerstone objective to ensure the availability of a mitigating system. The finding degraded the safety of a shutdown reactor, which requires Inspection Manual Chapter (IMC) 0609, Appendix G to be used. In the checklist for "PWR Cold Shutdown and Refuel Operations RCS Open and Level less than 23 feet," shutdown safety function "Core Heat Removal Guidelines, Equipment (1) both trains of decay heat removal operable," was not met. Since the finding degraded the licensee's ability to recover decay heat removal once it is lost, a Phase 2 analysis was required. This violation is being treated as an unresolved item (URI) until a final characterization of the significance is determined.

<u>Enforcement</u>. Technical Specification 5.4.1.a requires written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 8b requires procedures be maintained for surveillance tests. Procedure INC-7757A was inadequate in that its performance resulted in making Train B RHR inoperable. Because the risk significance of this violation has not yet been determined by a Phase 2 analysis, this failure to maintain an adequate surveillance procedure is being treated as an unresolved item URI 50-445/02-05-01, Failure to Maintain an Adequate LTOP Surveillance Procedure Resulting in Train B RHR Being Inoperable.

1R22 <u>Surveillance Testing (71111.22)</u>

a. <u>Inspection Scope</u>

The inspectors evaluated the adequacy of periodic testing of important nuclear plant equipment including aspects such as preconditioning, the impact of testing during plant operations, and the adequacy of acceptance criteria. Other aspects evaluated included test frequency and test equipment accuracy, range and calibration; procedure adherence; record keeping; the restoration of standby equipment; test failure evaluations; jumper control (if applicable); and the effectiveness of the licensee's problem identification and correction program. The following surveillance test activity was observed by the inspectors:

- Unit 1 low power physics testing in accordance with Procedure NUC-301, "Low Power Physics Testing," after core reload on November 12, 2002

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following four temporary modifications and associated 10 CFR 50.59 reviews. The temporary modifications were verified to be installed in accordance with the plant documentation and procedures. The postinstallation tests were reviewed to confirm the tests were adequate and the test results were satisfactory.

- Installation of canopy seal clamp assembly on the spare control rod drive mechanism nozzle located on Tube 26 in Grid Location M-6 on the Unit 1 reactor vessel head as described in Smart Form SMF-2002-3436 and Final Design Authorization FDA-2002-3436-01

- Installation and calibration of Mansell midloop level indicating system on Unit 1 for Refueling Outage 1RF09 as documented in Work Order 3-01-341043-01

- Installation, calibration, and removal of temporary transmitters for the centrifugal charging pump and safety injection pump performance tests and the emergency core cooling system check valves tests during Refueling Outage 1RF09 as documented in Work Order 3-02-342211-01

- Installation and testing of the alternate power generators for Refueling Outage 1RF09 as documented in Procedure SOP-614A, "Alternate Power Generator Operation," and Design Modification 95-012

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

The emergency exercise scheduled for November 20, 2002, was canceled and replaced with training of emergency response personnel. There were no other opportunities during this inspection period to observe a training scenario which was identified in advance as contributing to the emergency preparedness performance indicator "Drill/Exercise performance."

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector interviewed radiation protection personnel and radiation workers involved in high dose rate, high exposure, and airborne area work activities within the radiologically controlled area for radiation worker and as low as is reasonably achievable (ALARA) practices. The inspector observed high dose work activity involving Unit 1 Steam Generator Eddy Current Testing (RWP 2002-1200) to determine if personnel ALARA practices were within regulatory and procedural compliance.

The following items were reviewed and compared with regulatory requirements to assess the licensee's program to maintain occupational exposures ALARA:

- ALARA program procedures

- Processes used to estimate and track exposures

- Plant collective exposure history for the past 3 years, current exposure trends, and 3-year rolling average dose information

- Eight ALARA prejob, in-progress, and postjob reviews and associated radiation work permit packages which resulted in the highest personnel collective exposures during refueling outages for Unit 1 and Unit 2 (RWP 2002-1200 and RWP 2002-2200, "Steam Generator Secondary Side Activities"; RWP 2002-1215 and RWP 2002-2215, "Scaffolding"; RWP 2002-1400 and RWP 2002-2400, "Steam Generator Eddy Current 1, 2, 3, and 4"; and RWP 2002-1600 and RWP 2002-2600, "Refueling")

- Total effective dose equivalent ALARA evaluations for work activities associated with RWP 2002-1400 and RWP 2002-1600

- Use of administrative and engineering controls to achieve dose reductions
- Selected temporary shielding evaluations (TSR 02-16, “905' Pressurizer Spray Lines,” and TSR 02-17, “204 Reactor Coolant Pump Motor Removal”)
- Individual exposures of selected work groups (health physics, operations, and maintenance services)
- Plant-related source term data, including source term control strategy
- Unit 2 Refueling Outage 2RF06 Radiation Protection ALARA Report
- Nuclear Overview Department Evaluations EVAL-2002-015 and EVAL-2002-029 and ALARA Station Exposure and Radiation Protection Station Performance Reports for the first and second quarters of 2002
- ALARA Committee meeting minutes since the last inspection
- Selected corrective action documentation involving exposure tracking, higher than planned exposure levels, and radiation worker practice deficiencies since the last inspection in this area (SMF-2002 - 0935, 0965, 1050, 1139, 1371, 1854, 2273, 2971, 2972, 3041, 3160, 3257, 3275, 3301, 3494, 3438, 3468, and 3504)

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Mitigating Systems

a. Inspection Scope

The inspector reviewed a sample of performance indicator data submitted by the licensee regarding the mitigating system cornerstone to verify that the licensee’s data was reported in accordance with the requirements of NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2. Reactor operator logs, limiting condition for operation action requirement logs and licensee event reports for June - October, 2002, were reviewed for both units to identify safety system functional failures.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed the Units 1 and 2 RHR maintenance history for the past year to determine if problems were being properly identified, characterized, and entered into the corrective action program for evaluation and resolution. The review involved risk-significant corrective action documents (Smart Forms) that had been issued between December 2001, and December 2002. The inspectors evaluated the SMF and associated work orders to determine that the licensee's problem identification was complete and accurate. That maintenance effectiveness and operability issues were appropriately evaluated and dispositioned. Also, the licensee's efforts in establishing the scope of problems, generic implications, and common cause were evaluated by reviewing pertinent work orders and action plans. The inspectors determined whether the licensee had completed the corrective actions in a timely manner commensurate with risk associated with the issue.

b. Findings and Observations

There were no findings identified associated with the samples; however, the inspectors observed that the licensee had failed to fully implement a corrective action that resulted in a similar problem occurring after the corrective action had been identified.

On March 31, 2002, during the Unit 2 refueling outage, Smart Form SMF-2002-001006 described a conflict in scheduled surveillance activities for the LTOP system. During the surveillance, a bistable is tripped that prevents opening the RHR suction valves on both trains. This delayed placing RHR into service by approximately 2 hours. On June 3, 2002, the licensee issued corrective actions to schedule the surveillance activities to be completed prior to placing RHR into service.

On October 5, 2002, during the Unit 1 refueling outage refueling cavity flood up from midloop, Smart Form SMF-2002-003317 described a similar scheduling conflict in that an LTOP calibration was performed which caused the protected train of RHR to be inoperable. Although the Train B system suction was aligned to reflood the cavity, had it been called upon for the decay heat removal function the suction could not have been realigned by normal means. When the problem was identified, immediate actions were implemented to comply with Technical Specifications. See Section 1R20 for details.

4OA3 Event Followup (71153)

Unit 1 Loss of RHR Shutdown Cooling Due to Lockout Relay Testing in the 345 kV Switchyard

a. Inspection Scope

On October 7, 2002, during 345 kV switchyard east bus lockout relay testing, all Unit 1 nonsafety 6.9 kV buses were de-energized and both Unit 1 6.9 kV safety-related buses transferred to their alternate power source. One of the results of the event was the loss of RHR shutdown cooling for approximately 8 minutes. The inspectors observed control room activities during the recovery portion of the event. The observations included plant parameters and equipment performance during the shutdown, licensee's use of procedures, communications, and command and control by the unit supervisor.

b. Findings

Introduction. A Green self-revealing NCV was identified for failing to have adequate maintenance procedures for testing the lockout relays on the east bus in the 345 kV switchyard in accordance with Technical Specification 5.4.1.a. which resulted in the loss of RHR shutdown cooling.

Description. On October 7, 2002, at 9:36 a.m., a self-revealing finding was identified when the transfer of both Unit 1 safety-related 6.9 kV buses to their alternate power source, Startup Transformer XST1, resulted in a loss of Train B RHR shutdown cooling. The blackout sequencers actuated upon the slow transfer of the safety buses and caused the loss of Train B RHR shutdown cooling. The reactor operators responded to the loss of shutdown cooling by entering ABN-104, "Residual Heat Removal System Malfunction." Train B RHR shutdown cooling was restored at 9:44 a.m.

At the time of the event, Unit 1 was in Mode 6, RCS level greater than 23 feet above the reactor vessel flange, and core offload was in progress. Train B station service water, component cooling water, and RHR (in shutdown cooling mode) were in operation. The Train A RHR system was out of service and not available. The Train B RHR inlet temperature prior to the event was 102°F and when Train B RHR shutdown cooling was restored, the temperature was 108.6°F.

The cause of the event was an inadequate testing procedure used to test lockout relays on the east bus of the 345 kV switchyard. While performing Step 5.4 of the Glen Rose Transmission Procedure, "East Bus Lockout Relay Replacement with East Bus Clearance," Relay 262X-1/E6 was manually operated causing the loss of normal power to both Unit 1 safety-related 6.9 kV buses.

Analysis. The performance deficiency is the use of an inadequate maintenance procedure that resulted in the loss of Train B RHR shutdown cooling. The finding is greater than minor in that it was associated with the procedure quality attribute of the initiating events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during a shutdown.

Applying the Phase 1 screening worksheet, IMC 0609, Appendix A, Attachment 1, the finding is determined to degrade the core heat removal capability of a shutdown reactor. The worksheet directs entry into IMC 0609, Appendix G. The checklist for “PWR Refueling Operation RCS Level Greater Than 23 Feet,” was used. The results from that checklist are that, although the finding did cause the loss of decay heat removal, the finding did not increase the likelihood of a loss of RCS inventory, did not degrade the licensee’s ability to terminate a leak path or add RCS inventory as needed, nor did the finding degrade the licensee’s ability to recover decay heat removal once it was lost. Therefore, the finding was determined to be of very low safety significance (Green).

Enforcement. Technical Specification 5.4.1.a required written procedures to be established, implemented, and maintained covering activities in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 9, requires that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. In this event, inadequate procedures were used to test the 345 kV switchyard east bus lockout relay resulting in the loss of decay heat removal capabilities. Because this failure to establish adequate procedures is of a very low safety significance, and this issue has been placed into the corrective action program (SMF-2002-3376), this violation is being treated as an NCV, in accordance with Section VI.A.1 of the Enforcement Policy: NCV 50-445, 446/02-05-02, Inadequate Procedure to Test Lockout Relay in 345 kV Switchyard Resulted in Loss of Shutdown Cooling.

4OA5 Other Activities

.1 Institute of Nuclear Power Operations (INPO) Final Report of February 2002 Evaluation of TXU Energy’s Comanche Peak Steam Electric Station

The inspector reviewed the INPO Final Report of February 2002, Evaluation of TXU Energy’s Comanche Peak Steam Electric Station, issued on November 6, 2002, for issues of safety significance. No safety-significant issues were identified.

.2 Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01) (Temporary Instruction 2515/145)

This Temporary Instruction provided guidelines to verify compliance with licensee commitments to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." As identified in the Temporary Instruction, Comanche Peak Unit 1 falls within the category of plants that have a low susceptibility to primary water stress corrosion cracking. Consequently, the inspectors used the criteria for evaluating low susceptible plants to conduct this inspection.

a. Inspection Scope

The inspectors performed this performance-based evaluation and assessment to ensure that the NRC had an independent review of the condition of the reactor vessel head and vessel head penetrations. The inspectors assessed the effectiveness of the licensee examinations of the vessel head penetrations. Specifically, the inspectors: (1) attended the prejob briefing, (2) observed a large representative sample of the visual inspection under the upper tier of reflective metallic insulation via video camera delivered by remotely controlled crawler, (3) assessed the condition of the reactor vessel head through the video inspections, (4) assessed the physical difficulties in performing the inspection, including any debris, dirt, boron, or other viewing obstructions, (5) interviewed the examiners, (6) assessed the licensee's ability to distinguish small boron deposits on the reactor head, (7) evaluated the quality and resolution of the examination equipment, (8) reviewed completed records, (9) verified that the licensee documented deficiencies in their corrective action process, and (10) assessed the overall effectiveness of the process used to perform the bare metal visual examination.

The inspectors reviewed the following documents during this inspection:

- NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," dated August 3, 2001

- Comanche Peak Steam Electric Station Response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," TXX-01145, dated August 31, 2001

- NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002

- Comanche Peak Steam Electric Station Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," TXX-02067, dated April 2, 2002

- Comanche Peak Steam Electric Station 30-Day Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," TXX-02103, dated June 3, 2002

- Comanche Peak Steam Electric Station 30-Day Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," TXX-02112, dated June 13, 2002

b. Findings

The inspectors identified no findings of significance. The inspectors concluded that the licensee inspected 100 percent of the general surface area of the reactor vessel head and all penetration tube bases at the reactor vessel head outer surface. The clarity and resolution of the examination equipment, combined with the training, qualification, and procedures, ensured that the examiners could detect small boron deposits. The inspectors have provided the following details of the inspection as required by Temporary Instruction 2515/145, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC BULLETIN 2001-01).”

.1 Examination

The licensee’s examiners were certified in accordance with CPSES procedures to meet ASME Section XI for VT-2 Level II or III.

The examination was performed in accordance with the “Reactor Vessel Head Visual Examination Plan Revision 1,” approved on October 11, 2002.

The examination of the reactor vessel head penetration nozzles was coordinated by a scan plan to ensure full coverage of all penetrations. One individual drove the crawler or moved the articulated video probe according to the scan plan. A second individual verified the location on the scan plan and voice overlaid the video tape with tape counter index value for the nozzle quadrant(s) being reviewed. The third individual independently verified the location on a second scan plan and documented the digital tape counts. The resulting record established a baseline which could be used for comparison for future examinations of the head nozzles. The examiners established an indexing routine that evaluated the vessel head penetration nozzles in quadrants. The inspectors concluded that the scan plan implemented during the examinations ensured that the licensee had inspected all nozzles 360 degrees around the nozzle circumference.

The inspectors verified that the Reactor Vessel Head Visual Examination Plan provided; (1) explicit descriptions of the types of boric acid indications that might be identified, (2) types of indications that shall be investigated further, including boric acid buildup, wastage of carbon steel, and evidence of primary water leakage, (3) appropriate descriptions of the conduct of the examination (i.e., use of the scan plan), and (4) sufficient guidance to satisfy licensee commitments for inspection of the vessel head penetration nozzles and the general surface of the reactor vessel head. The inspectors concluded that the plan, combined with the training, had provided adequate guidance for the examiners to identify, disposition, and resolve deficiencies.

The inspectors reviewed the in-process sheet used to document the inspections. The work package accurately documented the condition of the reactor vessel head and documented the examination of each vessel head penetration. In addition to this documentation, the licensee had videotaped the examination process and had indexed the penetrations.

The inspectors noted that the high resolution video equipment enabled the examiners to easily discern the type of debris (e.g., metal shavings) located at the vessel head penetration area. The inspectors determined that the camera on the crawler provided excellent resolution and allowed Jaeger J-1 images to be easily discerned.

.2 Condition of the reactor vessel head

The examination determined that the reactor vessel head outer surface was generally coated with a thin layer of gray powdery material dust. A light, generally uniform scattering of slightly larger particles was also noted. This coating did not degrade the ability to inspect either the general surface of the head or the base of the penetration tubes and was judged to be a thinner layer than that observed in Unit 2. Preliminary chemical analysis indicated that this dust is predominately representative of common constituents of concrete. A definitive conclusion was reached that the outer surface of the reactor vessel head was sound.

Many penetration tubes exhibited little or no debris at the tube base and were readily judged as acceptable. A larger number of tubes in Unit 1, as compared to Unit 2, had minor accumulations of debris generally toward the uphill side that exhibited a slightly dull glittery appearance. The most significant such deposits were on the order of 1/4 inche in both width radially out from the tube wall and height up the tube wall. These accumulations extended around the tube for a small portion (less than 1/3) of the circumference. The material was clearly short pieces of wire, possibly from a wire wheel and angular metal bits (i.e., chips, shavings, etc.). In no case did these deposits hinder the current or future inspections.

Several tubes exhibited localized accumulations of less metallic appearing debris with radial widths only approximately 1/16 inch wide. Those locations that did appear to be boric acid typically were associated with thin, parallel white lines defining the edges of drip trails running down the tube wall. With no evidence of an active leak from above or below, these deposits were judged to be acceptable. One area around Tubes 68, 56 and 75 exhibited evidence of a spill. This location is generally beneath the head vent valve. The deposits on the head had little thickness and are characterized as individual trails. A thin metal scraping tool was used to verify the thickness of the deposit and the soundness of the metal beneath the deposit. The area around Tube 31 was investigated due to boric acid deposits observed during the previous outage. This condition had been documented and dispositioned as spill related rather than from a leak. During 1RF08, this area had been cleaned with a vacuum and small hose. During this outage the area was found to be generally clean and confirmed to have no evidence of an active leak.

No penetration tube base exhibited indications of a leak from within the annular gap surrounding the tube. There were no instances of debris or other deposits which hindered this examination or would impede future examinations.

Prior to achieving 100 percent power following 1RF09, Unit 1 experienced a dropped control rod. This was determined to be caused by a leak in the Tube 31 intermediate canopy seal weld. The previously identified boric acid deposit observed around this tube during 1RF08 had been the result of a spill and the deposits were confirmed to have been removed prior to this startup. Following the canopy seal weld leak, the observed condition of the head in the general vicinity of Tube 31 included a fluffy boric acid pile and flow area located downhill from Tube 31. These deposits were removed with hot water and scrubbing leaving a largely rust-colored stain area at the base of the tube and in flow streaks running downhill. The area was scratched and scraped to leave randomly oriented marks in the stain to allow easier discernment of future changes. The vessel head was determined to be sound and no local degradation of the head due to boric acid wastage was observed by the licensee.

.3 Capability to identify and characterize small boron deposits

The inspectors concluded that the examiners and equipment used during the examinations could reliably detect and accurately characterize any identified leakage. The inspectors verified that the examiners used equipment with appropriate resolution. During evaluation of the videotapes of the vessel head penetrations, the inspectors found it easy to distinguish the size, type, consistency, and configuration of any identified debris.

.4 Identified materiel deficiencies that required repair

None.

.5 Impediments to effective examinations and/or ALARA issues

The inspectors concluded that, in general, the licensee encountered no impediments to performing a 100 percent bare metal examination of the reactor vessel head and penetration nozzles. The inspectors noted that the licensee used a remotely controlled crawler to examine the vessel head and penetrations under the upper tier of insulation and the crawler and an articulated video probe for the peripheral penetrations under the lower tier of insulation. With these tools the licensee was able to perform an effective examination and minimize the radiation exposure to personnel.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the inspection results to Mr. M. Blevins, Deputy to the Senior Vice President, and other members of licensee management at the conclusion of the inspection on January 7, 2003. The inspectors asked the licensee representatives whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

The inspectors presented the ALARA inspection results to Mr. Lance Terry, Senior Vice President, and other members of licensee management at the conclusion of the inspection on October 18, 2002. The inspectors asked the licensee representatives whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee Identified Violations

The following findings of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600 for being dispositioned as NCVs.

- 10 CFR 20.1904(a) requires each container of licensed material bear a durable, visible label which provides sufficient information to permit individuals handling or using the container, or working in the vicinity of the containers, to take precautions to avoid or minimize exposures. On April 12, 2002, a radioactive sample container was identified with incorrect dose rate information on the label, as described in the licensee's corrective action program Smart Form SMF-2002-1371. Because the finding was not an ALARA planning or work control issue, there was no overexposure or significant potential for an overexposure and the ability to assess dose was not compromised. This violation is not more than of very low safety significance and is being treated as an NCV.

- 10 CFR 20.1501(a) requires, in part, that a licensee make surveys that are reasonable to evaluate the extent of radiation levels. On October 10, 2002, a high radiation area with a radiation level of 250 millirem per hour at 30 centimeters in the Unit 1 lower valve gallery was identified approximately 30 hours after system manipulation of the chemical volume control system demineralizers which had been in service during the initial shutdown crud burst. This occurrence is described in the licensee's corrective action program Smart Form SMF-2002-3504. During this 30 hour period, plant personnel had access to this area. Because the finding was not an ALARA planning or work control issue, there was no overexposure or significant potential for an overexposure and the ability to assess dose was not compromised. This violation is not more than of very low safety significance, and is being treated as an NCV.

- Technical Specification 5.7.1.d states that each individual entering a high radiation area shall possess a radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm set point is reached. On October 10, 2002, an individual entered the Unit 1 Lower Loop 2 Room, which was posted as a high radiation area, and discovered his electronic dosimeter was in the "off" mode, as described in the licensee's corrective action program Smart Form SMF-2002-3257. Because the finding was not an ALARA planning or work control issue, there was no overexposure or significant potential for an overexposure and the ability to assess dose was not compromised. This violation is not more than of very low safety significance and is being treated as an NCV.

ATTACHMENT

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Alldredge, Supervisor, Radiation Protection, ALARA
M. Blevins, Deputy to the Senior Vice President
D. Bozeman, Manager, Emergency Planning
S. Bradley, Supervisor, Radiation Protection, Health Physics
J. Curtis, Manager, Radiation Protection
T. Edwards, Supervisor, Radwaste Operations
S. Ellis, Manager, Operations
R. Flores, Deputy to Vice President of Engineering
J. Kelley, Vice President, Nuclear Engineering and Support
B. Mays, Engineering Programs Manager
D. Moore, Plant Manager
C. Terry, Senior Vice President & Principal Nuclear Officer
R. Walker, Manager, Regulatory Affairs
D. Wilder, Manager, Radiation Protection and Industrial Safety
C. Wilkerson, Senior Engineer, Licensing

NRC

None

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-445/02-05-01	URI	Failure to maintain an adequate LTOP surveillance procedure resulting in Train B RHR being inoperable (Section 1R20)

Opened and Closed

50-445;446/02-05-02	NCV	Inadequate procedure to test lockout relay in 345 kV switchyard resulted in loss of shutdown cooling (Section 4OA3)

Discussed

None

PARTIAL LIST OF DOCUMENTS REVIEWED

Drawings:

NUMBER	TITLE	REVISION
BRP-CS-1-AB-003	Chemical and Volume Control	CP-3
BRP-CS-1-AB-205	Chemical and Volume Control	CP-3
BRP-CS-1-AB-206	Chemical and Volume Control	CP-4
BRP-CS-1-AB-239	Chemical and Volume Control	CP-2
BRP-CS-1-SB-069	Chemical and Volume Control	CP-5
M1-0255	Chemical and Volume Control System Volume Control Tank Loop	CP-22
M1-0255, Sheet 1	Chemical and Volume Control System Charging and Positive Displacement Pump Trains	CP-21

LIST OF ACRONYMS

ALARA	as low as reasonable achievable
CPSES	Comanche Peak Steam Electric Station
IMC	Inspection Manual Chapter
LOCA	loss of coolant accident
LTOP	low temperature overpressure protection
MWe	megawatt electric
NCV	noncited violation
QTE	quick turnaround evaluation
RHR	residual heat removal
RWP	radiation work permit
SDP	significance determination process
SMF	Smart Form

SOP	system operating procedure
SSC	structures, systems, or components