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

May 4, 2006

Mike Blevins, Senior Vice President
and Chief Nuclear Officer
TXU Power
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 05000445/2006002 AND 05000446/2006002

Dear Mr. Blevins:

On March 24, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed integrated inspection report documents the inspection findings which were discussed on March 28, 2006, with you 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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents two self-revealing findings of very low safety significance (Green). Both findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating the findings as noncited violations (NCV) consistent with Section VI.A.1 of the Enforcement Policy. 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 200555-0001; with copies to the Regional Administrator Region VI; 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 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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/

Claude E. Johnson, Chief
Project Branch A
Division of Reactor Projects

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

Enclosure:
NRC Inspection Report 05000445/2006002
and 05000446/2006002 w/attachment:
Supplemental Information

cc w/enclosure:
Fred W. Madden, Director
Regulatory Affairs
TXU Power
P.O. Box 1002
Glen Rose, TX 76043

George L. Edgar, Esq.
Morgan Lewis
1111 Pennsylvania Avenue, NW
Washington, DC 20004

Terry Parks, Chief Inspector
Texas Department of Licensing
and Regulation
Boiler Program
P.O. Box 12157
Austin, TX 78711

The Honorable Walter Maynard
Somervell County Judge
P.O. Box 851
Glen Rose, TX 76043

Richard A. Ratliff, Chief
Bureau of Radiation Control
Texas Department of Health
1100 West 49th Street
Austin, TX 78756-3189

Environmental and Natural
Resources Policy Director
Office of the Governor
P.O. Box 12428
Austin, TX 78711-3189

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
Austin, TX 78711-3326

Susan M. Jablonski
Office of Permitting, Remediation
and Registration
Texas Commission on
Environmental Quality
MC-122
P.O. Box 13087
Austin, TX 78711-3087

Chairperson
Denton Field Office
Chemical and Nuclear Preparedness
and Protection Division
Office of Infrastructure Protection
Preparedness Directorate
Dept. of Homeland Security
Federal Regional Center
800 North Loop 288
Denton, TX 76209-3698

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S. O'Connor, OEDO RIV Coordinator **(SCO)**
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| RIV:RI:DRP/A | SPE:DRP/A | SRI:DRP/A | C:DRS/EB1 | C:DRS/OB | C:DRS/EB2 |
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| AASanchez | TRFarnholtz | DBAllen | JAClark | ATGody | LJSmith |
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| 5/3/06 | 5/1/06 | 5/3/06 | 5/3/06 | 5/3/06 | 5/2/06 |

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**U.S. NUCLEAR REGULATORY COMMISSION**

REGION IV

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|---|---|
| Dockets: | 50-445, 50-446 |
| Licenses: | NPF-87, NPF-89 |
| Report: | 05000445/2006002 and 05000446/2006002 |
| Licensee: | TXU Generation Company LP |
| Facility: | Comanche Peak Steam Electric Station, Units 1 and 2 |
| Location: | FM-56, Glen Rose, Texas |
| Dates: | January 1 through March 24, 2006 |
| Inspectors: | D. Allen, Senior Resident Inspector<br>A. Sanchez, Resident Inspector<br>T. Farnholtz, Senior Project Engineer<br>J. Keeton, Consultant |
| Approved by: | Claude Johnson, Chief, Project Branch A<br>Division of Reactor Projects |
| Attachment: | Supplemental Information |

## SUMMARY OF FINDINGS

IR 05000445/2006002, 05000446/2006002; 01/01/2006-03/24/2006; Comanche Peak Steam Electric Station, Units 1 and 2; Event Followup, Other Activities

This report covered a 3-month period of inspection by two resident inspectors, one regional senior project engineer, and one consultant. Two Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or may 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion VII, "Control of Purchased Material, Equipment, and Services," was identified for failing to assure that purchased equipment conform to the procurement documents. This failure resulted in the installation of a solenoid coil with an alternating current voltage rating of 120 Vac, into a circuit with a direct current voltage rating of 125 Vdc, resulting in the failure of Valve 1-FV-2184. The licensee replaced the solenoid valve, reviewed for extent of condition, and revised the receipt inspection verification plan.

  The violation is more than minor because it is associated with the equipment performance attribute of reliability and affected the mitigating system cornerstone objective to ensure the availability and reliability of the feedwater isolation system to respond to initiating events and prevent undesirable consequences. Using Appendix A of Manual Chapter 0609, the finding screened as very low safety significance in Phase 1 of the SDP because the finding affected the mitigation system cornerstone but did not represent a loss of system safety function, an actual loss of safety function of a single train, nor was potentially risk significant due to seismic, flooding, or severe weather initiating events. The finding has crosscutting aspects of human performance due to the inadequate receipt inspection verification plan and inattention to detail by the receipt inspection personnel (Section 4OA3.2).

- Green. A self-revealing, noncited violation was identified for the failure to implement effective corrective actions to prevent recurrence of a significant condition adverse to quality as described in 10 CFR Part 50, Appendix B, Criterion XVI. During cleaning activities in the station service water intake bay on August 17, 2005, the vacuum hose that was being used to clean the bay floor became lodged in the pump suction housing and caused reduced flow such that the control room operator had to secure the pump. Two very similar events had occurred in 1994 and 1996, and the corrective actions proved inadequate to prevent foreign material from becoming sucked into the pumps. The licensee is currently in the process of modifying and developing procedures and evaluating facility modifications to protect the station service water pumps from foreign material intrusion.

The failure to implement adequate corrective actions for the previous events to prevent foreign material from being sucked into the station service water pumps and causing the pumps to trip or be secured was the performance deficiency. This finding is considered more than minor because it is associated with the equipment performance attribute and affected the mitigating cornerstone objective to ensure the reliability of the station service water system to respond to initiating events and prevent undesirable consequences. The finding was processed through the significance determination process and required a Phase 3 evaluation. The finding was determined to be of very low safety significance based primarily on the short time the performance deficiency actually affected plant equipment. This finding has a crosscutting aspect of problem identification and resolution due to ineffective implementation of corrective action from previous events (Section 4OA5).

B. Licensee Identified Violations

None.

# REPORT DETAILS

Summary of Plant Status

Comanche Peak Steam Electric Station (CPSES), Units 1 and 2, operated at essentially 100 percent power for the entire reporting.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed Abnormal Conditions Procedure ABN-912, “Cold Weather Preparations/Heat Tracing and Freeze Protection System Malfunction,” Revision 7, Section 2, “Cold Weather Preparations,” in the Unit 1 control room in anticipation of colder weather conditions predicted for the weekend of February 10-12, 2006. The inspectors reviewed the Procedure ABN-912 attachments and control room log to verify that plant cooling units and dampers had been aligned for cold weather and that temperatures were being monitored in accordance with the attachments. On February 10, 2006, the inspectors walked down the Units 1 and 2 emergency diesel generators (EDGs) and the common control room heating, ventilation, and air conditioning system for overall readiness for the expected cold weather.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdown (71111.04)

a. Inspection Scope

The inspectors: (1) walked down portions of the below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's corrective action program to ensure problems were being identified and corrected.

- Unit 1 turbine-driven auxiliary feedwater (TDAFW) system in accordance with System Operating Procedure (SOP) SOP-304A, “Auxiliary Feedwater System,” Revision 16, and Operations Testing Procedure (OPT) OPT-206A, "AFW System," Revision 25, while the Train A EDG system was inoperable for scheduled surveillance, on February 1, 2006

- Unit 2, Train A containment spray system in accordance with SOP-204B, “Containment Spray System,” Revision 5, and plant Drawings M2-232 and M2-232, Sheet A, while the Train B containment spray system was inoperable and unavailable for planned pump casing vent valve replacement, seal water cooler replacement, and annual breaker maintenance, on February 14, 2006

- Unit 1, Train A safety injection system in accordance with SOP-201A, “Safety Injection System,” Revision 14, and plant Drawings M1-261 and M1-263 while Train B safety injection system was unavailable for planned lube oil cooler cleaning, on March 22, 2006

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Detailed Semiannual System Walkdown (71111.04S)

a. Inspection Scope

The inspectors conducted a detailed inspection of the Unit 1 Train A station service water system and supporting systems to verify the functional capability of the system as described in the design basis documents. During the walkdowns, inspectors examined system components for correct alignment, for electrical power availability, and for materiel conditions of structural components that could degrade system performance. In addition, the inspectors referenced and used the following documents to verify proper system alignment and setpoints:

- Design Basis Document DBD-ME-233, “Station Service Water System,” Revision 18

- SOP-501A, “Station Service Water System,” Revision 15

- CPSES Drawing M1-0233, “Flow Diagram Station Service Water System,” Revision CP-18

The inspectors also reviewed recent corrective action documents, system health reports, outstanding work requests, and design issues to determine if any of these items could effect the system’s ability to perform as designed. The inspectors interviewed appropriate plant staff regarding the system's maintenance history. A field walkdown was completed during the weeks of February 27 and March 6, 2006.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

## 1R05 Fire Protection (71111.05Q)

### Fire Area Tours

a. Inspection Scope

The inspectors walked down the listed plant areas to assess the materiel condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory materiel condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

- Fire Zone EQ149 - Units 1 and 2 Train B uninterruptible power supply air condition Room 115D on February 2, 2006
- Fire Zone ER150 - Units 1 and 2 Train A uninterruptible power supply air condition Room 115C on February 2, 2006
- Fire Zone 2-SB004 - Unit 2 safeguards corridor and pipe tunnel 790 foot elevation Rooms 59, 64, 70, and 71 on February 9, 2006
- Fire Zone 1-SI012- Unit 1 Train B EDG Rooms 85 and 99A on February 17, 2006
- Fire Zone AA021B - Auxiliary Building 810 foot elevation Rooms 188-193, 202, 203, and 207 on March 7, 2006
- Fire Zone 2-SI012 - Unit 2 Train B EDG Rooms 85 and 99A on March 7, 2006

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

Internal Flood Protection

a. Inspection Scope

The inspectors: (1) reviewed the Updated Safety Analysis Report, the internal flooding analysis, and plant procedures to identify areas that can be affected by internal flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; (3) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (4) walked down the below listed areas to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

C Units 1 and 2, safeguards building 810 foot elevation Train A penetration rooms on February 7-8, 2006

C Units 1 and 2, safeguards building 773 foot elevation Train A areas on February 9-10, 2006

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

The inspectors observed a licensed operator requalification training scenario in the control room simulator on January 30, 2006. The scenario began with a generator core cooling monitor alarm, which resulted in a manual reactor trip and entry into the emergency operating procedures. A loss of offsite power and a failure of the only operable EDG immediately followed the reactor trip. The crew commenced a steam generator depressurization. The operators contacted the Transmission Grid Manager, who was actually in the simulator booth to role play, and coordinated the return of offsite power to the 138 kV switchyard.

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 verified that evaluators and operators were identifying crew performance problems as applicable.

The inspectors also observed a requalification classroom training session prior to this training scenario regarding the loss and recovery of all ac power.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors independently verified that CPSES personnel properly implemented 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” for the following equipment performance problems:

- During the week of February 27, 2006, the inspectors reviewed the corrective actions and performance history of Control Room Ventilation North Intake Radiation Detector X-RE-5895B, which has been in Maintenance Rule (a)(1) status since December 16, 2002, for repeated functional failures due to "Over range hardware problem" alarms caused by the electromagnetic interference from failing sodium vapor lights, as documented in Smart Form (SMF) SMF-2002-004321-00 and SMF-2005-003866-00. During the week of March 6, 2006, the inspectors interviewed the system engineer for the radiation monitoring system and reviewed the performance of the remainder of the system against the maintenance rule performance criteria.

- The common control room heating, ventilation, and air conditioning system, Train A, exceeded the unavailability performance criterion of 12.42 hours per 2 years average unavailability for the emergency filtration function. The Maintenance Rule Expert Review Panel determined that the increase in hours of unavailability were due to a damper modification that will increase the reliability of the system and should not be counted towards the performance criterion. This issue was entered into the corrective action program as SMF-2006-000082-00.

The inspectors reviewed whether the structures, systems, or components (SSCs) that experienced problems 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 where applicable. The inspectors also independently verified that the corrective actions and responses were appropriate and adequate.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed 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:

- Discovery of an intercooler jacket water leak and the declaration of the Unit 1, Train B, EDG to be inoperable during the Train A surveillance work week on January 10, 2006

- A surveillance test run of the Unit 1, Train B, EDG during the Train A surveillance work week on January 11, 2006

- An extended surveillance run and postmaintenance testing of Unit 2 TDAFW Pump 2-01 due to a setup error on the temporary flow instrumentation on January 19, 2006

- Emergent repair of Unit 1 Steam Generator 1-04 Feedwater Split Flow Bypass Valve 1-FV-2184 due to a solenoid failure on February 7, 2006

- Reschedule of 345 kV Comanche Switch line maintenance due to adverse weather conditions on February 20, 2006

- Scheduling of emergent troubleshooting activities for Unit 1 turbine generator protection cabinet alarms to perform sequentially, rather than concurrently, with other planned "heighten level of attention" activities on March 3, 2006

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components;

(2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on Technical Specifications (TSs); (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee had identified and implemented appropriate corrective actions associated with degraded components. The inspectors interviewed appropriate licensee personnel to provide clarity to operability evaluations, as necessary. Specific operability evaluations reviewed are listed below:

- Quick Technical Evaluation (QTE) QTE-2006-000099-01-00, to determine the operability of Unit 1 EDG 1-02 after the discovery of a jacket water leak located in the right bank intercooler, reviewed January 11-13, 2006
- QTE 2005-004694-02-01, to determine Unit 1 operability following manual actions taken during investigation of reactor coolant system leak rate increase following Refueling Outage 1RF11, reviewed the week of February 27, 2006
- SMF-2006-000889-00, to determine the operability of the Unit 1 Station Service Water Pump Train A based on results of examination of heavily rusted seismic supports, reviewed the week of March 6, 2006
- SMF-2006-000857-00, discrepancy in design basis calculation for pipe rupture due to intermediate and terminal end high energy line breaks for Auxiliary Spray Line 2-CS-1-112-2501R-1, reviewed the week of March 6, 2006
- QTE-2006-000972-01-00, Unit 1 TDAFW pump turbine speed control drifted low out of the acceptance band while performing Surveillance Test OPT-206A, reviewed the week of March 13, 2006
- SMF-2006-000423-00, Unit 1 Component Cooling Water Valve 1CC-1058 was replaced with a lower temperature rated valve than what was specified for this valve location, reviewed March 22-23, 2006

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

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

- C Unit 2, Train B centrifugal charging pump testing following a lube oil change and lube oil cooler cleaning, in accordance with Procedure OPT-201B, “Charging System,” Revision 7, reviewed on January 17, 2006

- C Unit 1 Train B Battery Charger BC1ED4-1 testing following replacing circuit boards and other subcomponents, in accordance with Maintenance Section-Electrical Manual (MSE) Procedure MSE-S0-5713, “Class 1E Battery Charger Load Test,” Revision 5, reviewed on January 18, 2006

- C Unit 2 TDAFW Steam Admission Valve 2-HV-2452-2 and TDAFW pump surveillance following a pressure regulator replacement, in accordance with OPT-603B, “TDAFW Accumulator Check Valve Leak Test,” Revision 3, and OPT-206B, “AFW System,” Revision 18, reviewed on January 19, 2006

- C Unit 2 Train B containment spray system following preventive and corrective maintenance that included: seal water cooler replacement, pump casing pump valve replacement, bearing oil cooler cleaning, motor-operated valve inspection, and breaker maintenance, in accordance with OPT-205B, “Containment Spray System,” Revision 13, reviewed on February 15-16, 2006

- C Unit 1 Positive Displacement Pump 1-01 Recirculation Valve 1-8109 following motor operator inspection and repair of damaged wire in accordance with Work Order WO-3-04-301471-01, tested in accordance with SOP-103A, "Chemical and Volume Control System," Revision 16, on February 27, 2006

- C Unit 2 Atmospheric Relief Valves 2-PV-2326 and 2-PV-2328 following installation of disconnect switches per Final Design Authorization FDA-2003-003760, in accordance with OPT-216B, "Remote Shutdown Operability Test," Revision 9, Procedure Change PCN-1, reviewed on March 21, 2006

In each case, the associated work orders and test procedures were reviewed in accordance with the inspection procedure to determine the scope of the maintenance activity and to determine if the testing was adequate to verify equipment operability.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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; system alarm and annunciator functionality; and the effectiveness of the licensee's problem identification and correction program. The following surveillance test activities were observed and/or reviewed by the inspectors:

C Unit 2 main turbine stop and control valve testing in accordance with OPT-217B, "Turbine Overspeed Protection System Test," Revision 8, reviewed on January 7, 2006

C Unit 2 atmospheric relief valve surveillance testing in accordance with OPT-504B, "MS Section XI Valves," Revision 10, reviewed on January 13, 2006

C Unit 1 Containment Sump Drain Isolation Valve 1-HV-5157, outside reactor containment valve stroke time test in accordance with OPT-503A, "CNTMT Section XI ISOL Valves," Revision 13, reviewed on January 23, 2006

• Unit 1 Centrifugal Charging Pump 1-01 inservice test in accordance with OPT-201A, "Charging System," Revision 13, reviewed on January 30-31, 2006

• Unit 1 Centrifugal Charging Pump 1-02 inservice test in accordance with OPT-201A, "Charging System," Revision 13, reviewed on February 13, 2006

• Unit 1, remote shutdown operability test for charging and volume control, in accordance with OPT-216A, "Remote Shutdown Operability Test," Revision 10, reviewed on February 27, 2006

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Initiating Events

a. Inspection Scope

The inspectors reviewed a sample of performance indicator data submitted by the licensee regarding the initiating events cornerstone to verify that the licensee's data was reported in accordance with the requirements of Nuclear Energy Institute NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 3. The sample included data taken from control room operator logs, the SMF database, and licensee event reports for January 2004 through December 2005 for the following performance indicators:

- Units 1 and 2, unplanned scrams per 7,000 critical hours
- Units 1 and 2, unplanned scrams with loss of normal heat removal
- Units 1 and 2, unplanned power changes per 7,000 critical hours

During plant tours, inspectors periodically determined if access to high radiation areas was properly controlled and if potentially unmonitored release pathways were present.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a routine screening of all items entered into the licensee's corrective action program. This review was accomplished by reviewing the licensee's computerized corrective action program database (SMFs), reviewing hard copies of selected SMFs, and attending related meetings such as Plant Event Review Committee meetings.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up - SMF-2004-001177-00, Channel Calibration Was Not Completed within the Required Frequencies for All Components of the Channel

a. Inspection Scope

This issue was selected because TXU assigned it the highest significance level (level 1) within the CPSES corrective action program and performed a root cause analysis. During a review for a proposed change to the Technical Requirements Manual, the licensee identified that relays in the loss of power EDG start channels were not tested every 18 months, as required by TS 3.3.5. TSs required the channel calibration (including all devices in the channel) be tested every 18 months. Instead, these relays were tested on an 18-month staggered test basis, which resulted in being tested every 36 months.

The root cause analysis was assessed using the inspection guidance in Inspection Procedure 95001 as an aid. Other attributes assessed included: complete and accurate identification of the problem in a timely manner; evaluation and disposition of operability and reportability issues; consideration of extent of condition, generic implications, common cause, and previous occurrences; classification and prioritization of the resolution of the problem; identification of root and contributing causes of the problem; identification of corrective actions which were appropriately focused to correct the problem; and completion of corrective actions in a timely manner commensurate with the safety significance of the issue.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 05000446/2004-002-00 and -01, Auto Start of the CPSES Unit 2 Train B Emergency Diesel Generator and the TDAFW Pump

On October 19, 2004, an unexpected loss of all power to the 138 kV switchyard caused an undervoltage on both Unit 2 safeguards buses. As required, the TDAFW pump started and both safeguards buses slow-transferred to their alternate offsite power supply from the 345 kV switchyard. Investigation revealed that during the transient the Train B safeguards bus slow transfer was delayed for 30 seconds due to erratic behavior of an Agastat time-delay relay. This delay caused an unexpected start of the Train B EDG. The erratic relay was replaced and preferred power was restored from the 138 kV switchyard. The significance and enforcement aspects of this event were documented in NRC Inspection Reports 05000445;446/2005009 and 05000445;446/2005005. This licensee event report is closed.

.2 Failure of ASCO Solenoid Valve Due to Installation of 120 Vac Coil in 125 Vdc Circuit

a. Inspection Scope

On February 7, 2006, Steam Generator 1-04 Feedwater Split Flow Bypass Valve (FSBV) 1-FV-2184 failed closed, causing an annunciator alarm in the control room for high flow to the feedwater nozzle. In accordance with Alarm Procedure ALM-0081A, the operators reduced reactor power until the high flow alarm cleared, at approximately 87 percent power. Valve 1-FV-2184 had closed because Solenoid Operated Valve SOV 1-FV-2184-SV-1 (Train B) had failed open. The solenoid valve was replaced, bypass flow was restored, and reactor power increased to 100 percent. The inspectors interviewed the system engineer and reviewed the associated procedures and SMF-2006-000511-00 to determine if the cause and corrective actions were reasonable and appropriate.

b. Findings

Introduction. A Green, self-revealing noncited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion VII, "Control of Purchased Material, Equipment, and Services," was identified for failing to assure that purchased equipment conform to the procurement documents. This failure resulted in the installation of a solenoid coil with an alternating current voltage rating of 120 Vac, into a circuit with a direct current voltage rating of 125 Vdc, resulting in the failure of Valve 1-FV-2184.

Description. The solenoid valve had been installed on November 5, 2005, during the previous refueling outage. The failure of the coil was caused by the installation of the incorrect voltage type, alternating current instead of direct current. The root cause was determined to be an inadequate Quality Control receipt inspection, which failed to identify the part received had a coil with a voltage rating different than that specified in the purchase order. The vendor, ASCO (Automatic Switch Company), supplied these solenoid valves with the same part number for all available coil voltage ratings. The receipt inspection plan did not specify that the coil voltage rating was an attribute to be verified. This particular solenoid valve with its ac rated coil was received in December 2004 and improperly stocked as a dc coil due to the inadequate receipt inspection.

Valve FSBV 1-FV-2184 redirects approximately 10-15 percent of the main feedwater flow to the auxiliary feedwater nozzle to minimize the potential for flow induced tube failures in the preheater region of Steam Generator 1-04. The feedwater control logic opens and closes the FSBV with the main feedwater isolation valve. During a feedwater line break, the FSBV closes to prevent blowdown of the steam generator through the break. The FSBV also closes to isolate the main feedwater nozzle during auxiliary feedwater injection. The FSBV is a normally open, fail close butterfly valve and it's close signal is executed by de-energizing one of two series solenoid valves. The only mode of failure of the solenoid valve is to cause the FSBV to close, which is its safe position.

The licensee reviewed extent of condition and determined there were no other cases of incorrect voltage coils installed in the plant. The licensee reviewed the previous purchases of solenoid valves and found only one other example of receipt of the wrong coil voltage, in 1995, and that coil had not been installed in the plant.

Analysis. The performance deficiency was the failure to assure the solenoid valve received from the vendor conformed to the specifications of the purchase order. The violation is more than minor because, similar to Example 5.c in Appendix E of Manual Chapter 0612, the solenoid, which did not meet the procurement specifications, was issued from the warehouse, installed in the control circuit for FSBV 1-FV-2184, and placed in service. In addition, this finding is considered more than minor because it is associated with the equipment performance attribute of reliability and affected the mitigating system cornerstone objective to ensure the availability and reliability of the feedwater isolation system to respond to initiating events and prevent undesirable consequences. Using Appendix A of Manual Chapter 0609, the finding screened as (Green) very low safety significance in Phase 1 of the SDP because the finding affected the mitigation system cornerstone but did not represent a loss of system safety function, an actual loss of safety function of a single train, nor was potentially risk significant due to seismic, flooding, or severe weather initiating events. The finding has crosscutting aspects of human performance due to the inadequate receipt inspection verification plan and inattention to detail by the receipt inspection personnel.

Enforcement. Criterion VII of 10 CFR Part 50, Appendix B, requires that "measures shall be established to assure that purchased material, equipment, and services . . . conform to the procurement documents. These measures shall include provisions, . . . (for) examination of products upon delivery." Contrary to the above, in December 2004, the Quality Control receipt inspection failed to assure that the solenoid received conformed to the procurement documents, which had specified the appropriate voltage rating of the coil. Because this failure to perform an adequate receipt inspection is of very low safety significance and has been entered into the corrective action program as SMF-2006-000511-00, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000445/2006002-01, Failure to Perform an Adequate Receipt Inspection of Solenoid Valves.

4OA5 Other Activities

(Closed) Unresolved Item URI 05000445/2005004-02: Failure to Prevent Foreign Material From Entering the Station Service Water Pump Suction

a. Inspection Scope

The inspectors reviewed an operational event in which a vacuum hose that was being used to clean the station service water intake bay floor was drawn into and became lodged in Unit 1 Station Service Water Pump (SSWP) 1-01. The inspectors attended meetings (Plant Event Review Committee and corrective actions), interviewed individuals involved, and reviewed the subsequent SMFs, corrective actions, evaluations, root cause analyses, and procedures.

b. Findings

Introduction. A Green, self-revealing, NCV was identified for failure to implement appropriate corrective action to prevent recurrence of a significant condition adverse to quality, as prescribed in 10 CFR Part 50, Appendix B, Criterion XVI.

Description. On August 17, 2005, while contract divers were in the process of cleaning the station service water intake bay in front of the Unit 1 service water pumps, a vacuum hose became lodged in the Unit 1 SSWP 1-01 (Train A) pump suction housing. The control room received alarms for the pump, noted fluctuating flow, and took immediate action to manually secure the pump. The operations staff entered two 72-hour Technical Specifications: TS 3.7.8(A) for one train of station service water inoperable (Train A), and TS 3.8.1(B) for one EDG inoperable (Train A).

After the pump was secured, the licensee conducted meetings to understand the sequence of events that transpired and to decide on a course of action for inspection and recovery. It was estimated that approximately 8 feet of a 3.75-inch diameter hose was missing. The end of this missing section had a hard plastic nozzle attached via a metal band around the circumference of the hose. The licensee dispatched a diver into the SSWP 1-01 pump suction bay to inspect the pump. The diver retrieved a 5-foot section of hose (approximately) and a 6-inch section that still had the metal banding attached, but the nozzle and approximately 2 feet of hose were not found.

Subsequent inspections during the Fall 2005 refueling outage (1RF11) recovered approximately 8-10 inches of hose plus pieces of the hard plastic nozzle from the endbell of the Train A component cooling water heat exchanger. The heat exchanger and the tubesheet were in good condition with no degradation. The licensee concluded that any of the unaccounted hose pieces had traveled through the heat exchanger and had been discharged to the safe shutdown impoundment.

The licensee assessed the risk of the event, communicated and coordinated activities with the transmission grid manager to ensure grid availability, and set a course of action to restore the pump back to operable. Some of the actions taken included: evaluating any visible damage, rotating the pump by hand to test for free rotation, cleaning the emergency core cooling system lube oil and bearing cooler strainers, flushing the system by running the pump and isolating flow to all components except for the component cooling water heat exchanger, performing two sections of an operability surveillance (two different sets of conditions), and also monitoring bearing temperatures and motor vibrations. SSWP 1-01 was restored to operable on August 18, 2005.

The inspectors reviewed the past history of SSWP failures and discovered two previous events in which a SSWP tripped or was secured because of hose material being ingested into the suction of the pumps. Specifically, in 1996 a diver was nearly sucked into the pump and was forced to cut his diving line to get free. The diving line was ingested. The corrective action taken sought to limit the length of diving line allowed so as to physically not allow the diver to be sucked into the pump. This corrective action failed to address the extent of condition in that it failed to address foreign material exclusion from the pump, thereby failing to protect the SSWPs and prevent recurrence. The finding has a crosscutting aspect related to problem identification and resolution due to inadequate implementation of corrective action.

Analysis. The performance deficiency associated with this violation was the failure of the licensee to implement adequate corrective actions to prevent foreign material from being sucked into the SSWP and causing the pump to trip or be secured.

Initial Characterization of Risk. In accordance with NRC Inspection Manual Chapter 0612, Section 05.03, “Screen for Greater than Minor,” the inspectors determined that the finding was more than minor. This finding is considered more than minor because it is associated with the equipment performance attribute of reliability and affected the mitigating system cornerstone objective to ensure the availability and reliability of the station service water system to respond to initiating events and prevent undesirable consequences.

The inspectors evaluated the issue using the, “Significance Determination Process (SDP) Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones,” provided in NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations." The screening indicated that a Phase 2 estimation was required because the deficiency affected two cornerstones, Initiating Events and Mitigating Systems.

Phase 2 Estimation. In accordance with NRC Inspection Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Determining the Significance of Reactor Inspection Findings for At-Power Situations," the inspectors estimated the risk of the subject finding using the Risk-Informed Inspection Notebook for Comanche Peak Steam Electric Station, Revision 2. The inspectors made the following assumptions:

(1) Service Water Pump 1-01 could not have performed its intended risk-significant function from the time operators shut down the pump on August 17, 2005, at 8:50 a.m, until the pump was returned to service at 3 p.m. the next day. This represents an exposure time of less than 3 days.

(2) Table 2 of the Risk-Informed Inspection Notebook identified that all initiating event scenarios needed to be evaluated when a performance deficiency affects the station service water system.

(3) The initiating event likelihood credit for the loss of station service water special initiator was increased from five to four by the senior reactor analyst in accordance with Usage Rule 1.4 in Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules." This change reflects the fact that the finding increased the likelihood of a loss of service water, a normally running split-train support system.

(4) The station service water system at Comanche Peak provides cooling to the centrifugal charging pumps, the safety injection pumps, the residual heat removal pumps, the motor-driven auxiliary feedwater pumps, and the emergency diesel generators. Therefore, the mitigation capability credit for the HPI, HPR, EIHP, LPR, AFW, EAC, SDC, EMBO, and EDG1 functions were adjusted assuming loss of all Train A equipment.

(5) Given the condition of the pump following the hose ingestion, operators would not have been able to recover the pump upon demand prior to core damage.

The dominant sequences from the notebook were as follows:

| Initiating Event | Sequence | Mitigating Functions | Result |
|---|---|---|---|
| Loss of Offsite Power | 4 | EAC-REC5 | 7 |
| | 7 | EAC-TDAFW | 7 |
| Small-Break LOCA | 5 | HPI | 7 |
| Loss of Service Water | 3 | RCCW-CONS-SEAL | 7 |
| Loss of Vital 125V dc | 3 | AFW-HPI | 7 |

Using the Counting Rule Worksheet, this finding was estimated to be of low to moderate safety significance (WHITE). However, an important assumption made during the Phase 2 estimation was overly conservative, specifically, the assumption that Station Service Water Pump 1-01 was not functional for the entire 3 days exposure period. Therefore, a Phase 3 evaluation was required.

Phase 3 - Internal Events. The results from the notebook estimation were compared with an evaluation developed using a Standardized Plant Analysis Risk (SPAR) model simulation of having Station Service Water Pump 1-01 out of service for test and maintenance. In addition to the assumptions used in the Phase 2 estimation, the SPAR runs were based on the following analyst assumptions:

(1) The SPAR model, Revision 3.21, was the best tool to assess the significance of this event.

(2) Because of the unique cause of the failure of Station Service Water Pump 1-01, the analyst assumed that neither the service water pump nor the diesel generator in Train B would have been out of service for testing or maintenance when the bay cleaning on Train A was taking place.

(3) The initiating event likelihood was adjusted from $4.0 \times 10^{-4}$ to $3.3 \times 10^{-3}$, representing the likelihood that the remaining train fails given that the train is not out of service for test and maintenance. This value was quantified by solving the SWS-1B fault tree in the SPAR model.

(4) Station Service Water Pump 1-01 could not have performed its intended risk-significant function from the time operators shut down the pump on August 17, 2005, at 8:50 a.m, until the pump was returned to service at 3 p.m. the next day. This represented an exposure time of 30 hours 10 minutes.

The analyst used the SPAR model to calculate a $\Delta$CDF over the exposure window of $3.47 \times 10^{-7}$.

Phase 3 - External Events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 significance determination process result provided a risk significance estimation of 7 or greater.

The analyst determined, through review of the licensee's individual plant evaluation of external events, that the only external initiator likely to cause a significant change in risk over a 30-hour exposure time was internal fire. The analyst identified that the following five fire areas were important to determining the risk of this inspection finding: the main control room, the cable spreading room, the safeguards building corridor, the Train B UPS and distribution room, and the Train B electrical equipment area.

Using the fire ignition frequencies provided by the licensee and quantifying conditional core damage probabilities using best available information, the analyst calculated that the total contribution to $\Delta$CDF from internal fires was $5.6 \times 10^{-7}$. Main control room fires contributed more than half of this risk, because Train A is the protected train for remote shutdown should a fire require operators to evacuate the main control room.

Potential Risk Contribution from Large Early Release Frequency (LERF). In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of LERF because the Phase 2 significance determination process result provided a risk significance estimation of 7.

In pressurized water reactors, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for this type of reactor are intersystem loss of coolant accidents, steam generator tube ruptures, and station blackouts.

In accordance with Manual Chapter 0609, Appendix H, "Containment Integrity SDP," the analyst determined that this was a Type A finding, because the finding affected the plant core damage frequency. The analyst evaluated the risk-informed notebook results and determined that Sequences 4 and 7 were both induced by a loss of offsite power that proceeded to a station blackout. However, in accordance with Appendix H, station blackout sequences are screened from further analysis for plants with large dry containments like Comanche Peak. This is described in Table 5.1, “Phase 1 Screening - Type A Findings at Full Power.” Therefore, the analyst determined that the subject performance deficiency was not significant to the LERF.

Risk Significance. As documented above, the analyst determined that the external events important to the risk associated with the subject finding were limited to internal fire. The five fire areas evaluated by the analyst resulted in a $\Delta$CDF of $5.6 \times 10^{-7}$ over the exposure period. The internal initiator contribution to risk was evaluated using the SPAR model and the analyst calculated a $\Delta$CDF over the exposure window of $3.5 \times 10^{-7}$. The total $\Delta$CDF for the subject finding can be calculated as the sum of the internal and external risk:

$$\Delta CDF = 3.5 \times 10^{-7} + 5.6 \times 10^{-7} = 9.1 \times 10^{-7}$$

This result indicates that the finding is best characterized as one of very low risk significance (Green) based primarily on the short time the performance deficiency actually affected plant equipment.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, states, in part, “In the case of significant conditions adverse to quality, the measures shall assure that . . . corrective action is taken to preclude repetition.” Contrary to this requirement, the licensee failed to implement adequate corrective action to prevent foreign material from becoming sucked into SSWP 1-01 on August 17, 2005, when a vacuum hose was sucked into the pump suction housing and caused the operators to secure the pump due to fluctuating low flow conditions. Because this violation was of very low safety significance and it was entered in the corrective action program as SMF-2005-003235-00, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000445/2006002-02, Failure to Prevent Foreign Material From Entering the Station Service Water Pump Suction.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the resident inspection results to Mr. M. Blevins, Senior Vice President and Chief Nuclear Officer, and other members of licensee management on March 28, 2006. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On May 2, 2006, the inspector conducted a telecommunication exit meeting with Mr. T. Hope, Manager, Regulatory Performance, during which changes to the content of the inspection report were identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee Personnel

O. Bhatty, Inservice Test Engineer
M. Blevins, Senior Vice President and Chief Nuclear Officer
T. Clouser, Manager, Shift Operations
R. Flores, Site Vice President, Nuclear Operations
T. Hope, Manager, Regulatory Performance
R. Kidwell, Licensing Engineer
M. Lucas, Vice President Nuclear Engineering and Support
F. Madden, Director, Regulatory Affairs
J. Meyer, Technical Support Manager
P. Polefrone, Plant Manger
S. Sewell, Nuclear Training Manager
J. Skelton, System Engineer
R. Smith, Director, Operations
S. Smith, Director, System Engineering

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

| | | |
|---|---|---|
| 05000445/2006002-01 | NCV | Failure to Perform an Adequate Receipt Inspection of Solenoid Valves (Section 4OA3.2) |
| 05000445/2006002-02 | NCV | Failure to prevent foreign material from entering the station service water pump suction (Section 4OA5.1) |

Closed

| | | |
|---|---|---|
| 05000446/2004-002-00 and -01 | LER | Auto Start of the CPSES Unit 2 Train B Emergency Diesel Generator and the TDAFW Pump (Section 40A3.1) |
| 05000445/2005004-02 | URI | Failure to prevent foreign material from entering the station service water pump suction (Section 4OA5.1) |

Discussed

None

## LIST OF ACRONYMS

| | |
|---|---|
| CDF | core damage frequency |
| CFR | *Code of Federal Regulations* |
| CPSES | Comanche Peak Steam Electric Station |
| EDG | emergency diesel generator |
| FSBV | feedwater split flow bypass valve |
| LER | licensee event report |
| LERF | large early release frequency |
| MSE | maintenance section - electrical |
| NCV | noncited violation |
| NRC | Nuclear Regulatory Commission |
| OPT | operations testing |
| QTE | quick technical evaluation |
| SDP | significance determination process |
| SMF | Smart Form |
| SOP | system operating procedure |
| SPAR | standardized plant analysis risk |
| SSC | structures, systems, or components |
| SSWP | station service water pump |
| TDAFW | turbine-driven auxiliary feed water |
| TS | Technical Specifications |