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Ref: 10CFR50.73(a)(2)(i)(B)

CPSES-200401280
Log # TXX-04086

May 28, 2004

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
CONDITION PROHIBITED BY TECHNICAL SPECIFICATIONS
LICENSEE EVENT REPORT 445/04-002-00

Gentlemen:

Enclosed is Licensee Event Report (LER) 04-002-00 for Comanche Peak Steam Electric Station Units 1 and 2, "Missed Surveillance on Loss of Power Emergency Diesel Generator Start Instrumentation."

This communication contains the following new commitment which will be completed as noted:

Commitment Number	Commitment
27315	The seven affected functions on Unit 2 will be verified via Technical Specification channel calibrations prior to completion of the eighth refueling outage.

IE22

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Rafael Flores
Rafael Flores
Vice President of Nuclear Operations

GLM/gm

Enclosure

c - B. S. Mallett, Region IV
W. D. Johnson, Region IV
M. C. Thadani, NRR
Resident Inspectors, CPSES

Enclosure to TXX-04086

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 07/31/2004
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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Title (4)

CONDITION PROHIBITED BY TECHNICAL SPECIFICATIONS

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Name	Docket Numbers
									CPSES UNIT 2	05000446
04	02	04	04	002	00	05	28	04		05000

Operating Mode (9): 6

Power Level (10): 0

This report is submitted pursuant to the requirements of 10 CFR : (Check all that apply) (11)

	20.2201(b)		20.2203(a)(3)(i)		50.73(a)(2)(i)(C)		50.73(a)(2)(vii)
	20.2201(d)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(A)
	20.2203(a)(1)		20.2203(a)(4)		50.73(a)(2)(ii)(B)		50.73(a)(2)(viii)(B)
	20.2203(a)(2)(i)		50.36(c)(2)(i)(A)		50.73(a)(2)(iii)		50.73(a)(2)(ix)(A)
	20.2203(a)(2)(ii)		50.36(c)(1)(ii)(A)		50.73(a)(2)(iv)(A)		50.72(a)(2)(x)
	20.2203(a)(2)(iii)		50.36(c)(2)		50.73(a)(2)(v)(A)		73.71(a)(4)
	20.2203(a)(2)(iv)		50.46(a)(3)(ii)		50.73(a)(2)(v)(B)		73.71(a)(5)
	20.2203(a)(2)(v)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(C)		OTHER
	20.2203(a)(2)(vi)	X	50.73(a)(2)(i)(B)		50.73(a)(2)(v)(D)		Specify in Abstract below or in NRC Form 366A

Licensee Contact For This LER (12)

Name	Telephone Number (Include Area Code)
Timothy A. Hope - Regulatory Performance Manager	254-897-6370

Complete One Line For Each Component Failure Described in This Report (13)

Cause	System	Component	Manufacturer	Reportable To EPIX	Cause	System	Component	Manufacturer	Reportable To EPIX
				N					

Supplemental Report Expected (14)			EXPECTED SUBMISSION DATE (15)	Month	Day	Year
YES (If YES, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On April 2, 2004, Comanche Peak Steam Electric Station Unit 1 was in Mode 6 during the tenth refueling outage and Unit 2 was in Mode 1 operating at 99.2 percent power. At 1500 hours, while reviewing proposed changes to response times in the Technical Requirements Manual, it was discovered that Technical Specification (TS) Surveillance Requirement (SR) 3.3.5.3 had not been completed within the required frequency for all of the functions specified in TS Table 3.3.5-1.

TXU Generation Company LP (TXU Energy) believes that the cause of the event was less than adequate review of a change to the TS SR 3.3.5.3 frequency due to personnel errors in the review process and inadequate procedure referencing. Corrective actions include performing a risk assessment on Unit 2, performing the required TS surveillance tests on Unit 1, and issuing a Lessons Learned.

All times in this report are approximate and Central Standard Time unless noted otherwise.

I. DESCRIPTION OF REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

Any operation or condition prohibited by the plant's Technical Specifications.

B. PLANT OPERATING CONDITIONS PRIOR TO THE EVENT

On April 2, 2004, Comanche Peak Steam Electric Station (CPSES) Unit 1 was in Mode 6 during the tenth refueling outage and Unit 2 was in Mode 1 operating at 99.2 percent power.

C. STATUS OF STRUCTURES, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

There were no inoperable structures, systems, or components that contributed to the event.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROXIMATE TIMES

Technical Specification (TS) 3.3.5 covers a number of undervoltage functions depicted in TS Table 3.3.5-1, including preferred and alternate offsite source bus undervoltage, 6.9 kv bus loss of voltage and degraded voltage, and 480 degraded and low grid undervoltage functions. SR 3.3.5.3 specifies the performance of a channel calibration on the Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation listed in TS Table 3.3.5-1 every 18 months. SR 3.3.5.4 requires verification that the LOP DG start Engineering Safety Features (ESF) response times are within limits every 18 months on a staggered test basis. The allowable values for the undervoltage relay setpoints are contained in TS Table 3.3.5-1, and the response time values are contained in Technical Requirements Manual (TRM) table 13.3.5-1.

The TS definition for a channel calibration specifies in part "the CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY." The Bases for SR 3.3.5.3 specifies in part "A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy."

At 1500 hours on April 2, 2004, while reviewing proposed changes to the response times in the TRM, Regulatory Affairs personnel (utility, non-licensed) discovered that not all components of the undervoltage channels [EIIS:(EB)(CHA)] were being tested to meet channel calibration requirements at a frequency of 18 months as specified in SR 3.3.5.3. It was discovered that the Agastat timing relays [EIIS:(EB)(CHA)(RLY)] in these channels were only tested under the response time testing requirement (18 months Staggered Test Basis) meaning that each train was being tested approximately every 36 months.

Further investigation revealed that in 1994, a Technical Evaluation had been generated to answer a question which had been raised related to SR 3.3.5.3 and SR 3.3.5.4. Specifically, in 1994 Maintenance personnel (utility, non-licensed) questioned whether or not the calibration of just the undervoltage relays every 18 months and a response time test every 18 months on a staggered test basis (alternate trains) satisfied the TS requirements for calibration if the response time test is satisfactory and no actual adjustment of the Agastat relays are required. Engineering's (utility, non-licensed) response via the Technical Evaluation stated that the undervoltage relays should be calibrated every 18 months and incorrectly indicated that the Agastat timing relays should be tested as one train per outage with a maximum of two refueling cycles between tests. It had previously been determined that satisfactory response time testing methodology also met the requirements for a channel calibration for Agastat relays.

As a result of this incorrect Technical Evaluation, the TS scheduling database was modified on January 1, 1995 to separate the undervoltage relay calibrations from the timing relay time test and also extended the Agastat timing relay test to once every other cycle or at a frequency of 36 months (one train per outage). As a result, since 1995 the Agastat timing relays have not been tested per SR 3.3.5.3 at the required 18 month interval and this constitutes a missed surveillance and a reportable condition prohibited by TS.

E. THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE, OR PROCEDURAL OR PERSONNEL ERROR

While reviewing proposed changes to response times in the Technical Requirements Manual, Regulatory Affairs personnel (utility, non-licensed) discovered that TS Surveillance Requirement 3.3.5.3 had not been completed within the required frequency for all of the functions specified in TS Table 3.3.5-1.

II. COMPONENT OR SYSTEM FAILURES

A. FAILURE MODE, MECHANISM, AND EFFECTS OF EACH FAILED COMPONENT

Not applicable – No component or system failures were identified during this event.

B. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

Not applicable – No component or system failures were identified during this event.

C. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY FAILURE OF COMPONENTS WITH MULTIPLE FUNCTIONS

Not applicable – No component or system failures were identified during this event.

D. FAILED COMPONENT INFORMATION

Not applicable – No component or system failures were identified during this event.

III. ANALYSIS OF THE EVENT

A. SAFETY SYSTEM RESPONSES THAT OCCURRED

Not applicable - no safety system responses occurred as a result of this event.

B. DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY

Not applicable -- No safety system was rendered inoperable.

C. SAFETY CONSEQUENCES AND IMPLICATIONS

The seven affected functions on Unit 1 were verified successfully by performing the required TS channel calibrations during the recently completed tenth refueling outage. The seven affected functions on Unit 2 will be verified via TS channel calibrations prior to completion of the eighth refueling outage. As required by TS SR 3.0.3, an evaluation was performed that determined that the impact of these missed surveillances on plant risk is very small, thus extending the surveillance to the end of the current cycle for Unit 2 is not risk significant.

All of the affected channels that have been tested demonstrated that the channels would have performed their intended safety function, if required. This is consistent with the historical performance of this type of relay at CPSES, where less than one percent of the relay settings were found to be beyond the allowable value. There were no safety system functional failures associated with this event.

Based on the above, it is concluded that this event did not adversely impact the safe operation of CPSES or the health and safety of public.

IV. CAUSE OF THE EVENT

TXU Energy believes that the cause of the event was less than adequate review of a change to the preventive maintenance database frequency for these Agastat timing relays due to personnel errors in the review process and because of inadequate procedure referencing. As previously discussed, a Technical Evaluation was generated in 1994 to answer a question which had been raised related to SR 3.3.5.3 and SR 3.3.5.4. Personnel involved had less than adequate knowledge of the requirements of the procedure for TS questions and, therefore, the procedure governing review and approval of this type of change was not followed. In addition, the procedure governing Technical Evaluations did not prohibit, address, or reference to the correct procedure for questions regarding TS. As a result, personnel with a more detailed knowledge and understanding of the definition and scope of a "channel calibration" with respect to TS were not formally part of the review. Those involved in the review arrived at the wrong conclusion.

LICENSEE EVENT REPORT (LER)

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NARRATIVE (If more space is required, use additional copies of NRC Form 366A) (17)

TXU Energy believes that the Technical Evaluation would have received an adequate review, reached the correct conclusion, and this event would not have occurred had the correct review process, as required by the procedure that was in effect at the time, been followed.

V. CORRECTIVE ACTIONS

The seven affected functions on Unit 1 were verified by successfully performing the required TS channel calibrations during the recently completed tenth refueling outage. The seven affected functions on Unit 2 will be verified via TS channel calibrations prior to completion of the eighth refueling outage. Per TS SR 3.0.3, an evaluation was performed that determined the impact of these missed surveillances on plant risk is very small, thus extending the surveillance to the end of the current cycle for Unit 2 is not risk significant.

In accordance with the CPSES Corrective Action Program, the following actions will be taken:

1. A Lessons Learned describing this event will be issued to Regulatory Affairs, Engineering, Maintenance, and Operations personnel.

2. Training will consider adding this event to the TS training modules operating experience module or other appropriate locations for personnel needing a better understanding of "channel" and "channel calibration" as used within TS.

3. A review will be conducted to ensure that previous changes to the TS scheduling database did not extend the test frequencies for electrical components beyond the TS requirements.

4. The Corrective Action Program procedure will be revised to clarify that any question involving the meaning of TS requirements must be referred to Regulatory Affairs for resolution.

VI. PREVIOUS SIMILAR EVENTS

There has been one other missed surveillance event in the last two years (see LER 446/02-002). However, the details/causes are sufficiently different from the event described in this LER such that the previous corrective actions could not have prevented this event.