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Ref: 10 CFR 50.54(f)

CPSES-200300054
Log # TXX-03008
File # 10010

January 10, 2003

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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445
30 DAY RESPONSE TO NRC BULLETIN 2002-01, "REACTOR PRESSURE VESSEL HEAD DEGRADATION AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY"

REF:
1. Letter logged TXX-02067 from C..L. Terry to the NRC dated April 2, 2002
2. Letter logged TXX-02094 from C. L. Terry to the NRC dated May 17, 2002
3. Letter logged TXX-02162 from C. L. Terry to the NRC dated September 11, 2002
4. NRC Letter from D. H. Jaffe to C. L. Terry dated December 2, 2002

Gentlemen:

In accordance with 10CFR50.54(f), attached is the TXU Generation Company LP (TXU Energy) 30-day response to U.S. Nuclear Regulatory Commission (NRC) Bulletins 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" dated March 18, 2002. Per Phone conversation with Mr. D. H. Jaffe of the NRC, TXU Energy received an extension to the 30-day response to allow inclusion of additional inspections completed on December 13, 2003. In addition, this response fulfills requirements for the 30-day responses to Bulletins 2001-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" and 2002-02, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity".

A088
A095
A096

TXU

This communication contains the following revised commitment:

Commitment Number	Commitment
27273	Future inspection plans at CPSES will be developed consistent with industry-developed consensus inspection requirements acceptable to the NRC as referenced within the "Discussion" text of Bulletin 2002-02. TXU Energy will provide our future inspection plans for each Unit no later than 90 days prior to the next scheduled refueling outage for that unit.

If you should have any questions, please call Mr. J. D. Seawright at (254) 897-0140 (Email - jseawright@txu.com).

I state under penalty of perjury that the foregoing is true and correct.

Executed on January 10, 2002.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

C. L. Terry
Senior Vice President and Principal Nuclear Officer

By: Roger D. Walker
Roger D. Walker
Regulatory Affairs Manager

JDS/js
Attachment

c - E. W. Merschoff, Region IV
W. D. Johnson, Region IV
D. H. Jaffe, NRR
Resident Inspectors, CPSES

NRC Bulletin 2002-01 Required Action

Within 30 days after plant restart following the next inspection of the reactor pressure vessel head to identify any degradation, all PWR addressees are required to submit to the NRC the following information:

A. the inspection scope (if different than that provided in response to Item 1.D.) and results, including the location, size, and nature of any degradation detected,

B. the corrective actions taken and the root cause of the degradation.

Commitment Restatement from 02-01 Response

In response to NRC Bulletin 2002-01 (Ref. 1), TXU Energy made the following commitments (Ref. 2) regarding reactor vessel head inspections:

- *CPSES will perform a remote visual inspection of the bare metal upper head of both reactor vessels during their respective next refueling outages. The Unit 2 vessel head inspection will occur during 2RFO6 in April 2002 followed by Unit 1 during 1RFO9 in the fall of 2002. These inspections will be performed to support an engineering evaluation of the condition of the vessel heads with regard to the issues addressed in NRC Bulletin 2002-01.*

- *TXU Energy will submit the inspection scope, results, corrective actions taken and root cause of any degradation found within 30 days after plant restart following the next reactor pressure vessel head inspection. The next inspection is currently planned for the next refueling outage for Units 1 and 2 (1RFO9 and 2RFO6, respectively).*

Pursuant to the second of these commitments, this letter describes the inspection performed during the recently completed refueling outage for Comanche Peak Unit 2 and summarizes the observed condition of the reactor vessel head.

Completed Inspection Description

<u>Scope</u>
During 1RFO9, TXU Energy conducted an inspection of the Comanche Peak Unit 1 reactor vessel head consistent with our response to NRC Bulletin 2002-01. This inspection also met the requirements stated in NRC Bulletin 2001-01 for an Effective Visual Exam. One hundred percent of the general surface area of the reactor vessel head and all penetration tube bases (78 CRDM penetration tubes and one head vent line) at the reactor vessel head outer surface were inspected.

<u>Methods</u>
The inspection employed a remotely controlled crawler to deliver video cameras to all areas of the reactor vessel head surface under the upper tier of reflective metallic insulation. Two insulation panels were removed that allowed complete access by the crawler to perform a

360°inspection at the base of 62 penetrations. The remaining 17 penetrations are within the lower tier of reflective metallic insulation and were also inspected primarily with the crawler. Those portions of approximately eight tubes inaccessible to the crawler were inspected via video probe. The CRDM cooling shroud support ring rests approximately 1-1/2" above the reactor vessel head outer surface. However, unlike CPSES Unit 2, the Unit 1 insulation panels adjacent to the cooling shroud base rest directly on the RPV head surface, hampering inspection access to this area from the reactor vessel head flange.

Summary of Results

The RPV head surface was generally coated with a very thin layer of a gray, powdery material that was easily disturbed by the tracks of the crawler. A light scattering of slightly larger particles was also noted. This powder did not degrade the inspectability of either the general surface of the head or the base of the penetration tubes and was judged to be a thinner layer than that previously observed in Unit 2. However, just as in Unit 2, chemical analysis results indicate that this dust is predominately representative of the common constituents of concrete.

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 judged (by reference to the known diameter of the tube itself) to be on the order of ¼" 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 (<1/3) of the circumference. The material was clearly composed largely of angular metal bits (i.e., chips, shavings, etc.) and short pieces of wire possibly from a wire wheel. Occasional green and orange bits (presumably electrical wire insulation) were also observed mixed with the metal particles. In no case did these deposits hinder future inspections and were each judged to be benign.

Several tubes exhibited localized accumulations of less metallic appearing debris with radial widths only approximately one sixteenth 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. These trails were consistent with the residue that would result from the slow evaporation from the wetted surface that would remain after the main drop of water flowed down the tube. With no evidence of an active leak from above or below, these deposits were judged as benign and therefore acceptable.

One area around tubes 68, 56, and 75 exhibited evidence of a spill. This location is generally beneath the head vent valve. This area has evidence of flow from many points above including trails down these tubes and from the joints of the insulation panels. The deposit on the head does contact the listed tubes although generally for only a portion of the tube circumference as the flow either encountered the tube or ran down the tube itself to the head. The material was variously off-white to yellow-brown and in some local areas had a rust-stained appearance. The deposit generally exhibited little thickness and can be characterized more as individual "trails" rather than a uniform continuous flow field over the area. A thin metal scraping tool was inserted under the insulation to disturb the deposit area between Tubes 68 and 75, verify the deposit thickness, and confirm the presence of sound metal beneath the deposit. The nature and appearance was consistent with the known history of spills from head vent connection / disconnection outage activities. One small "pile" of flaky material against tube 75 with a localized maximum width from the tube wall and height both on the order of ½" and a circumferential extent of ~1 - 2" was observed. However, this accumulation was judged to be associated with the spill deposit material and exhibited no signs of active leakage.

Tube 31 was investigated during 1RFO8 due to boric acid deposits observed both above and within the CRDM cooling shroud. This condition was documented and evaluated at that time in the corrective action program (SMF-2001-000728) and was dispositioned as spill-related rather than as a leak. As a result of this prior condition, a careful visual inspection was conducted during 1RFO9. No evidence of recent changes associated with the previous stains and residue above the cooling shroud (near the intermediate canopy seal weld) as well as above the insulation (near the lower canopy seal weld) within the shroud was observed that would be indicative of newly deposited boric acid. During 1RFO8, the head surface was also cleaned on a best-effort basis using a vacuum cleaner and small hose. This area of the head was investigated early in 1RFO9 before the crawler exam and was found generally clean. A deposit ~1/4" thick was present on the tube but was disconnected from the head surface. A small deposit, related to the spill running down the tube, was also seen on the head adjacent to the tube. Generally the scattered loose material observed in videos from the 1RFO8 inspection and cleaning was gone and no indications of new deposits were identified. During the crawler examination, the remaining material at the base of the tube was disturbed by the crawler and in particular by the crawler umbilical cable as it wrapped around the tube base. Careful examination of this location confirmed that there was no evidence of any active leak from either above the insulation or at the head. These observations were entirely consistent with the 1RFO8 inspection findings of no leak source and affirmed the conclusion that the observed deposits were most probably outage spill related.

No penetration tube bases exhibited characteristics associated with a leak from within the annular gap surrounding the tube. As noted above, there were also no instances where debris or other deposits impeded this examination or would impede a future exam. The general dusting observed was judged benign and the head surface was readily inspectable despite its presence. Therefore, a general cleaning of the reactor vessel head surface was determined to be unnecessary and the benefit would not justify the dose.

Supplemental dust analysis

During the visual examination two samples of the dust that had collected on the metal surface were obtained, generally from opposite sides of the RPV head.

Sample one, collected on a cotton glove liner, was a drag type sample that collected dust and any crystals that were accumulated in the area.

The ICP analysis results showed high levels of calcium, potassium, and magnesium and trace levels of iron and other alloy type metals. No boron was found in this sample And no anion analyses was performed.

Sample One Analysis Data (Relative Abundance)

Calcium	69%
Magnesium	24%
Potassium	5%
Aluminum	<0.5%
Boron	<MDA*
Iron	<0.5%
All others	<1%

*Less than the minimum detection level of the analysis.

This is consistent with what is seen with concrete and environmental dust on metal surfaces. The levels and types of contaminants suggest that no corrosion attack has occurred at this location.

Sample two was collected using a gauze pad precleaned to minimize any contaminants from the gauze manufacture. The area sampled was approximately one square foot in size. Boron and lithium were present in the material found in this area. The presence of lithium gives evidence to wetting by reactor coolant at some time previous to the sample time.

The gauze pad showed no visual evidence of boric acid crystals.

Sample Two ICP Analysis Data (Relative Abundance)

Calcium	60%
Magnesium	2%
Potassium	12%
Aluminum	1%
Boron	Over range*
Lithium	3%
Iron	22%
All others	<1%

*The sample quantity and preparation restricted an analysis by boron titration. ICP analyses gave only qualitative information and did not allow a quantitative determination.

This data and the radioisotopic analyses are consistent with a dusty area that had been wetted by reactor coolant during a previous venting evolution. However, there was no visual evidence of direct wetting of the head in the sample area based on the appearance of the dust. Although the presence of iron in the analytical results suggests the possibility of limited corrosion, there was no visual evidence of boric acid crystals or corrosion products within this general area of the head.

Intermediate Canopy Seal Weld Leak

Prior to reaching 100% power following 1RFO9, Unit 1 experienced a dropped control rod. The cause was determined to be a leak in the Tube 31 intermediate canopy seal weld. This is the same tube discussed above with boric acid deposits observed in 1RFO8 and this most recent event is also fully addressed in the corrective action program (SMF-2002-004167). The extent of condition evaluation included an inspection for evidence of other canopy seal weld leaks and an inspection of the RPV head beneath the insulation at the base of the affected tube. As noted above, this tube was specifically inspected early in 1RFO9 prior to the crawler exam due to deposits of boric acid identified in 1RFO8. These 1RFO9 inspections affirmed the previous conclusion that the deposits resulted from a non-operational event.

The observed condition on the RPV head in the general vicinity of the base of Tube 31 included a somewhat "fluffy" boric acid pile and a flow area generally located downhill from Tube 31. This combination of deposit characteristics suggests formation during different operating conditions, which is consistent with plant conditions following 1RFO9. Although a detailed review of the operating temperatures has not been completed in this context, the plant did transition to Mode 1 and back to Mode 5 several times during November and early December. The flow rates observed and the extent of the flow field would suggest flow field formation at lower operating temperatures when the water would boil off at a much slower rate. At normal operating temperature, a small leak (< ~0.1 gpm) would not be capable of locally cooling the head sufficiently to support flow over the affected area. The relatively rapid flashing would be expected to produce a fluffy boric acid deposit similar to that observed. Therefore, the observed conditions appear consistent with recent plant operation.

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 generally downhill from there. This area was "scratched / scraped" to leave randomly oriented marks in the stain to allow easier discernment of any future changes or the lack thereof during subsequent inspections. Sound metal was present and no consequential local degradation of the head due to boric acid wastage was observed. The as-left condition was thoroughly documented via digital photos for reference during future inspections.

Summary and Conclusion

In summary, an inspection of the Comanche Peak Unit 1 reactor vessel head bare metal upper surface was completed consistent with our commitment in response to NRC Bulletin 2002-01. No degradation of the head was observed and no evidence of reactor coolant system pressure boundary leakage onto the RPV head during power operation was found other than that discussed associated with an intermediate canopy seal weld leak. No consequential limitations were encountered that prevented access or inhibited effective inspection of either the general head surface or the annulus at the base of each penetration tube.

TXU Energy will continue to monitor this issue through participation in relevant industry organizations. Future inspection plans for the Comanche Peak Unit 1 reactor vessel upper head are currently under review. However, per your letter of Dec. 2, 2002 (Reference 4) TXU Energy will provide our future inspection plans for each Unit no later than 90 days prior to the next scheduled refueling outage for that unit.