September 24, 2007

Mr. M. R. Blevins
Senior Vice President
& Chief Nuclear Officer
TXU Power
ATTN: Regulatory Affairs
P. O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2 - SUPPLEMENTAL REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST (LAR 06-07), REVISION TO TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES - OPERATING," EXTENSION OF COMPLETION TIMES FOR OFFSITE CIRCUITS (TAC NOS. MD4068 AND MD4069)

Dear Mr. Blevins:

By letter dated January 18, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML070240385), TXU Generation Company LP (the licensee) requested the subject license amendment for Comanche Peak Steam Electric Station (CPSES), Units 1 and 2. The proposed changes would revise Technical Specification (TS) 3.8.1, "AC Sources - Operating," to extend the allowable completion time associated with an inoperable offsite circuit (i.e., a startup transformer) from 72 hours to 30 days.

The Nuclear Regulatory Commission (NRC) staff issued a request for additional information (RAI) via e-mail, dated June 19, 2007 (ADAMS Accession No. ML071700165). The licensee provided its response to the RAI by letter dated July 18, 2007 (ADAMS Accession No. ML072050526). The NRC staff's questions and concerns were discussed with the licensee during conference calls on August 1, 2007 and August 30, 2007. The NRC staff continues its review of the proposed TS changes for CPSES, Units 1 and 2, related to offsite power circuits and the licensee's response to the RAI.

Based on the results of our review to date, the NRC staff has identified the additional information needed to complete the review in the enclosure to this letter. Your response is requested within 30 days from the date of this letter. In order for NRC to complete its review and reach a final safety decision in a timely manner, it is essential that you respond with adequate and sufficient information. If your responses are not sufficient or not timely, we may act on your application in accordance with Section 2.108 of Title 10 of the *Code of Federal Regulations*, "Denial of Application."

Please contact Balwant K. Singal at 301-415-3016, if you have any questions.

Sincerely,

/RA/

John W. Lubinski, Deputy Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosure: As stated

cc w/encl: See next page

Please contact Balwant K. Singal at 301-415-3016, if you have any questions.

Sincerely,

/RA/

John W. Lubinski, Deputy Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosure: As stated

cc w/encl: See next page

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GWilson, NRR
MRubin, NRR

ADAMS Accession No.: ML072540641

* Memo dated 8/29/07 from APLA transmitting RAI
**Memo dated 9/13/07 from EEEB transmitting RAI

OFFICE	NRR/LPL4/PM	NRR/LPL4/LA	NRR/APLA	NRR/EEEB	NRR/LPL4/BC
NAME	BSingal	JBurkhardt	MRubin*	GWilson**	THiltz
DATE	9/18/07	9/18/07	8/29/07	9/13/07	9/24/07

OFFICIAL AGENCY RECORD

REQUEST FOR ADDITIONAL INFORMATION

COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2

LICENSE AMENDMENT REQUEST (LAR 06-07)

REVISION TO TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES - OPERATING,"

EXTENSION OF COMPLETION TIMES FOR OFFSITE CIRCUITS

By letter dated January 18, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML070240385), TXU Generation Company LP (the licensee) requested the subject license amendment for Comanche Peak Steam Electric Station (CPSES), Units 1 and 2. The proposed changes would revise Technical Specification (TS) 3.8.1, "AC Sources - Operating," to extend the allowable completion time (CT) associated with an inoperable offsite circuit (i.e., a startup transformer) from 72 hours to 30 days.

The Nuclear Regulatory Commission (NRC) staff issued a request for additional information (RAI) via e-mail, dated June 19, 2007 (ADAMS Accession No. ML071700165). The licensee provided response to the RAI by letter dated July 18, 2007 (ADAMS Accession No. ML072050526). The NRC staff has completed its review of the proposed TS changes for CPSES, Units 1 and 2, related to offsite power circuits and the licensee's response to the RAI.

Based on the results of our review, the NRC staff has identified the following additional information needed to complete the review:

1. The licensee responses to RAI #1E and #4 are not clear as to how the unavailability of one of the two startup transformers (STs) is being specifically considered in the probabilistic risk assessment (PRA) model to obtain the risk analyses results. Specifically, it is not clear that the impact to the frequency of a plant-centered loss of offsite power (LOOP) and the impact to consequential LOOP (subsequent to any non-LOOP initiating event), are both addressed, and in what manner. The initial submittal identified a plant-centered baseline LOOP frequency, which was then identified as having been reduced for this analysis. The response to RAI #1E stated that the re-evaluation of industry events considering the configuration of a single available ST "resulted in an increase in the LOOP frequency for the 30 day completion time (CT)." The response to RAI #4 stated that "the plant-centered branch is composed of the initiating event (plant-centered event frequency discussed in question 1 as a reduced frequency) and the individual component failures for the 24 hour mission time." Hence, it is uncertain if the risk increase is being calculated due to an increased frequency of plant-centered LOOP, or from mission time failures of the available ST, or both.

   Therefore, the NRC staff requests the licensee clarify its responses to these RAI to address:

   a. What LOOP frequencies are specifically used in the analyses and how are they calculated?

ENCLOSURE

b. When is the "reduced LOOP" applied in the analyses?

c. How is the LOOP frequency impact of the configuration changing from two switchyards/transformers to one addressed?

d. Is the unavailable transformer accounted for directly in the LOOP frequency, or only in the mitigation model over the mission time?

e. What is the source of the risk increase: sequences with a LOOP initiator? Sequences with mission time transformer failure? Both? What is the breakdown of the risk profile?

f. Is the spare ST credited in the PRA model?

It may assist the staff in its review, if the licensee also submitted the following information:

- Detailed basis and calculations for the baseline LOOP frequency (including fault tree models if applicable).

- Detailed basis and calculations for the "reduced plant-centered" LOOP frequency (including fault tree models if applicable).

- Description of the impact of the unavailability of one of the two STs, specifically addressing the impact on LOOP frequency and consequential LOOP probability (including fault tree models if applicable).

- Initiating events and sequence contributions and cutsets report (including appropriate descriptions of basic events) for baseline model core damage frequency (CDF) which address 90 percent of the CDF.

- Initiating events and sequence contributions and cutsets report (including appropriate descriptions of basic events) for extended allowed outage time case CDF which address 90 percent of the CDF.

2. The licensee's response to RAIs #9, #11, and #12 addressing the risk from fires and other external events stated that for core damage to occur following a LOOP, both emergency diesel generators (EDGs) and the turbine-driven auxiliary feedwater (TDAFW) pump must fail. This would appear to make the assumption that reactor coolant pump (RCP) seal integrity is not an issue for station blackout (SBO) conditions, which would be inconsistent with the staff's understanding of the CPSES, Units 1 and 2, design for a loss of RCP seal cooling during an SBO over an extended period (i.e., 18 days for restoration of offsite power). Given this response for fire and external events, this also raises questions regarding the internal events PRA model with regard to how RCP seal integrity is addressed. Therefore, the staff requests the licensee to submit the following information:

   a. Detailed description of the assumptions and equipment relied upon in the CPSES, Units 1 and 2, PRA for RCP seal integrity.

b. Detailed description of the success criteria for maintaining RCP seal integrity, especially identifying any differences applied to different initiating events or accident sequences, and any initiators or sequences for which RCP seal integrity is not considered in the PRA model.

c. Justification for the exclusion of RCP seal integrity considerations for the bounding evaluations of fire risk and other external events risk.

3. The licensee's response to RAI #9 stated that the scenario leading to core damage after a fire assumes an independent (from the effects of a fire) common cause failure (CCF) of the EDGs and an independent (from the effects of the fire) failure of the TDAFW pump. Has the licensee confirmed that necessary cables for these components are not located in any of the same fire areas being evaluated such that their failure would not be independent? In addition, the response did not address the potential for a fire-induced isolation of the ST as was specifically requested. Is the electrical isolation of the one ST due to a fire (or internal flood/spray) possible? What is the risk impact of such an event? Has the licensee considered the potential impacts of spurious actuations due to fire-induced cable faults on the fire risk impact of the proposed change?

4. The licensee's responses to RAIs #1C and #1D require further clarifications:

a. It was stated that in the event of deteriorating weather during the extended CT, "work will be postponed or suspended, or compensatory measures will be initiated to reduce risk." Stopping maintenance work will not restore the ST; therefore, the efficacy of this action with regard to reducing plant risk should be further explained in terms of the pre-planning for restoration during the planned maintenance activities and expected restoration times for various points in the planned outage. Further, what specific compensatory measures would be applied to this hypothetical condition which could reduce risk?

b. For planned maintenance, it is stated that "times of peak tornado or thunderstorm frequency or likelihood of winter ice storms will be avoided..." However, in a subsequent section it is implied that only the period from April to June would be avoided. The licensee is again requested to clarify its intended commitment with regard to scheduling planned maintenance.

c. With regard to the likelihood of severe weather during the balance of the calendar year, the response (RAI #1D) simply restates the analysis assumption of average annual historical weather without justification for not assuming a higher frequency, such that the annual weighted average equals the annual average with regard to weather-related LOOP events.

d. It is stated that increasing the test and maintenance unavailabilities by 9 percent (i.e., one-eleventh) is conservative since these include corrective maintenance. This implies that corrective maintenance is already included in the risk analyses for the 30 day maintenance period. If corrective maintenance is not so included, then increasing the total maintenance unavailability by 9 percent is not conservative. The licensee should clarify its response.

5. The licensee's response to RAI #14 requires further clarifications:

   a. The response to RAI #14A discusses the tier 3 configuration risk management program (CRMP) in detail, but does not address the specific question as to whether there are any tier 2 restrictions which are commitments.

   b. The response to RAI #14C does not address the specific question as to if there are any unique controls in place in the switchyard during this maintenance, but instead repeats the various procedural and administrative controls of the submittal. What is unique about the switchyard controls during the maintenance period which justifies a reduced plant-centered LOOP frequency?

6. The licensee's response to RAI #17 identified that no repair/recovery credit for the STs was assumed in the risk analysis. However, further clarification was provided that recovery of EDGs was assumed, which is directly relevant to the risk analyses of the proposed change. Further, the Individual Plant Examination (IPE) evaluation by the staff identified that the PRA credited repair/recovery of failed systems was a weakness in the IPE. The licensee should discuss the use of EDGs and all other relevant equipment repairs/recoveries in the PRA model, to include a) the non-recovery probabilities assumed, including their basis, b) sequence-specific conditions considered for application of recoveries, including applicability to multiple EDG failures or CCFs of EDGs, or other equipment, c) the assumed time available for recovery considering the status of decay heat removal systems and RCP seal integrity, d) applicability of recoveries to SBO scenarios, and e) sensitivity of the analyses results to the EDG and other equipment recovery assumptions, individually and as a group.

7. The licensee's response to RAI #18 and subsequent clarifications regarding the use of the spare ST indicate that a minimum of 18 days would be required to make use of the transformer, and that it is not viable to use the spare ST to facilitate planned maintenance activities. Given that the licensee has also stated in response to RAI #17 that recovery and repair of a failed ST is not credited, then in the event of a failure of the one operable ST during the extended 30 day CT, the EDGs would have to be relied upon to provide alternating current (AC) power to ensure decay heat removal and inventory control for a minimum of 18 days, assuming that immediate action is taken upon failure of the operating ST to begin to place the spare ST into service.

   a. How do the risk calculations reflect an extended mission time of 18 days for plant-centered LOOP events during the extended CT?

   b. Given the licensee's stated ST fault rate of 1.43E-6 per hour (RAI #4), over the 30-day CT, the probability of a LOOP induced by an ST fault is 1.03E-3. Combining this with the CCF of the EDGs of 6E-4 (RAI #9) yields a 6.18E-7 cutset for a 24-hour mission time. Over 18 days, this would yield a probability of SBO and subsequent core damage of 1.1E-5. While this value conservatively neglects restoration of the EDGs and assumes linearity of the CCF term, it also non-conservatively neglects other equipment failures over the 18-day mission time and does not address any other initiating events, including fires. Thus, risk from this and other similar sequences should be addressed.

c. If an ST fault were to occur during the extended CT, when would the spare ST be placed into service? Are all required parts, procedures, trained personnel, etc. available during the extended CT to accomplish the replacement?

8. Multi-unit sites typically are considered independently with regard to the risk metrics, based on the fact that a proposed TS change is unlikely to be simultaneously applied. However, since the CPSES, Units 1 and 2, design involves shared STs, and the proposed change would involve a configuration in which both reactor units rely upon the same ST for offsite power with no backup source available for an extended period, and the failure of this ST would cause a LOOP initiating event in both units simultaneously, the total risk of core damage in either unit should be considered. That is, incremental conditional core damage probability (ICCDP) = (LOOP over 30 days) * [(CCDP - Unit 1 over 18 days) + (CCDP - Unit 2 over 18 days)]. Such an evaluation should include consideration of inter-unit CCF of EDGs and any potential limitations on repair/recovery activities in multiple units. The licensee should identify the total risk for the two-unit site.

9. The licensee's submittal identified that internal floods are not included in the quantitative risk analyses. However, the IPE identifies that internal floods were quantified and in fact were a significant contributor to the risk profile (i.e., 23 percent of the internal events CDF and a frequency of 1.29E-5 per year, which is more than the reported CDF for all other internal event initiators in the submittal). The licensee should justify why internal floods were removed from the baseline PRA model.

10. The licensee's submittal identified that significant A and B level facts and observations (F&Os) from the peer review have been addressed, and provided details for three A-level F&Os. In its review of the IPE submittal, the staff had identified a number of generic weaknesses in the CPSES, Units 1 and 2, PRA models which would be relevant to the PRA quality for this application, including use of generic data, low CCF factors and scope of CCF analyses, low offsite power recovery factors, dual unit initiators not considered, significant repair/recovery credit (addressed above in question no. 6). The licensee is requested to provide detailed resolutions of the B-level peer review F&Os, and discuss how the issues identified by the staff IPE review have been addressed.

11. In the telephone conference on August 1, 2007, the licensee identified a precedent for Beaver Valley which was not cited in their submittal or RAI responses. The staff reviewed the Beaver Valley TS for AC Sources and cannot confirm that such a precedent exists, as the CT for AC sources is 72 hours for Beaver Valley. The licensee should clarify this issue.

12. Describe the capability, capacity, and design of the diesel generator(s) proposed as compensatory measures (as discussed during the phone conference on August 30, 2007) while the preferred offsite power circuit is removed from service. At a minimum, the description shall include how quickly safe-shutdown equipment (on both units) will be powered (i.e., maximum time to power unit safe-shutdown circuits) from on-set of a

loss of offsite power event, and the design basis demonstrating proper sizing of the proposed compensatory measure diesel generator(s) to supply the safe-shutdown loads on both units. Furthermore, demonstrate that the maximum time to power the safe-shutdown loads using the proposed compensatory measure diesel generator(s) provides assurance that the specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary will not be exceeded.

cc:

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