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July 18, 2007

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
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION TO LICENSE AMENDMENT REQUEST (LAR) 06-007 REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1, "AC SOURCES - OPERATING," EXTENSION OF COMPLETION TIMES FOR OFFSITE CIRCUITS

REFERENCES:
1. TXU Power letter, logged TXX-06172, from Mike Blevins to the NRC dated October 31, 2007
2. TXU Power letter, logged TXX-07012, from Mike Blevins to the NRC dated January 18, 2007

Dear Sir or Madam:

Based on questions provided by Mr. Mohan Thadani of the NRC in an email dated June 19, 2007, TXU Generation Company, LP (Luminant Power) hereby provides additional information regarding LAR 06-07, questions 1 to 18. On July 2, 2007 after a teleconference with the NRC to clarify questions 1 thru 18, Mr. Mohan Thadani provided three more requests for additional information (RAI) on July 3, 2007 via email. Luminant Power hereby provides the additional information requested in responses 19 thru 21.

The additional information provided in Attachment 1 does not impact the conclusions of the No Significant Hazards Consideration provided in Reference 1. The use of the word "planned" was intentional on Page 15 of Attachment 1 to Reference 2. The description of the administrative controls in INSERT B of Attachment 3 should have been the same as the administrative controls on Page 15 of Attachment 1 to Reference 2. Consequently, Attachment 2 and 3 of this document are provided to replace Attachment 3 of Page 5 of 5 to Reference 2 and Attachment 5 of Page 2 of 3 to Reference 2, respectively.

In accordance with 10CFR50.91, a copy of this submittal is being provided to the designated Texas State official.

As suggested in the NRC's RAIs, this communication contains the following new commitments which will be completed as noted:

A001

NRR

Commitment Number	Commitments	Due Date/Event
27441	Before utilizing the 30 day Completion Time for planned maintenance of a Startup Transformer, the following provisions will be made: 1. Service and support equipment will be pre-staged 2. Replacement parts will be pre-staged 3. Experienced personnel will be available to perform work 4. Pre-job briefs will be conducted	Administrative controls in place within 120 days of NRC approval.
27443	During the 30 day Completion Time when a Startup Transformer is inoperable, the monthly surveillance testing of the EDGs is allowed but the following equipment will not to be removed from service: 1. AC or DC electric power, electric system components, or electric equipment feeding the operating startup transformer 2. Either train of the station service water system, components, or equipment 3. The Turbine Driven Auxiliary Feedwater Pump and the associated equipment and valves required for decay heat removal	Administrative controls in place within 120 days of NRC approval.
27444	Planned maintenance of a Startup Transformer will be scheduled during periods when seasonal weather conditions at CPSES have historically not been severe or threatening to offsite power. Times of peak tornado or thunderstorm frequency or likelihood of winter ice storms will be avoided. Times of optimum grid conditions will be considered in selecting the pre-planned maintenance window. The 30 day Completion Time may be used to perform corrective maintenance or to mitigate emergent conditions. If weather conditions deteriorate such that risk to the plant increases, the Startup Transformer will be restored to operable status if possible, or work will be either postponed or suspended, or compensatory measures will be initiated to reduce risk.	Administrative controls in place within 120 days of NRC approval.
27446	When utilizing the 30 day Completion Time for one inoperable Startup Transformer, no switchyard activity that would increase the probability of loss of offsite power will be allowed.	Administrative controls in place within 120 days of NRC approval.

The Commitment number is used by Luminant Power for the internal tracking of CPSES commitments.

Should you have any questions, please contact Tamera J. Ervin at 254-897-6902.

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

Executed on July 18, 2007.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Fred W. Madden
Director, Oversight & Regulatory Affairs

Attachments -
1. Response to Request for Additional Information
2. Revised Technical Specifications Bases Inserts Page (Mark Up) (For Information Only)
3. Revised Retyped Technical Specifications Bases Page (For Information Only)

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

Ms. Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
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ATTACHMENT 1 TO TXX-07109

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO LICENSE AMENDMENT REQUEST (LAR) 06-007 REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1, "AC SOURCES - OPERATING," EXTENSION OF COMPLETION TIMES FOR OFFSITE CIRCUITS

1. **A reduced loss of offsite power (LOOP) frequency was applied for the risk analyses when the startup transformer (ST) is unavailable. The staff has additional questions about the use of a reduced frequency.**

A. **The licensee stated that plant-centered events were removed from the industry data used to develop the Comanche Peak Steam Electric Station (CPSES) loss of offsite power frequency, based on administrative prohibition of work which could affect offsite power, including work in the switchyard. However, the proposed Technical Specification (TS) change is specifically requested to permit extended maintenance activities on equipment in the switchyard (i.e., the ST), which would indicate that switchyard access and activities would be greater than when such maintenance activities are not ongoing. This would indicate that plant-centered events may be more likely, and that their frequency should therefore be greater than the nominal average. The licensee is requested to justify the assumptions regarding plant-centered events and their proposed administrative controls with regards to the assumption of a reduced LOOP frequency.**

Response:

Work in the switchyard is administratively controlled by the Shift Manager, Operations, who by plant procedure STA-629 "Switchyard Control," has sole authority to grant access to the switchyard. Transformers XST1 and XST2 are physically located in the protected area and not in the switchyard. Since the transformers are physically independent from the switchyard, work on the transformer does not affect the switchyard. Similarly, as noted in LAR 06-007, work in the switchyard will be minimized during the time the transformers are being maintained to preclude plant-centered events from occurring. Therefore, the assumptions regarding plant-centered events and their proposed administrative controls with regards to the assumption of a reduced LOOP frequency remain valid.

B. The licensee stated that plant-centered industry events which resulted in a LOOP were excluded in performing the reduced LOOP frequency calculations. The staff is concerned that some plant-centered industry events which have occurred may have involved subtle interactions with offsite power which may not have been fully understood prior to the event occurrence, and that an "after the fact" review of such events in order to exclude them from consideration has the advantage of a detailed evaluation as to the cause of the event. The licensee is requested to provide details regarding the review and disposition of these excluded plant-centered industry events, with regards to their assurance that CPSES administrative controls as proposed in their submittal would in fact have prevented occurrence of a LOOP, given what was reasonably understood regarding the interaction of the plant activities with offsite power.

Response:

All of the events listed in the Electric Power Research Institute (EPRI) document, "Loss of Off-Site Power at U.S. Nuclear Power Plants," were reviewed to determine the cause of the LOOP. Since the work in the switchyard will be administratively controlled, those events which were caused by personnel actions in the switchyard were excluded from the plant-centered industry and thus the plant-centered failure probability. Any event which was caused by equipment failure or could not be attributed to personnel actions only, remained included in the plant-centered failure probability calculation. If the event was not conclusively a personnel error it remained in the data for plant-centered failure probability calculations.

The events excluded in the original plant-centered evaluation were revisited along with all of the events in the EPRI database and will be discussed later in request for additional information (RAI) 1E below.

C. **The weather-centered contribution to LOOP frequency was reduced by 70%, effectively assuming that ST maintenance would only occur in the off-peak periods for severe weather. The licensee has only stated (Attachment 1 page 15) that "weather conditions must be conducive to perform planned maintenance on the offsite circuits." The licensee has not identified any commitment to specifically restrict ST maintenance based on the peak period of severe weather which was the basis of the reduced LOOP frequency. The licensee is requested to propose more specific restrictions on voluntary ST maintenance such that the assumptions of the risk analysis are maintained, including the applicability of such restrictions during unplanned ST maintenance.**

Response:

CPSES is required by plant procedures to consider the potential for severe weather when scheduling work. Specifically, plant procedures STA-604 and WCI-203 state, "Weekly Surveillance/Work Scheduling," requires, "The consideration and evaluation of potential external events such as severe weather, flooding, equipment lifting activities, etc. shall be applied to the Maintenance Risk Assessment when warranted by the potential for the external event."

Moreover, plant procedure ABN-907, "Acts of Nature," describes the operator actions to be taken in the event of severe weather and other acts of nature that may occur during any mode of operation. Specifically, the National Weather Service (NWS) has a continuous radio broadcast service of weather conditions in the Dallas-Fort Worth area. A receiver capable of receiving and decoding the NWS alert tone for severe weather notifications is monitored in the Control Room and Alternate Access Point for the issuance or cancellation of Severe Thunderstorm and Tornado Watches. Security personnel on duty in the Alternate Access Point will keep the Control Room informed of all watches or warnings issued or canceled by the NWS. Visual observations will be made by Security Officers and Safety Services personnel during the performance of their normal duties when a watch has been issued. The Control Room will be kept informed of visual observations regarding weather conditions by radio or telephone. Plant Equipment Operators are trained as SKYWARN spotters and may be utilized to determine weather severity.

In addition, plant procedure STA-629, "Switchyard Control," requires "Work should be scheduled to minimize the impact from grid loading, weather and worker conditions."

The following restriction will also be applied during the 30 day CT:

- Planned maintenance of a Startup Transformer will be scheduled during periods when seasonal weather conditions at CPSES have historically not been severe or threatening to offsite power. Times of peak tornado or

> thunderstorm frequency or likelihood of winter ice storms will be avoided. Times of optimum grid conditions will be considered in selecting the pre-planned maintenance window.
>
> The 30 day Completion Time may be used to perform corrective maintenance or to mitigate emergent conditions. If weather conditions deteriorate such that risk to the plant increases, the Startup Transformer will be restored to operable status if possible, or work will be either postponed or suspended, or compensatory measures will be initiated to reduce risk.

As shown in Table 3 of LAR 06-007 (TXX-07012), even without the reduction for weather conditions, removing a transformer from service for thirty days was not risk significant (CDF was less than 1E-06 and LERF was less than 1E-07). It is Case 3 of Table 3 that was used as the basis for the extended CT.

Case 4 (Table 3 of LAR 06-007) did not credit transformer recovery. It was also assumed that surveillance testing will be allowed on the Diesel Generator. This was accomplished by leaving the Diesel Generator test and maintenance at the original value. Therefore, no credit was taken for administratively controlling testing or maintenance of the Diesel Generator.

A sensitivity case was performed (Case 5 from Table 3 of LAR 06-007) to show the additional reduction in risk if weather is considered.

The following paragraphs are to provide some additional information on how the weather-centered LOOP considerations were applied.

The CT in LAR 06-007 did not require the reduction in weather-centered portion of the LOOP be credited in order to meet the regulatory guides' thresholds. This case shows that even in the event where unfavorable weather conditions are present during planned maintenance or for cases where adverse weather conditions and unplanned maintenance occur simultaneously, this CT extension is not risk significant.

The consideration for weather is based on historical data taken from the National Oceanic and Atmospheric Administration database. The data for CPSES was plotted based on the day of the year. From this graph it was evident that the April to June timeframe had the greatest probability of severe weather. It was concluded that if this work was performed during any other time of the year the weather centered portion of the LOOP could be reduced.

No credit was taken for transformer recovery. Also, it was assumed that when the surveillance testing is done on the Diesel Generator, the Diesel Generator is still available. The Diesel Generator meets the requirements of availability in accordance with the Maintenance Rule, (a)(4). During the surveillance there is a dedicated operator, a procedure for restoring the equipment to service, and the action is simple with a high certainty that the action will be completed. Therefore, the Diesel Generator remains available.

A sensitivity analysis was performed (Case 6 from Table 3 of LAR 06-007) to show the additional reduction in risk if weather is considered. CPSES is required as stated to consider the potential for severe weather when scheduling work.

Note that when either planned or unplanned maintenance is performed on the ST, if weather conditions deteriorate such that risk to the plant increases, the Startup Transformer will be restored to operable status if possible, or work will be either postponed or suspended, or compensatory measures will be initiated to reduce risk. Also, the proposed restrictions in response 2 would be applied in addition to the plant procedures to consider the potential for severe weather when scheduling work and operator actions as discussed above

D. **While the LOOP frequency is reduced for the analysis of the 30-day completion time (CT) period, it is not increased by a corresponding amount during the remainder of the year. Specifically, the frequency of severe weather would be greater in the high risk period of the year compared to an average annual value, and any deferred switchyard and other maintenance activities would be performed in the remainder of the year. Similarly, no testing or maintenance (other than diesel generator monthly operation) is assumed during the CT period, so all other testing and maintenance would occur during the remainder of the year. The licensee should justify its calculations or re-evaluate the risk impact addressing these issues.**

Response:

The question regarding deferred test and maintenance was addressed directly through the sensitivity analysis (Case 9) wherein the test and maintenance unavailability was increased to reflect the deferred test and maintenance. The test and maintenance unavailabilities were increased by 9%. This is a conservative approach since the test and maintenance unavailability includes both corrective and preventative maintenance as well as testing unavailability. The corrective maintenance is based on historical data and should not change significantly due to the CT. These revised values were used in a calculation to provide a new baseline for the remaining portion of the year (365-30=335days) as part of the sensitivity.

The impact of these items on the results will be discussed at the end of question 1.

For the specified 30 day CT period the weather conditions will be set per the historical data, but for the balance of the year conditions are an average of the historic data. The configuration risk management program is used to assess weather conditions during normal maintenance. Further sensitivities in response to this question were performed. The events which were removed as part of the 30 day CT were added back into the plant-centered LOOP to account for plant-centered events postponed that would now be performed during the remainder of the year. Therefore, a historical average for weather-centered probability is used for the remaining, portion of the year.

As stated in the response to question 1C, even without the reduction for weather conditions, taking a transformer out of service for thirty days was not risk significant in accordance with the applicable regulatory guides. Therefore the reduction for weather is unnecessary to meet the regulatory guide acceptance criteria. It is also assumed that should transformer work need to be performed the work in the switchyard would be administratively controlled.

E. **Since the normal plant configuration has two STs available for offsite power, the development of the nominal LOOP frequency for CPSES may have screened out industry events which involved failure of a single transformer or offsite source. Such events may have occurred in older plants without a redundant design or requirement, or during plant outages when a single offsite source was all that was available. Similarly, weather events which are spatial in impact (such as lightning strikes or tornadoes) may have been excluded based on the physical separation of the two CPSES STs, assuming that a similar weather event could not disable both STs. During the 30-day CT, the plant configuration is such that these previously excluded events would cause a LOOP. For example, failure of the aligned ST or circuit breakers connecting to the plant busses would now result in a LOOP, or a single lightning strike or tornado could disable the one ST. Further, these plant-centered events would not be immediately recoverable without repairs to the affected equipment. The licensee should discuss how such potential contributions to LOOP during the 30-day CT have been addressed in their risk analysis supporting this request.**

Response:

The industry events were reviewed in detail to determine which could be excluded for personnel actions in the switchyard. Part of this evaluation of industry events was to ensure that any industry event which could lead to a LOOP due to having one transformer out of service was included in the calculation of the new LOOP frequency.

All LOOP events that were previously excluded from the original LOOP calculations were reviewed again to see if the event was applicable to CPSES with the plant in the CT configuration. The resulting configuration used was one transformer being fed from one switchyard with multiple feeds to the switchyard. This resulted in an increase the LOOP frequency for the 30 day CT.

The impact of this item on the results will be discussed at the end of question 1.

F. A sensitivity analysis should be provided based on not reducing the LOOP frequency for plant-centered events in order to determine if there is over-reliance on programmatic activities to compensate for weakness in plant design (Regulatory Guide (RG) 1.177 Section 2.2.1).

Response:

Sensitivity Case 10 (see Table 1 below) was performed using a recalculated LOOP initiating event frequency only adjusted for the single ST plant configuration but not crediting administrative controls. The increase of Case 10 from Case 9, that did take credit for reduced plant-centered events due to administrative controls as well as accounting for the no test and maintenance and no switchyard work that would make the remaining ST unavailable, is approximately 1% (1E-07). This demonstrates that there is not an over reliance on administrative controls.

The PRA model has been created to include the actual switchyard design in enough detail to account for any design weakness. This includes modeling of the transformers, the major breakers, and the lines from the grid that feed the switchyard. The Individual Plant Examinations (IPE) did not reveal any plant vulnerabilities related to the switchyard.

Table 2 below was created to display the results of the sensitivities performed to answer questions 1B (Case 8), 1D (Case 9) and 1E (Case10). Each case is described below Table 1.

Table 1 Sensitivity Cases

Description	CDF	LERF
Baseline	9.30E-06	6.31E-07
Case 8	9.87E-06	6.51E-07
Case 9	1.27E-05	6.48E-07
Case 10	1.28E-05	6.51E-07

Baseline: The Probabilistic Risk Analysis (PRA) model quantified with test and maintenance (9.30E-06).

Case 8: The model quantified with the recalculated LOOP frequency plus the increase for the test and maintenance due to the 30 day CT as noted in question 1D.

Case 9: The model quantified with the recalculated LOOP noted in question 1E and the ST out of service.

Case 10: The model quantified with the recalculated LOOP only adjusted for the configuration (ST out of service) but not crediting administrative controls. This was performed to address the concerns in question 1F.

The ΔCore Damage Frequency (ΔCDF) and ΔLarge Early Release Frequency (ΔLERF) were calculated using the following formulas:

ΔCDF= ((Case 9 CDF*30/365) + (Case 8 CDF*335/365) – Baseline CDF
ΔLERF= ((Case 9 LERF*30/365) + (Case 8 LERF*335/365) – Baseline LERF

The Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) were calculated using the following formulas:

ICCDP= (Case 9 CDF – Baseline CDF) * 30/365

ICLERP= (Case 9 LERF – Baseline LERF) * 30/365

Table 2. Results

ΔCDF	ΔLERF	ICCDP	ICLERP
8.03E-07	**1.98E-08**	**2.79E-07**	**1.40E-09**

The above equations allow for calculation of the metrics required by RGs 1.174 and 1.177. The calculation has been modified to account for the different plant configurations and administrative controls to give a more representative reflection of the plant risk for the requested CT. As seen above the metrics meet the threshold requirements of both Regulatory Guides.

The following paragraphs are to provide some additional information on how work in the switchyard is performed.

Work in the switchyard is controlled procedurally by three different groups; Work Control, Switchyard Coordinator, and Operations. The Work Control group coordinates plant work by means of a weekly schedule. The Switchyard Coordinator is responsible for all work in the switchyard. The Coordinator ensures that the work being performed in the switchyard is coordinated with the plant and in particular with the Work Control group and Operations. Operations has the overall responsibility for plant configuration. Work in the switchyard is administratively controlled by the Shift Manager, Operations, who by plant procedure, STA-629 "Switchyard Control," has sole authority to grant access to the switchyard.

These three groups ensure that the work being performed onsite is administratively controlled. Based on the above controls which physically limit access to the switchyard this is not considered an optimistic program assumption. The final check is that work being performed in the plant is reviewed for risk implication by both the Work Control group and the Risk and Reliability group on a weekly basis.

2. The calculations of DCDF and DLERF effectively assume a single entry into the extended 30-day CT each year, but no such restrictions have been identified and the licensee specifically states they will use the 30-day CT for corrective maintenance if needed. The licensee has identified the recent maintenance history and its proposed 22-day preventive maintenance. The licensee is requested to justify that the assumption of one 30-day CT per year is conservative, or proposes appropriate restrictions on the use of the extended CT.

Response:

The work on the transformers is planned in advance due to the need to procure parts and services. The intent of this CT is to be used only for planned maintenance but should not preclude the use of the CT in the rare event there is a need to perform emergent work. A review of the maintenance rule data since 1999 shows no unplanned maintenance events for the STs in that period. The risk analysis has shown that this evolution is not risk significant. Therefore the use of this CT at anytime is consistent with other requests for extended CTs. Limiting use of the CT to only once per year would be overly restrictive relative to the guidance set forth in RGs 1.174 and RG 1.177 for risk informed applications.

During a planned maintenance outage of a Startup Transformer, maintenance and testing of the remaining offsite circuit will not be conducted if the maintenance and testing would make the remaining offsite circuit inoperable. With two offsite circuits inoperable, TS 3.8.1 Condition C requires one qualified circuits be restored to operable within 24 hours.

In addition, the CT will be used with the restrictions listed below:

- Before utilizing the 30 day Completion Time for planned maintenance of a Startup Transformer, the following provisions will be made:
  1. Service and support equipment will be pre-staged
  2. Replacement parts will be pre-staged
  3. Experienced personnel will be available to perform work
  4. Pre-job briefs will be conducted

- During the 30 day Completion Time when a Startup Transformer is inoperable, the monthly surveillance testing on the EDGs is allowed but the following equipment will not be removed from service:
  1. AC or DC electric power, electric system components, or electric equipment supplying the operating Startup Transformer
  2. Either train of the station service water system, components, or equipment
  3. The Turbine Driven Auxiliary Feedwater Pump and associated equipment and valves required for decay heat removal

- Planned maintenance of a Startup Transformer will be scheduled during periods when seasonal weather conditions at CPSES have historically not been severe or threatening to offsite power. Times of peak tornado or thunderstorm frequency or likelihood of winter ice storms will be avoided. Times of optimum grid conditions will be considered in selecting the pre-planned maintenance window.

  The 30 day Completion Time may be used to perform corrective maintenance or to mitigate emergent conditions. If weather conditions deteriorate such that risk to the plant increases, the Startup Transformer will be restored to operable status if possible, or work will be either postponed or suspended, or compensatory measures will be initiated to reduce risk.

- When utilizing the 30 day Completion Time for one inoperable Startup Transformer, no switchyard activity allowed that would increase the probability of loss of offsite power.

3. No common cause failure (CCF) mechanism has been postulated between the two STs, based on difference in design and voltage. However, the submittal also identified that both STs are "forced oil and air (FOA), 58.33 MVA transformers,...". This would seem to indicate that the transformers are the identical except for the specific location of the taps. It is further assumed that similar maintenance practices, procedures, and trained personnel would be applied to both STs. Finally, there may be other components subject to the proposed extended CT which may be subject to CCF, such as electrical breakers. RG 1.177 Section 2.3.3.1 and Appendix A Section A.1.3.2 identifies methods for quantitative evaluation of CCF when evaluating equipment unavailability due to corrective maintenance. The licensee is requested to more specifically identify design differences which justify not considering CCF between the transformers, and to justify that the risk evaluation for preventive maintenance is bounding for corrective maintenance involving other components subject to Limiting Condition for Operation (LCO) 3.8.1. Alternatively, the licensee may provide a revised risk analysis which evaluates corrective maintenance consistent with RG 1.177 Section A.1.3.2.

   Response:

The XST1 transformer is manufactured by General Electric transformer (138 kilo volt (kV)) with core form having a 138 kV high side and a 6.9 kV low side and is powered from the 138 kV switchyard. XST1 has a 35.0/46.67/58.3 MVA rating with OA/FA/FOA (Oil-Immersed/ Forced-Air-Cooled/ Oil-Immersed Forced-Oil-Cooled with Forced-Air Cooler). The XST2 transformer is manufactured by Westinghouse with shell form having a 345 kV high side and a 6.9 kV low side and is powered from the 345 kV switchyard. XST2 has a 35.0/46.67/58.3 MVA rating with OA/FOA/FOA. These transformers are sufficiently different such that common cause failures are unlikely.

CPSES TS define Operability as, "A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s)." Therefore, if ST supporting equipment is inoperable, then the associated ST is inoperable. The 30 day CT only addresses work on the transformers and assumes that no other work will be performed on the operating transformer if the work makes the remaining ST inoperable. The model already accounts for common cause failures of the onsite distribution breakers. All supporting equipment for the STs, other than circuit breakers, is included within the transformer boundaries and is not modeled separately in the PRA analysis.

4. The licensee is requested to provide the failure modes, assumed failure rates, exposure times, and failure probabilities associated with both STs, and the data source(s), including any plant-specific data, and calculation methods used to determine these parameters.

Response:

The failure modes are "fail during operation" and "unavailable due to maintenance." The exposure time for "fail during operation" is 24 hours with a failure rate of 1.43E-6 per hour and the failure probability is 3.43E-05. The unavailability due to maintenance is 2.04E-03 and is a point estimate based on a combination of preventive maintenance and corrective maintenance. The data source for failure mode of "fail during operation" was the Pickard, Lowe, and Garrick, Inc. 0500 (PL&G) database, "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants" Revision 0, July 1989 updated with plant data using the Bayesian method. The unavailability due to corrective maintenance was obtained from the PL&G database and was also updated with plant data using the Bayesian methods. The unavailability due to preventative maintenance was calculated using PL&G database. The values are the same for both transformers.

The plant has experience one ST failures which resulted in an unavailability for corrective maintenance of 6.8 hours. This was used in the Bayesian update of the transformer unavailability due to corrective maintenance probability.

The CPSES PRA models each component of the LOOP; weather-centered, plant-centered, and grid-centered. It also models grid blackout and consequential LOOP. The switchyards are modeled in detail and include the major components and the automatic switchover to the opposite plant. The plant-centered branch is composed of the initiating event (plant-centered event frequency discussed in question 1) and the individual component failures for the 24 hour mission time. This allows the analysis to be more detailed and specific.

5. **The licensee is requested to identify the specific version and date of the probabilistic risk assessment (PRA) model applied for the risk evaluations supporting the proposed change, and identify any plant changes (i.e., modifications, procedure revisions, or other items) not yet incorporated into the PRA model, including justification that such unincorporated changes do not adversely impact the stated risk impact.**

Response:

The revision of the PRA model being used for LAR 06-007 is Revision 3B dated January 2005. This model had no outstanding issues and had resolved all peer review comments. At the time of LAR 06-007 was issued, there were no outstanding plant changes affecting the model. The only significant change to the plant since the time of LAR 06-007 is the steam generator replacements in Unit 1. The model has been updated and LAR 06-007 was reviewed against the minor changes made to the PRA model. That review showed the changes to the PRA model were not risk significant and would not significantly affect LAR 06-007.

6. The licensee stated that the computation of incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) were per the definitions in RG 1.177, and identified specific equations used to perform the calculations. However, RG 1.177 uses the increase above the nominal baseline risk, including contributions from nominal expected equipment unavailability, while the licensee calculations specify the use of the baseline CDF without test or maintenance contributions included. The licensee is requested to clarify its calculation basis, which appears to be different than the specific RG 1.177 guidance.

Response:

The calculation for the ICCDP and ICLERP (see Table 1 above) used the baseline test and maintenance model. The ΔCDF and ΔLERF were calculated using the following formulas:

ΔCDF= ((Case 9 CDF*30/365) + (Case 8 CDF*335/365) – Baseline CDF

ΔLERF= ((Case 9 LERF*30/365) + (Case 8 LERF*335/365) – Baseline LERF

The ICCDP and ICLERP were calculated using the following formulas:

ICCDP= (Case 9 CDF – Baseline CDF) * 30/365

ICLERP= (Case 9 LERF – Baseline LERF) * 30/365

The Baseline is the PRA model quantified with test and maintenance. Case 8 is the model quantified with the recalculated LOOP frequency plus the increase of the existing test and maintenance to account for the deferred test and maintenance due to the CT. Case 2 is the model quantified with the recalculated LOOP which considered the CT configuration and administrative controls. This case restricted test and maintenance activities for the CT period except when testing the EDG.

The above equations allow for calculation of the metrics required by RGs 1.174 and 1.177. The calculation has been modified to account for the different plant configurations and administrative controls to give a more representative reflection of the plant risk for the requested CT. The Delta CDF and Delta LERF were both calculated using the test and maintenance model. This is consistent with the applicable regulatory guides.

7. **The cases analyzed assume that ST XST1 is removed from service, but no evaluations are provided for XST2. The licensee is requested to justify that the XST1 out-of-service case bounds the XST2 out-of-service case or to provide the appropriate evaluations of XST2.**

Response:

The case in which XST2 was out of service was analyzed and was found to have the smaller metrics of the two cases. Since XST1 gave the greater increase in the metrics of the two cases, it was used for the LAR 06-007. Unit one and two are sister plants (single PRA model is applicable to both Units) and both can be powered from either transformer. The difference is limited to the reliability of the switchyards providing power to the transformer. The case of XST1 powered from the 138 kV switchyard was chosen as the bounding configuration due to the smaller number of offsite feeds to the switchyard. So if the worse case, i.e., Unit one with XST1, met the regulatory requirements, as was seen in LAR 06-007 and the sensitivities performed in response to these RAIs, then Unit two would also meet the requirements for either transformer. This was done to simplify LAR 06-007.

8. The licensee's submittal Section 4.2.2 states that the CPSES PRA internal events model does not include contributions from internal floods, and that these events would be qualitatively evaluated. However, no qualitative evaluation of internal flooding events was provided. The licensee is requested to provide an evaluation of internal flooding events as they may relate to the risk impact of the proposed TS changes.

Response:

The transformers are located in the yard in the protected area. The transformers are outside and there is adequate drainage for any water which might get near the transformers. Also, there is no process piping near the transformers that could cause flooding. Therefore, neither ST can be impacted by any internal flood scenario. While in the 30 day CT configuration, there is no cable routing that could cause a loss of the feed from the transformer due to an internal flood scenario except in the switchgear rooms. The scenarios of the loss of a feed in the switchgear rooms are already accounted for in the internal flood. A flood in a switchgear room assumes loss of the switchgear regardless of how the switchgear is being fed. Therefore, the requested CT extension does not significantly impact the risks from internal floods.

9. The licensee's qualitative evaluation of external events including internal fires specifically considers events which may disable a single ST, but not events which would disable both STs or cause a LOOP. The staff agrees with this approach, provided that the scope of equipment includes not just the STs themselves, but all CPSES components which could be subject to TS 3.8.1 for offsite circuits, specifically cables and breakers which connect the ST output to the CPSES safety busses, as well as any instrumentation and control circuits which may affect the STs and breakers. This is especially important when addressing internal fires and floods which may only impact one plant safety train, but which may be able to cause a trip of the aligned ST. For example, if a fire or internal flood inside the plant can result in an electrical fault which trips the available ST, and if the consequences of such an event were determined acceptable due to the availability of the redundant ST, then such consequences may be greater than assumed when the redundant ST is unavailable under the proposed

extended CT. The licensee is requested to provide qualitative analyses which includes these additional components, and to address the internal fires and floods with regards to scenarios which may result in a trip of the aligned ST.

Response:

The affects of floods are discussed in question 8. The circuits associated with the transformers are located in similar areas (i.e., control room and cable spreading room) and therefore are not affected by the CT configuration. A flood of the control room or cable spreading room assumes loss of equipment in those areas including the transformer/offsite power associated circuitry.

Fire, in general, is the same as flood. The transformers are located outside and are not subject to internal fires. The external fires are already accounted for in the plant-centered initiating events. However, the cable routing is susceptible to fire unlike the internal flood assumption. Therefore, a fire along the cable route could cause a loss of the feed during the CT configuration resulting in a LOOP. To address this additional risk, the scenario that leads to core damage was analyzed. This analysis considered the fire initiating event, the loss of both EDGs and the failure of the turbine driven auxiliary feedwater pump (TWAFP) which, if left unmitigated, would eventually lead to core damage. The initiating event frequency was calculated by summing contributions from all the fire zones that the cables from either transformer transverse. This is a conservative calculation as only one transformer will be in service and the associated cables only transverse a small portion of any of the fire zones.

A screening analysis was performed for fire consideration of the proposed CT configuration to determine if a more detailed analysis was needed. If the screening analysis did not produce risk significant results further analysis was not necessary. No credit was taken in this screening analysis for automatic suppression or detection, for protective covering, or for operator actions or manual fire suppression. It should be noted that all the involved fire zones are frequently traveled and detection of any fire is very likely. The transformer is not considered recoverable for this screening analysis and no other equipment recovery or mitigating action was applied.

The cables for both transformers go through many of the same fire zones, but the cables for transformer XST2 (Unit 1 preferred transformer) go through more fire zones. For this reason XST2 is considered the worst case. The fire initiating frequencies for all the fire zones the XST2 cables were routed through were summed. As noted above, this is very conservative since the cable may only be routed through a small portion of the fire zone.

The summing of the initiating frequencies for these fire zones yielded an initiating event frequency of 2.47E-03 based on the 30 day CT. When combined with a loss of the diesel generators (common cause probability is 6E-04) and the failure of the turbine driven auxiliary feedwater pump (TDAFWP) (failure to operate probability is 2E-02), this leads to a cutset with a probability of 2.96E-08. The failures with the highest value failure mode were used for each event. In order to have core damage with a loss of site power, CPSES must have a failure of the diesel generators and a failure of the TDAFWP. This value shows that this screening analysis is not risk significant and therefore does not require further detailed evaluation. Therefore, it can be concluded that risk due to fire while in the CT configuration is not risk significant.

10. **The licensee's qualitative analysis of fires stated that the frequency of transformer fires is bounded to be no more than about 5% of the internal events LOOP frequency, and therefore stated that fire risk from transformer fires would not impact the conclusions of the risk analysis supporting the proposed change. However, this neglects the fact that a transformer fire would not be immediately recoverable, and comparison to the LOOP frequency for which the risk impact includes recovery probability may not be adequate to reach this conclusion. The licensee is requested to consider the impact of offsite power recovery capability following a transformer fire to confirm that the conclusions regarding the risk of such events is unchanged.**

Response:

The model does take into account the failure of the transformer during operation and this bounds the transformer fire. There are no recovery factors applied to the loss of a transformer, since the loss of a transformer event is already in the model and was not changed due to LAR 06-007. That is, the model accounts for loss of the transformer due to fire or any other cause. It should be noted that the transformers are inspected during the operator's rounds and any condition adverse to quality would be noted. Conditions that would lead to loss of the one operating transformer would be noticed and corrective actions taken. The impact of fire with regards to the 30 day CT configuration and the potential impact on risk is addressed in the response to question 9.

11. **The licensee's qualitative** analysis of high winds stated that a LOOP was assumed to occur. This is a conservative assumption for an average risk PRA model, since there may be events (such as tornados) which would impact a single offsite source such as the ST, especially if the two STs and their connecting cables into the plant are physically separated. However, such events are masked by the conservative assumption of a complete LOOP, and could be significant to the actual risk impact during the extended CT outage. The licensee stated that the frequency of a tornado-induced single ST failure was two orders of magnitude less than the internal events LOOP frequency, and therefore even if such events could occur and only impact one ST, the risk would not impact the conclusions of the risk analysis supporting the proposed change. As noted in RAI 10, this neglects the fact that such events are not immediately recoverable due to damage to the ST. The licensee is requested to consider the potential for high wind events such as tornadoes accounting for the physical separation of the STs and supporting components, as well as the impact of offsite power recovery capability following a high wind event, to confirm that the conclusions regarding the risk of such events is unchanged.

Response:

The high wind analysis for the Individual Plant Examination External Events (IPEEE) did not consider loss of the station transformers by themselves but rather consider this with the loss of offsite power. The loss of offsite power calculation included events from high winds. A screening analysis was performed for high winds consideration of the proposed CT configuration to determine if a more detailed analysis was needed. If the screening analysis did not produce risk significant results further analysis was not necessary. The high wind screening analysis assumed that only the transformer which was in service was lost for the proposed CT configuration. In most cases, high wind would cause a LOOP in addition to the loss of the transformer and this event was considered in the IPEEE. Also approximately 24% of events used in the loss of offsite weather centered calculation were due to high winds. The transformer is not considered recoverable for this screening analysis and no other equipment recovery or mitigating action was applied.

Using the methodology of the IPEEE, the transformers are considered small targets. This was determined based on the surface area of the transformer (180 square feet) compared to an IPEEE large target which is greater than 1000 square feet. This leads to an initiating event frequency of 2.16E-02 based on a small target missile strike frequency and the 30 day CT. When combined with a loss of the diesel generators (common cause probability is 6E-04) and the failure of the turbine driven auxiliary feedwater pump (TDAFWP) (failure to operate probability is 2E-02), this leads to a cutset with a probability of 2.6E-07. The failures with the highest value failure mode were used for each event. In order for a loss of offsite power event to result in core damage, CPSES must have a failure of the diesel generators and a failure of the TDAFWP. The cutset value of 2.6E-07 shows that this screening analysis is not risk significant and therefore does not require a detailed evaluation. Consequently, it can be concluded that risk due to high winds while in the CT configuration is not risk significant.

The external events considerations were evaluated as screening analyses with very conservative assumptions using a qualitative evaluation of each event. In the overview (Section 4.2.2 of LAR 06-007) it is stated, "The conclusion of this qualitative assessment is that external events have only a minor impact on the results of the internal events evaluation." This along with the statement in each specific external event, that the individual event "does not impact the conclusions of this analysis" addressed the impact on the conclusions of the risk assessment.

12. The licensee's qualitative evaluations of seismic events, fires, and high winds states properly that these events "do not impact the conclusions of this analysis." However, with regards to external floods and other external events, the concluding statements are not as specific, addressing "contribution to total CDF", "not account for a significant risk contribution in any of the CPSES IPEEE submittals", etc. The licensee is requested to definitively state their conclusions regarding external floods and other external events with regards to their impact on the conclusions of the risk analysis supporting this proposed change.

Response:

As discussed in the previous question, internal flood and fire have been addressed. The remainder of the external events is addressed below.

The IPEEE is the basis for review of the impact of a seismic event and other external events. The plant was reviewed for any changes which might effect the assumptions made in the IPEEE. No plant changes were found with respect to the transformers that would effect the assumptions made in the IPEEE. So the conclusions and methodology of the IPEEE remain valid.

A screening analysis was performed for seismic consideration of the proposed CT configuration to determine if a more detailed analysis was needed. If the screening analysis did not produce risk significant results, further analysis was not necessary. The seismic screening analysis assumed that only the transformer which was in service was lost for the proposed CT configuration. The risk of a transformer becoming unavailable due to a seismic event is very small since the frequency of such seismic events is approximately two orders of magnitude less than the internal events LOOP frequency (3E-04) and the increased fault exposure time is a fraction of the year (30 days per year). When combined with a loss of the diesel generators (common cause probability is 6E-04) and a failure of the TDAFWP (failure to operate probability is 2E-02), this leads to a cutset with a probability of 3.6E-09. The failures with the highest value failure mode were used for each event. In order for a loss of site power event to result in core damage, CPSES must have a failure of the diesel generators and a failure of the TDAFWP. This value shows that this screening analysis is not risk significant and therefore does not require a detailed evaluation. Therefore, it can be concluded that risk due to seismic events while in the 30 day CT configuration is not risk significant.

Other external events include transportation, nearby facility accidents, and the other external events listed in Table 4.1 of NUREG-1742, "Perspectives Gained From the Individual Plant Examination External Events (IPEEE) Program." As concluded in the NUREG, these events do not account for a significant risk contribution in any of the IPEEE submittals. This conclusion is consistent with the conclusions and insights from the CPSES IPEEE. Thus from an evaluation of external floods and other external events for CPSES for this extended CT, it is concluded that these events do not impact the conclusions of this analysis. Therefore these events were not considered to be risk significant. Since these external events were not risk significant no sensitivity studies were required to be performed.

13. The licensee's submittal did not identify if the risk analyses provided point estimates of the mean or actual means, nor was there any discussion of uncertainty analyses to support the calculations. The licensee is requested to address PRA model uncertainty using the guidance of RG 1.174 Section 2.2.5.

Response:

The risk analysis uses point estimates of the mean from the PL&G database which are Bayesian updated if plant data is available and appropriate.

Two sensitivity analyses (Case 2 and Case 3 of Table 3 in TXX-07012) were performed with the Startup transformer out of service. These analyses used the test and maintenance model and were run for Unit 1 and 2. There were no adjustments made for any compensatory actions. The results showed that the Unit 1 sensitivity met the requirement for ΔCDF (less than 1E-06) but did not meet the requirement for the ICCDP. The ICCDP requirement is 5E-07 and the actual ICCDP for Unit 1 with the Startup Transformer was 7.47E-07. The Unit 2 analysis met the requirements for ΔCDF and ICCDP. These sensitivity analyses are in agreement with the submittal which showed that when compensatory actions are taken, the RG criteria were met. Furthermore, RG 1.177 Section 2.3.5 states that TS changes have shown that the risk resulting from TS CT changes is relatively insensitive to uncertainties. This sensitivity was used to bound the CT.

14. Section 4.1 of the licensee's submittal identifies administrative controls which would be applicable to the extended CT. In addition, Section 4.2.3 identifies plant equipment and activities which, if unavailable simultaneous with the CT, would likely result in a high risk configuration. The staff has additional questions regarding these portions of the submittal:

A. The licensee's submittal does not specifically identify whether these statements represent commitments. The staff notes that the licensee's risk analysis assumes no other testing or maintenance activities on other plant equipment (other than monthly Emergency Diesel Generator (EDG) testing) and assumes no activities which would increase the likelihood of a loss of the remaining operable offsite

circuit. The licensee is requested to clarify their intent with regards to the RG 1.177 tier two portion of their request.

Response:

CPSES has a Configuration Risk Management program which has the characteristics of the Model Configuration Risk Management Program described in RG 1.177 and which was previously approved for risk informed Technical Specifications. Its description has been incorporated into plant Technical Specifications (TS 5.5.18). In addition, CPSES has committed to NUMARC 93-01, "Industry Guideline For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants."

Currently CPSES uses the Safety Monitor software to perform online risk assessment. All PRA components are represented in Safety Monitor with the ability to take one or multiple components out of service. After the activities have been added (i.e., component taken out of service) the model is re-quantified and the CDF and LERF are calculated. The risk is then compared to preset values. Colors are used for the preset values based on the risk. As the risk is increased the requirement for management approval is raised. External events are evaluated qualitatively to determine their impact on the configuration risk.

This process is performed for all activities that affect a PRA component, initiating event, or recovery. The Work Control Group uses the weekly schedule to calculate the plant risk for the week on an activity basis. The proposed CT would be planned and added to the weekly schedule. The risk for the activity would be calculated with the weekly schedule. The weekly risk assessment will be reviewed and the appropriate management approval will be obtained if required.

The process is the same for emergent activities. The risk is assessed prior to the emergent activity being worked. The risk is calculated and scheduled activities may be moved to a later date or equipment put back in service to ensure that the risk is acceptable. Again the risk will be reviewed and appropriate management approval will be obtained if required.

The above process meets the requirement of RG 1.177 Section 2.3.7.

B. The staff notes that the section 4.1 administrative controls item 2 and 3 are worded subtly different; specifically, "weather conditions must be conducive to perform planned maintenance," and "offsite power supply and switchyard conditions must be conducive to perform maintenance". The licensee is requested to clarify the intent, if any, of the use and omission of the word "planned".

Response:

The use of the word "planned" was intentional on Page 15 of Attachment 1. The description of the administrative controls in INSERT B of Attachment 3 should have been the same as the administrative controls on Page 15 of Attachment 1. Attachment 2 and 3 of this document will replace Attachment 3 Page 5 of 5 and Attachment 5 Page 2 of 3 to TXX-07012, respectively.

C. **Section 4.1 states "switchyard access will be monitored and controlled per procedures". It is not clear that this represents any unique administrative control, since switchyard access should normally be so monitored and controlled using approved plant procedures. Further, the proposed changes specifically deal with repairs to components in the switchyard (the ST), when access to the switchyard may be greater than normal to facilitate the maintenance and repair activities. The licensee is requested to clarify the intent of this administrative control, especially in view of the fact that the risk analysis relies upon prohibition of plant-centered LOOP events due to switchyard maintenance activities.**

Response:

The startup transformers XST1 and XST2 are physically located in the owners protected area and not in the switchyard.

Work in the switchyard is controlled procedurally by Work Control, the Switchyard Coordinator, and Operations. The Work Control group coordinates plant work by means of a weekly schedule. The Switchyard Coordinator is responsible for all work in the switchyard. The Coordinator ensures that the work being performed in the switchyard is coordinated with the plant and in particular with the Work Control group and Operations. Operations has the overall responsibility for plant configuration and any work being performed is reviewed and approved by Operations. Work in the switchyard is administratively controlled by the Shift Manager of Operations who, by plant procedure STA-629, has sole authority to grant access to the switchyard.

These three groups ensure that the work being performed onsite is administratively controlled. Based on the above noted controls which physically limit access to the switchyard, this is not considered optimistic program assumptions. The final check is that the work being performed in the plant is reviewed for risk implications by both the Work Control group and the Risk and Reliability group on a weekly basis.

CPSES has a Configuration Risk Management program which has the characteristics of the Model Configuration Risk Management Program described in RG 1.177 and which was previously approved for risk informed Technical Specifications. Its description has been incorporated into plant Technical Specifications (TS 5.5.18). In addition, CPSES has committed to NUMARC 93-01, "Industry Guideline For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants."

Currently CPSES uses the Safety Monitor software to perform Configuration Risk Management Program assessment. All PRA components are represented in the Safety Monitor with the ability to take one or multiple components out of service. After the activities have been added (i.e., component taken out of service) the model is re-quantified and the CDF and LERF are re-calculated. The risk is then compared to preset values. Colors are used for the preset values based on the risk. As the risk is increased the requirement for management approval is raised. External events are evaluated qualitatively to determine their impact on the configuration risk.

This process is performed for all activities that affect a PRA component, initiating event, or recovery. The Work Control Group uses the weekly schedule to calculate the plant risk for the week on an activity basis. The proposed CT would be planned and added to the weekly schedule. The risk for the activity would be calculated with the weekly schedule. The weekly risk assessment will be reviewed and the appropriate management approval will be obtained if required.

The process is the same for emergent activities. The risk is assessed prior to the emergent activity being worked. The risk is calculated and scheduled activities may be moved to a later date or equipment put back in service to ensure that the risk is acceptable. Again the risk will be reviewed and appropriate management approval will be obtained if required.

The above process meets the requirement of RG 1.177 Section 2.3.7.

D. **Section 4.2.3 does not explicitly identify that the potential high risk configurations would be prohibited, consistent with the assumptions of the risk analysis, during the extended CT. The licensee is requested to clarify the intent of identifying these configurations.**

Response:

Section 4.2.3 explicitly identifies components that become risk significant when the transformer is taken out of service for the extended CT.

During the 30 day Completion Time when a Startup Transformer is inoperable, the monthly surveillance testing on the EDGs is allowed but the following equipment will not to be removed from service:

1. AC or DC electric power, electric system components, or electric equipment feeding the operating transformer
2. Either train of the station service water system, components, or equipment
3. The Turbine Driven Auxiliary Feedwater Pump and the associated equipment and valves required for decay heat removal

In addition, all plant test and maintenance activities affecting safety-related structures, systems, or components will be scheduled using the CRMP methodology and plant procedures.

15. RG 1.177 Section 2.3.7 describes various attributes of contemporaneous configuration control and the CRMP which can support risk-informed decision making. Certain aspects of the licensee's program have not been adequately described to assure that the guidance of RG 1.177 is met. Specifically, the licensee only states that added or emergent activities, or activities which have slipped from the scheduled completion time, are "addressed". RG 1.77 Section 2.3.7.1 requires specific descriptions to be provided, as to their capability to perform contemporaneous assessment of overall plant safety impact of proposed plant configurations, how the tools or other processes are used to ensure risk-significant configurations are not entered, and that appropriate actions will be taken when unforeseen events put the plant in a risk-significant configuration. Further, it identifies four key components of the CRMP, which have not been addressed by the licensee. The licensee is requested to confirm how their CRMP conforms to the RG 1.177 Section 2.3.7 guidance.

Response:

CPSES has a Configuration Risk Management Program which has the characteristics of the

Model Configuration Risk Management Program described in RG 1.177 and which was previously approved for risk informed Technical Specifications. Its description has been incorporated into the plant Technical Specifications (TS 5.5.18). In addition, CPSES has committed to NUMARC 93-01, "Industry Guideline For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants."

Currently CPSES uses the Safety Monitor software to perform online risk assessment. All PRA components are represented in the Safety Monitor with the ability to take one or multiple components out of service. After the activities have been added (i.e., component taken out of service) the model is re-quantified and the CDF and LERF are re-calculated. The risk is then compared to preset values. Colors are used for the preset values based on the risk. As the risk is increased the requirement for management approval is raised. External events are evaluated qualitatively to determine their impact on the configuration risk.

This process is performed for all activities that affect a PRA component, initiating event or recovery. The Work Control Group uses the weekly schedule to calculate the plant risk for the week on an activity basis. The proposed CT would be planned and added to the weekly schedule. The risk for the activity would be calculated with the weekly schedule. The weekly risk assessment will be reviewed and the appropriate management approval will be obtained if required.

The process is the same for emergent activities. The risk is assessed prior to the emergent activity being worked. The risk is calculated and scheduled activities may be moved to a later date or equipment put back in service to ensure that the risk is acceptable. Again the risk will be reviewed and appropriate management approval will be obtained if required.

Furthermore, the proposed restrictions discussed in response 2 will be applied when using the 30 day CT.

The above process meets the requirement of RG 1.177 Section 2.3.7.

16. The licensee has submitted a proposed change to extend the CT for LCO 3.8.1 with regards to one inoperable EDG from 72 hours to 14 days. The staff requests clarification of certain aspects of the proposed EDG change which may impact the proposed changes for the offsite circuits.

A. The licensee has not discussed the alternate AC power source (AACPS) which is an integral part of the proposed EDG CT extension basis. It would seem that the AACPS would provide similar benefits during the offsite circuit extended CT. The licensee is requested to discuss the potential safety benefit of the AACPS with regards to this proposed change, and whether an AACPS should be required whenever the extended CT is in effect.

Response:

The license amendment requests for the diesel generators (DGs) Completion Time extension and the STs Completion Time extension are stand alone, independent requests and are not related to each other. These license amendments affect different TS 3.8.1 Conditions and components and the respective extended CTs can not be entered simultaneously. The ST LAR affects Condition A while the DG LAR affects Condition B. CPSES is not requesting to extend the CT for Condition D which requires 12 hours to restore a DG or a ST to operable status given one required offsite circuit and one diesel generator is inoperable or be in MODE 5 or lower. The proposed DG and ST CTs can not and will not be invoked simultaneously. There is no regulatory requirement to provide an alternate AC power source. In addition, the risk analysis did not take credit for an AACPS nor is it indicated in the risk analysis that an AACPS is required.

B. **The second CT of LCO 3.8.1 applicable to contiguous application of the actions of the TS 3.8.1 is proposed to be increased from 6 days to 33 days in this amendment request, and from 6 days to 17 days for the EDG request. The licensee is requested to identify the proposed final CT. The staff also notes that TSTF-439-A eliminated this second CT, and the licensee may want to consider implementation of this TSTF along with these amendment requests.**

Response:

LAR 06-012 was submitted to the NRC on December 19, 2006 for approval. This LAR was based on TSTF-439-A to eliminate the second CT, but has yet to be approved. If the amendment is approved before the approval of the DG or ST CT amendments, the DG and ST LARs will be modified as appropriate.

The ST and DG amendment requests were written independent of each other and if either amendment is approved before the other, then that amendment will reflect the correct CT.

If these two amendments are approved simultaneously, or one after the other and before LAR 06-012, the combined CTs will be as described below.

Required Action A.3 would be renumbered as A.3.1 and A.3.2 and these two actions would have a conditional "OR" statement between them. Required Action A.3.1, "Restore required offsite circuit to OPERABLE status" would have a Completion Time of "30 days AND 33 days from discovery of failure to meet LCO." Required Action A.3.2, "Restore required offsite circuit to OPERABLE status" would have a Completion Time of "30 days AND 44 days from discovery of failure to meet LCO due to an inoperable DG with AACPS available."

Required Action B.4 would be renumbered as B.4.1 and B.4.2 and these two actions would also have a conditional "OR" statement between them. Required Action B.4.1, "Restore DG to OPERABLE status" would have a Completion Time of "72 hours AND 33 days from discovery of failure to meet LCO." Required Action B.4.2, "Restore DG to OPERABLE status" would have a Completion Time of "14 days AND 44 days from discovery of failure to meet LCO."

C. Because these two requests are directly related to AC power sources, the staff considers them to be a combined change request as defined by RG 1.174 Sections 2.1.1 and 2.1.2. The licensee is requested to submit the additional information identified in RG 1.174 with regards to the synergistic impacts of the proposed changes.

Response:

The license amendment requests for the diesel generators (DGs) Completion Time extension and the STs Completion Time extension are stand alone, independent requests and are not related to each other. These license amendments affect different TS 3.8.1 Conditions and components and the respective extended CTs can not be entered simultaneously. The ST LAR affects Condition A while the DG LAR affects Condition B. CPSES is not requesting to extend the CT for Condition D which requires 12 hours to restore a DG or a ST to operable status given one required offsite circuit and one diesel generator is inoperable or be in MODE 5 or lower. The proposed DG and ST CTs can not and will not be invoked simultaneously. There is no regulatory requirement to provide an AACPS. In additions, the risk analysis did not take credit for an AACPS nor is it indicated in the risk analysis that an AACPS is required.

It is our interpretation that each Technical Specification Condition and its Required Action can be risk informed and that each, on its own merit, can be implemented when shown to meet the required metrics. Whereas these are both directly related to AC power sources, they are nevertheless two separate Technical Specifications Conditions. These CTs will be independently administered. Thus, we see no synergistic effects that have not already been addressed.

With regard to cumulative effects of several extended CTs, we believe this is adequately addressed by the change metrics themselves. Since each change metric (e.g., delta CDF) is by design a small fraction of the base metric (e.g., CDF), the regulatory guides provide opportunity for numerous risk informed applications to be implemented without an unacceptable increase in overall risk.

17. The licensee has not identified whether the CPSES model credits any equipment repairs relevant to the proposed change, i.e., for the ST. The licensee is requested to identify and justify any such credit taken in the risk analyses supporting this change.

Response:

The CPSES model does not credit any equipment repairs relevant to the proposed change. The transformers and their associated equipment are not recovered if they fail. No credit was taken for recovery of equipment that supports the operating ST.

18. The CPSES FSAR Section 8.2.1 identifies the availability of a spare ST. Specifically, the FSAR states the following:

The spare startup transformer, XST1/2 with dual primary windings (345-kV and 138-kV), is stored in a dedicated location under the 345-kV line to XST2 (refer to Figure 8.2-1). This transformer can be energized from the 345-kV line by closing a normally open motor-operated air switch, or it can be physically moved and connected to the 138-kV line to XST1 if required. This transformer is provided to prevent an extended interruption of offsite power in case of failure of any startup transformer.

The staff interprets this to mean that prompt energization of the spare ST (via motor-operated switch) is available to backup XST2. Therefore, it is not clear why the spare is not used to replace a permanent transformer during performance of extended preventive maintenance, consistent with the CPSES FSAR. The licensee is requested to discuss the use of the spare ST to avoid the need for an extended CT for preventive maintenance. If the spare ST is not immediately available, the response should discuss the basis for the

statement in FSAR Section 8.2.1, and should identify the time required to place the spare ST in service, including swapping from the permanent ST to the spare ST within the existing CT of LCO 3.8.1.

Response:

To place the spare ST into service from its existing location for XST2 would require the running of cables from the low side of the spare to the 6.9 kV connections on the low side of XST2 after disconnecting XST2 and working the cable connections. Problems exist with trying to run cabling in that the cable introduces impedance differences which are not tolerable. Hence, the spare transformer would need to be physically relocated. The details of how this is performed are captured in Maintenance Guideline 37, "Start-up and Service Transformer Failure Recovery." Within this guideline, the references to the logic diagrams, PX schedules, and design change documents are given to allow for quick access to the steps need to replace either of the STs. Also, the mobilization steps necessary for successful removal and installation are detailed. The approximate time frame for the removal of the damaged ST and installation of XST1/2 is 18 days working 24/7 and with no weather delays.

In order to clarify the FSAR, the following change has been approved and will be included in the next Amendment of the FSAR:

"~~The~~ A spare startup transformer, XST1/2 with dual primary windings (345-kV and 138-kV), is stored in a dedicated location under the 345-kV line to XST2 (refer to Figure 8.2-1). This transformer ~~can be used~~ must be physically relocated to replace XST2 or XST1 if required. This transformer is provided to prevent an extended interruption of offsite power in case of failure of any startup transformer."

19. **Assuming a single failure of the remaining offsite power circuit when the preferred offsite power circuit is removed from service, in accordance with General Design Criteria 17 of Appendix A in 10 CFR Part 50, provide assurance that the specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary will not be exceeded.**

Response:

As written in CPSES FSAR 3.1.2.8, "The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents."

The CPSES offsite power system, in case the onsite power system is not functioning, has sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The GDC invoke single failure criteria only for onsite power systems by stating that:

> "The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure."

Single failure criteria are not applicable to the offsite power system. However, GDC 17 requires that:

> "Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained."

The CPSES design fully complies with these requirements. The offsite electrical power system provides required independence and redundancy to ensure an available source of power to the safety-related loads. Upon loss of the preferred power source to any 6.9 kV Class 1E bus, the alternate power source is automatically connected to the bus. Loss of both offsite power sources to any 6.9 kV Class 1E bus, although highly unlikely, results in the diesel generator providing power to the Class 1E bus.

20. Describe the capability, capacity, and design function of spare transformer XST ½. If applicable, describe the procedures for placing XST ½ in service and the associated length-of-time for completing this action.

Response:

Transformer XST1/2 is a dual rating transformer. That is, transformer XST1/2 is capable of accepting 345 kV or 138 kV at the high-side. Transformer XST1/2 also has 2 low side windings (6.9 kV) for connection to the safety buses. By accepting either 345 kV or 138 kV on the high-side, XST1/2 can be used in either application, that is, as XST1 (supplied from 138 kV yard) or as XST2 (supplied from the 345 kV yard).

The MVA rating of XST1/2 is 35.0/46.67/58.33 and Class OA/FA/FOA.

The location of Transformer XST1/2 is for storage only. Use of XST1/2 as either XST1 or XST2 will require the removal of either XST1 or XST2 and the installation of XST1/2 in the removed transformer's place. The details of how this is performed are captured in Maintenance Guideline 37, "Start-up and Service Transformer Failure Recovery." Within this guideline, the references to the logic diagrams, PX schedules and design change documents are given to allow for quick access to the steps need to replace either of the Startup transformers. Also, the mobilization steps necessary for successful removal and installation are detailed. The approximate time frame for the removal of the damaged Startup transformer and installation of XST1/2 is 18 days working 24/7 and with no weather delays.

In order to clarify the FSAR, the following change has been approved and will be included in the next Amendment of the FSAR:

~~The~~ A spare startup transformer, XST1/2 with dual primary windings (345-kV and 138-kV), is stored in a dedicated location under the 345-kV line to XST2 (refer to Figure 8.2-1). This transformer ~~can be used~~ must be physically relocated to replace XST2 or XST1 if required. This transformer is provided to prevent an extended interruption of offsite power in case of failure of any startup transformer.

21. **Describe the methodology used for determining that weather, offsite power supply, and switchyard conditions are conducive to perform maintenance on the offsite circuits for a 30-day period.**

Response:

The following discussion provides CPSES methodology concerning weather and maintenance on the STs:

> CPSES is required by plant procedures to consider the potential for severe weather when scheduling work. Specifically, plant procedures STA-604 "Configuration Risk Management and Work Scheduling" and WCI-203, "Weekly Surveillance/Work Scheduling" require "The consideration and evaluation of potential external events such as severe weather, flooding, equipment lifting activities, etc. shall be applied to the Maintenance Risk Assessment when warranted by the potential for the external event.
>
> Moreover, plant procedure ABN-907, "Acts of Nature," describes the operator actions to be taken in the event of severe weather and other acts of nature that may occur during any mode of operation. Specifically, the National Weather Service (NWS) has a continuous radio broadcast service of weather conditions in the Dallas-Fort Worth area. A receiver capable of receiving and decoding the NWS alert tone for severe weather notifications is monitored in the Control Room and Alternate Access Point for the issuance or cancellation of Severe Thunderstorm and Tornado Watches. Security personnel on duty in the Alternate Access Point will keep the Control Room informed of all watches or warnings issued or canceled by the NWS. Visual observations will be made by Security Officers and Safety Services personnel during the performance of their normal duties when a watch has been issued. The Control Room will be kept informed of visual observations regarding weather conditions by radio or telephone. Plant Equipment Operators are trained as SKYWARN spotters and may be utilized to determine weather severity.
>
> In addition, plant procedure STA-629, "Switchyard Control," requires work to be scheduled to minimize the impact of weather and worker conditions."
>
> The following restriction will also be applied during the 30 day CT:
>
> - Planned maintenance of a Startup Transformer will be scheduled during periods when seasonal weather conditions at CPSES have historically not been severe or threatening to offsite power. Times of peak tornado or thunderstorm frequency or likelihood of winter ice storms will be avoided. Times of optimum grid conditions will be considered in selecting the pre-planned maintenance window.

The 30 day Completion Time may be used to perform corrective maintenance or to mitigate emergent conditions. If weather conditions deteriorate such that risk to the plant increases, the Startup Transformer will be restored to operable status if possible, or work will be either postponed or suspended, or compensatory measures will be initiated to reduce risk.

The following discussion provides CPSES methodology concerning offsite power, switchyard conditions, and maintenance on the STs:

Currently methodologies exist in plant procedures for determining offsite power and switchyard conditions to insure switchyard activities and conditions are monitored and controlled during all maintenance activities.
In particular, STA-629 requires that during maintenance activities on the STs, the following controls should be implemented:

- All activity in the switchyards will be closely monitored and controlled. Switchyard posting and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

- Work should be scheduled to minimize the impact from grid loading, weather and worker conditions.

Per STA-629, the Switchyard Coordinator is notified 35 days prior to any scheduled corrective maintenance, preventive maintenance or testing on any equipment located within the 138kV switchyard, 345kV switchyard or affecting the incoming transmission lines connected to the switchyard by Oncor, previously known as TXU Electric Delivery. Additionally, the Switchyard Coordinator will notify Transmission Grid Operations 35 days prior to any scheduled corrective maintenance, preventive maintenance or any testing that could impact grid operations (i.e., ST 30 day CT). Emergent conditions are also communicated between Oncor and CPSES. Therefore, offsite power conditions which are communicated between Oncor and CPSES are considered when scheduling maintenance.

Importantly, STA-629 Attachment 8.F, "Communication Protocol," establishes guidelines for notifications to CPSES. Grid notifications to CPSES are agreed upon by ERCOT and Oncor and are outlined in this Attachment. In addition, the Attachment contains the requirement that upon unavailability of both ERCOT and TGC state estimator/contingency analyses programs, Oncor will notify the CPSES Control Room of the status and whether studies indicate CPSES switchyard voltages can be maintained per this attachment. Any normal Transmission scheduled maintenance that may affect power to or from CPSES switchyards is communicated to CPSES. Oncor will notify CPSES of any emergent issue that may affect the integrity of power to or from both CPSES switchyards including any forced outages of any transmission equipment directly connected to the CPSES switchyards. Oncor shall notify CPSES if the established operating voltage levels can not be or are expected not to be maintained for more than 30 minutes.

Attachment 8.H to STA-629, "CPSES Offsite Power System Performance Characteristics," defines CPSES' operating limits agreed upon by Oncor and ERCOT. Planning studies are done on a yearly basis and the necessary actions are taken, if needed, to assure that the voltage at the CPSES switchyards remain in the predefined limits. In this agreement Oncor shall avoid maintenance activities with an associated high likelihood of contingencies that could adversely impact CPSES switchyards voltage. When such activities are necessary, those will be discussed in advance with CPSES. Unavailability of any of the transmission lines tied to the CPSES switchyard shall be coordinated with CPSES (for planned activities) and communicated to CPSES (for unplanned events).

Attachment 8.J, "Switchyard Work Description," defines the guidelines of expected work activities and controls in the switchyard (i.e., procedures, human performance tools, and safety).

In addition, the following proposed restriction will be applied during the 30 day CT:

- When utilizing the 30 day Completion Time for one inoperable Startup Transformer, no switchyard activity that would increase the probability of loss of offsite power will be allowed.

In addition to procedural requirements, CPSES has a Configuration Risk Management Program which has the characteristics of the Model Configuration Risk Management Program described in RG 1.177 and which was previously approved for risk informed Technical Specifications. Its description has been incorporated into the plant Technical Specifications (TS 5.5.18). In addition, CPSES has committed to NUMARC 93-01, "Industry Guideline For Monitoring The Effectiveness Of Maintenance At Nuclear Power Plants."

Currently CPSES uses the Safety Monitor software to perform online risk assessment. All PRA components are represented in the Safety Monitor with the ability to take one or multiple components out of service. After the activities have been added (i.e., component taken out of service) the model is re-quantified and the CDF and LERF are re-calculated. The risk is then compared to preset values. Colors are used for the preset values based on the risk. As the risk is increased the requirement for management approval is raised. External events are evaluated qualitatively to determine their impact on the configuration risk.

This process is performed for all activities that affect a PRA component, initiating event or recovery. The Work Control Group uses the weekly schedule to calculate the plant risk for the week on an activity basis. The proposed CT would be planned and added to the weekly schedule. The risk for the activity would be calculated with the weekly schedule. The weekly risk assessment will be reviewed and the appropriate management approval will be obtained required.

The process is the same for emergent activities. The risk is assessed prior to the emergent activity being worked. The risk is calculated and scheduled activities may be moved to a later date or equipment put back in service to ensure that the risk is acceptable. Again the risk will be reviewed and appropriate management approval will be obtained if required.

In addition, the following proposed restriction will be applied during the 30 day CT:

- Before utilizing the 30 day Completion Time for planned maintenance of a Startup Transformer, the following provisions will be made:
  1. Service and support equipment will be pre-staged
  2. Replacement parts will be pre-staged
  3. Experienced personnel will be available to perform work
  4. Pre-job briefs will be conducted

- During the 30 day Completion Time when a Startup Transformer is inoperable, the monthly surveillance testing on the EDGs is allowed but the following equipment will not be removed from service:
  1. AC or DC electric power, electric system components, or electric equipment supplying the operating Startup Transformer
  2. Either train of the station service water system, components, or equipment
  3. The Turbine Driven Auxiliary Feedwater Pump and associated equipment and valves required for decay heat removal

ATTACHMENT 2 to TXX-07109

REVISED TECHNICAL SPECIFICATIONS BASES INSERTS PAGE (MARK UP)
(FOR INFORMATION ONLY)

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INSERT A

In Condition A, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. With an offsite circuit inoperable, the inoperable offsite circuit must be restored to OPERABLE status within the applicable, specified Completion Time.

INSERT B

The 30 day Completion Time is based on a plant specific risk analysis performed to establish the out of service time.

The following administrative controls will be applicable upon entry into plant conditions which rely on the extended CT.

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).

2. Weather conditions must be conducive to perform planned maintenance on the offsite circuits.

3. The offsite power supply and switchyard conditions must be conducive to perform maintenance on the offsite circuits.

4. Switchyard access must be monitored and controlled per procedures.

INSERT C

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.

ATTACHMENT 3 to TXX-07109

REVISED RETYPED TECHNICAL SPECIFICATIONS BASES PAGE
(For Information Only)

Page B 3.8-8

ACTIONS (continued)

A.3

In Condition A, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. With an offsite circuit inoperable, the inoperable offsite circuit must be restored to OPERABLE status within the applicable, specified Completion Time.

The 30 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The 30 day Completion Time is based on a plant specific risk analysis performed to establish the out of service time.

The following administrative controls will be applicable upon entry into plant conditions which rely on the extended CT.

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).

2. Weather conditions must be conducive to perform planned maintenance on the offsite circuits.

3. The offsite power supply and switchyard conditions must be conducive to perform maintenance on the offsite circuits.

4. Switchyard access must be monitored and controlled per procedures.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 33 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 36 days) allowed prior to complete restoration of the LCO. The 33 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 30 day and 33 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)