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December 31, 2003

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
LICENSE AMENDMENT REQUEST (LAR) 03-07
REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1 AND 3.8.9, EXTENSION OF ALLOWABLE COMPLETION TIMES FOR DIESEL GENERATORS, QUALIFIED OFFSITE CIRCUITS, AND AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEM

Gentlemen:

Pursuant to 10CFR50.90, TXU Generation Company LP (TXU Energy) hereby requests an amendment to the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating the attached change into the CPSES Unit 1 and 2 Technical Specifications. This change request applies to both units.

The proposed changes will revise Technical Specification (TS) 3.8.1 for AC Sources Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Diesel Generator (DG) and an inoperable offsite circuit (i.e., startup transformer). The proposed changes will also revise Technical Specification (TS) 3.8.9 for Distribution Systems - Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable AC electrical power distribution system (i.e., 6.9 kV AC safety bus).

This proposed change related to TS 3.8.1 (Action B.4) is based on the methodology provided in WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical

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Power System Completion Times," and associated Industry/Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-417, Revision 0.

TXU Energy's evaluation of the proposed changes includes traditional engineering analyses as well as a risk informed approach as set forth in the guidance of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications."

These proposed changes will provide operational flexibility by allowing more efficient application of plant resources to safety significant activities. These proposed changes will (1) allow performance of periodic DG overhauls on-line, improving DG availability during shutdown, (2) allow maintenance of the startup transformers at power, and (3) allow repairs of the 6.9 kV AC safety bus at power.

The justification for the change to the DG Completion Time is based upon a risk-informed, deterministic evaluation consisting of three main elements: (1) the availability of offsite power via separate and physically independent offsite circuit startup transformers, (2) assessment of risk that shows an acceptable small increase in risk (as indicated by Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)), (3) continued implementation of a Configuration Risk Management Program (CRMP) while the DG, startup transformer, or safety bus is in an extended Completion Time. These elements provide the basis for the requested TS change by providing a high degree of assurance of the capability to provide power to the safety related 6.9 kV AC Engineered Safety Features (ESF) buses during the extended Completion Times.

Attachment 1 provides a detailed description of the proposed changes, a safety analysis of the proposed changes, TXU Energy's determination that the proposed changes do not involve a significant hazard consideration, a regulatory analysis of the proposed changes and an environmental evaluation. Attachment 2 provides the affected Technical Specification pages marked-up to reflect the proposed changes. Attachment 3 provides proposed changes to the Technical Specification Bases for information only. These changes will be processed per CPSES site procedures. Attachment 4 provides retyped Technical Specification pages which incorporate the requested changes. Attachment 5 provides retyped Technical Specification Bases pages which incorporate the proposed changes.

TXU Energy requests approval of the proposed License Amendment by January 1, 2005, to be implemented within 60 days. The approval date was administratively selected to allow for NRC review but the plant does not require this amendment to allow continued safe full power operations.

In accordance with 10CFR50.91(b), TXU Generation Company LP is providing the State of Texas with a copy of this proposed amendment.

This communication contains no new or revised commitments.

Should you have any questions, please contact Mr. Carl B. Corbin at (254) 897-0121 or email at ccorbin1@txu.com.

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

Executed on December 31, 2003.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC
Its General Partner

Mike Blevins

Mike Blevins
Senior Vice President & Principal Nuclear Officer

CBC/cbc

Attachments
1. Description and Assessment
2. Markup of Technical Specifications pages
3. Markup of Technical Specifications Bases pages (for information)
4. Retyped Technical Specification Pages
5. Retyped Technical Specification Bases Pages (for information)
6. Comanche Peak Switchyards and Distribution Subsystem Figures

c - B. S. Mallet, Region IV
W. D. Johnson, Region IV
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Ms. Alice Rogers
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ATTACHMENT 1 to TXX-03137

DESCRIPTION AND ASSESSMENT

LICENSEE'S EVALUATION

1.0 DESCRIPTION

By this letter, TXU Generation Company LP (TXU Energy) requests a License amendment to the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating the attached changes into the CPSES Unit 1 and 2 Technical Specifications. The proposed changes will revise Technical Specification (TS) 3.8.1 for AC Sources Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Diesel Generator (DG) and an inoperable offsite circuit (i.e., startup transformer). The proposed changes will also revise Technical Specification (TS) 3.8.9 for Distribution Systems - Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable AC electrical power distribution system (i.e., 6.9 kV AC safety bus).

The license amendment request also incorporates changes for TS 3.8.1 and 3.8.9 which revise the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions of inoperability during any single continuous failure to meet the Limiting Condition for Operation.

The requested changes were based upon CPSES plant specific risk-informed and deterministic evaluations performed in a consistent manner with the risk-informed approaches endorsed by Regulatory Guides 1.174 (Reference 1) and 1.177 (Reference 2). The proposed changes would increase operational flexibility and provide additional allowances for performance of testing, repairs, and periodic maintenance while at power.

The CPSES Final Safety Analysis Report (Sections 1A(B) and 8) (Reference 3) will be updated as required to reflect this License Amendment Request. The FSAR will be updated after the License Amendment Request has been approved and implemented.

2.0 PROPOSED CHANGE

TXU Energy's requested changes to TS Sections 3.8.1 and 3.8.9 are summarized below. The changes to TS 3.8.1 and 3.8.9 are marked-up (Attachment 2) on the Technical Specification pages.

Technical Specification (TS) 3.8.1, AC Sources - Operating

TS 3.8.1, "AC Sources – Operating," Actions, Page 3.8-2, Action A.3, Completion Time: change "72 hours <u>AND</u> 6 days from discovery of failure to meet LCO <u>OR</u> 21 days for a one time preventive maintenance outage on Startup Transformer XST2 to be completed by February 28, 2002" to "30 days <u>AND</u> 40 days from discovery of failure to meet LCO"

TS 3.8.1, "AC Sources – Operating," Actions, Page 3.8-4, Action B.4, Completion Time: change "72 hours <u>AND</u> 6 days from discover of failure to meet LCO" to "10 days AND 40 days from discovery of failure to meet LCO"

(The word discover is changed to discovery. This change corrects an inadvertent editorial error introduced in the Technical Specifications during the review and approval of License Amendment 64)

Technical Specification (TS) 3.8.9, Distribution Systems - Operating

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action A.1, Completion Time: change "8 hours AND 16 hours from discovery of failure to meet LCO" to "72 hours AND 80 hours from discovery of failure to meet LCO"

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action B.1, Completion Time: change "AND 16 hours from discovery of failure to meet LCO" to "AND 80 hours from discovery of failure to meet LCO"

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action C.1, Completion Time: change "AND 16 hours from discovery of failure to meet LCO" to "AND 80 hours from discovery of failure to meet LCO"

In summary, (1) the specifications for AC Sources Operating have been revised to permit an offsite circuit inoperable TS Action Completion Time of up to 30 days, (2) the specifications for AC Sources Operating are revised to permit an Diesel Generator (DG) TS Action Completion Time of up to 10 days, (3) the specifications for Distribution Systems – Operating have been revised to permit a 6.9 kV AC safety bus TS Action Completion Time of up to 72 hours, and (4) revises second completion time for certain required actions to establish a limit on the maximum time allowed for any combination of Conditions of inoperability during any single continuous failure to meet the LCO.

For information only, this LAR includes proposed associated changes to the TS Bases 3.8.1, "AC Sources – Operating," and TS Bases 3.8.9, "Distribution Systems – Operating."

The changes to TS Bases 3.8.1 and 3.8.9 are marked-up (Attachment 3) on the TS Bases pages.

Technical Specification (TS) Bases 3.8.1, "AC Sources – Operating"

Revises Bases information to reflect the updated Completion Times.

Technical Specification (TS) Bases 3.8.9, "Distribution Systems – Operating"

Revises Bases information to reflect the updated Completion Times.

Retyped Technical Specification pages and Technical Specification Bases pages which incorporate the proposed changes are provided in Attachments 4 and 5, respectively.

3.0 BACKGROUND

3.1 Extension of AC Electrical Power System Completion Times

The Completion Time extensions for the Diesel Generators (DGs) and the offsite circuit Startup Transformers (STs) are expected to be used for performing maintenance activities. The extension for the 6.9 kV AC safety buses is expected to be used in the event maintenance is required. Section 4.1 includes a detailed description of the on-site and off-site power system for Comanche Peak Steam Electric Station (CPSES). The proposed change to the DG is consistent with the methodology provided in Westinghouse Owners Group (WOG) Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion times" (Reference 4). The proposed change is also consistent with associated Industry Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-417, Rev. 0 (Reference 5). For consistency with the other plants participating in WCAP-15622, CPSES provided information which supported a 7 day completion time for the Diesel Generator. However, as stated in WCAP-15622, CPSES is requesting a completion time greater than 7 days for the EGD as supported by this submittal.

Extension of Offsite Cicuit (Startup Transformer XST1 or XST2)

In order to perform maintenance on a Startup Transformer (ST - XST1 or XST2) both CPSES units would need to be in the cold shutdown state simultaneously for an extended period of time. This is due to the fact that each Startup Transformer provides one of the two TS required offsite power sources to both Unit 1 and Unit 2. Both units are required to maintain two offsite power sources when above cold shutdown conditions. Based on experience with these and similar transformers, the proposed preventive maintenance could not be completed in the relatively short duration currently allowed by TS. CPSES Technical Specifications allow 72 hours to restore the transformer to an operable status. A plant shutdown to cold shutdown is required if the transformer is not restored to an operable status within the Completion Time limits. As will be discussed in the next section of this submittal, little preventive maintenance could be performed in such a short period of time.

Given the importance of offsite power sources, it is prudent to maintain them in a reliable condition while minimizing their unavailability.

Due to power generation demands and overall economic considerations, it is not anticipated for planned outage schedules to include overlapping, or simultaneous shutdown of both units of sufficient duration to perform the recommended Startup Transformer preventive maintenance.

CPSES intends to use the proposed 30 day Completion Time (CT) to perform planned outages of a Startup Transformer. Thirty days has been requested to ensure the CT can be met even with emergent issues and that a cold shutdown would be unlikely. The proposed CT of 30 days is adequate to perform the proposed preventive maintenance requiring disassembly of the transformer and to perform post-maintenance and operability tests required to return the offsite circuit to operable status.

Extension of Completion Time for an Inoperable Diesel Generator

The current Completion Times associated with inoperable AC power source(s) are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974, (Reference 6) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., Completion Times) that the NRC considers acceptable if the number of available AC power sources are less than the LCO. This change deviates from R. G. 1.93 as described in Section 5.2.1.

Extension of AC electrical power distribution subsystem (6.9 kV AC safety bus)

The Completion Time for the 6.9 kV AC safety buses may be extended to 72 hours. Details of the analysis are contained in Section 4.0 of this report. This will permit repair of 6.9 kV AC safety bus at power and improve 6.9 kV AC safety bus availability during shutdown Modes. Plant configuration changes for planned and unplanned maintenance of the 6.9 kV AC safety bus as well as the maintenance of equipment having risk significance is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the consequences of a severe accident.

3.2 Elimination of Second Completion Times

This amendment application also incorporates some of the changes included in TSTF-439, Revision 1, which eliminates the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions of inoperability during any single continuous failure to meet the Limiting Condition for Operation.

A second Completion Time was included in the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of conditions of inoperability during any single continuous failure to meet the LCO. The intent of the second Completion Time was to preclude entry into and out of the ACTIONS for an indefinite period of time by providing a limit on the amount of time that the LCO could not be met for various combinations of Conditions. The second Completion Time was derived by adding the individual Completion Times associated with the affected Required Actions.

Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" justified extending the Completion Times associated with certain Required Actions using a risk-informed approach and was submitted to the NRC for review in June 2001. The Completion Times associated with two of these Required Actions also contained a second Completion Time. In order to implement the extended Completion Times justified in the Topical Report, the two Completion Times (one being the current Completion Time not being changed, and one being the Completion Time proposed to be changed) associated with the applicable Required Actions were added to obtain a new and increased second Completion Time.

The NRC transmitted a letter to NEI in November 2001 discussing a staff concern identified during their review of Topical Reports WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (TSTF-417) (References 4 and 5) and CE NSPD-1045, "Joint Applications Report, Modification to the Containment Spray System, and the Low Pressure Safety Injection System Technical Specifications" (TSTF-409) (Reference 9). Specifically, the NRC indicated that increases in the Improved Standard Technical Specification Completion Time limits by adding together risk-informed and deterministic values using engineering judgment would not be approved. As noted in Section 3.2 of Attachment 1 to Reference 17, in subsequent discussions with the NRC in September 2003, the NRC indicated it was acceptable to increase the second Completion Time by adding together risk-informed and deterministic values. This is further discussed in Section 4.4.

4.0 TECHNICAL ANALYSIS

The proposed changes have been evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increases in core damage frequency (CDF) and large early release frequency (LERF) are small and consistent with the NRC Safety Goal Policy Statement (Reference 19), and the acceptance criteria in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998, (Reference 1) and Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," August 1999 (Reference 2) are met.

The justification for the use of an DG extended Completion Time is based upon a risk-informed and deterministic evaluation consisting of three main elements: 1) the availability of the "preferred" and "alternate" offsite power sources via the startup transformers (STs), (2) assessment of risk that shows an acceptable small increase in risk (as indicated by Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)), (3) continued implementation of a Configuration Risk Management Program (CRMP) while the DG is in an extended Completion Time. The CRMP is used for DG as well as other work and helps ensure that there is no significant increase in the risk of a severe accident while any DG maintenance is performed. These elements provide the bases for the proposed TS change by providing a high degree of assurance that power can be provided to the ESF buses during all Design Basis Accidents (DBAs) during the DG extended Completion Time.

The unavailability of one startup transformer or one safety related (Class 1E) 6.9 kV AC bus are already considered in the plant design. The increased outage time for a startup transformer has no affect on the capability of each transformer to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously. The increased Completion Time for a safety related bus has no affect on the capability of each safety related bus to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1 Traditional Engineering Considerations

4.1.1 Diesel Generator Completion Time Extension

4.1.1.1 Defense-in-depth

The impact of the proposed TS changes were evaluated and determined to be consistent with the defense-in-depth philosophy. The defense-in-depth philosophy in reactor design and operation results in multiple means to accomplish safety functions and prevent release of radioactive material.

CPSES is designed and operated consistent with the defense-in-depth philosophy. The units have diverse power sources available (e.g., DGs and STs) to cope with a loss of the preferred AC source (i.e., offsite power). The overall availability of the AC power sources to the ESF buses will not be reduced significantly as a result of increased on-line maintenance activities. It is therefore, acceptable, under certain controlled conditions, to extend the Completion Time and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

While the proposed change does increase the length of time an DG can be out of service during unit operation, it will increase the availability of the DGs while the unit is shutdown, which will provide an overall risk reduction throughout the operating cycle. The increased availability of the DG while shutdown will increase the systems defense-in-depth during outages. Even with one DG out of service there are multiple means to accomplish safety functions and prevent release of radioactive material. The CPSES PRA evaluation confirms the results of the deterministic analysis, i.e., the adequacy of defense-in-depth and that protection of the public health and safety are ensured.

System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. Implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. Station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to ensure adequate defense-in-depth whenever the DGs are out of service. In addition, appropriate personnel are trained on the operation and maintenance of the DGs.

No new potential common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised.

Independence of physical barriers to radionuclide release is not affected by these proposed changes.

Adequate defenses against human errors are maintained. These proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. Qualified personnel will continue to perform DG maintenance and overhauls whether they are performed on-line or during shutdown. No other new actions are necessary because the overhaul will be performed on-line.

"Conformance with NRC General Design Criteria," Section 3.1 of the Final Safety Analysis Report (FSAR) (Reference 1) provides the basis for concluding that the stations fully satisfy and are in compliance with the NRC General Design Criteria (GDC) in Appendix A to 10 CFR Part 50. These proposed changes do not affect the basis for this conclusion and do not affect compliance with NRC GDC.

4.1.1.1.1 Availability of the Off-Site Power System

The transmission lines of TXU Energy affiliate Oncor comprise an integrated system with operations coordinated by the system dispatcher so as to maintain system reliability. Transmission systems consist of 345-kV lines for bulk supply and 138-kV and 69-kV lines to transmit power to load-serving substations. Composition of TXU Energy's generation sources include fossil fuel plants (lignite, gas/oil, and combustion turbines) and the CPSES nuclear plant (interconnected). Direct ties to other utilities in Texas are maintained by the Electric Reliability Council of Texas (ERCOT), creating a highly reliable integrated system.

The CPSES output is connected to the 345-kV transmission system via the CPSES Switchyard. The startup and shutdown power for the units are derived from the 138-kV and 345-kV system. Separate connections to the 138-kV Switchyard and the 345-kV Switchyard provide independent and reliable offsite power sources to the Class 1E systems. The highly reliable network interconnections are made through five 345-kV and two 138-kV transmission lines to the Oncor grid as shown on the figures in Attachment 6.

Two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either unit. The preferred source to Unit 1 is the 345-kV offsite supply from the 345-kV Switchyard and the startup transformer, XST2; the preferred source to Unit 2 is the 138-kV offsite supply from the 138-kV Switchyard and the startup transformer, XST1. Each of the startup transformers (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses. This eliminates the need for automatic transfer of safety-related loads in the event of a unit trip. In the event one startup transformer (e.g., XST1, a preferred source) becomes unavailable to its normally fed class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme.

The preferred power sources supply power to the Class 1E buses during plant startup, normal operation, emergency shutdown, and upon a unit trip.

Each startup transformer has the capacity to carry the required Class 1E loads of both units during all modes of plant operation.

The Class 1E buses of each unit can be supplied by two independent and reliable immediate-access offsite power sources. Sharing of these offsite power sources between the two units has no effect on the station electrical system reliability because each transformer is capable of supplying the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.1.1.2 Availability of the On-Site Power System

The standby AC Power System is an independent, onsite, automatically starting system designed to furnish reliable and adequate power for Class 1E loads to ensure safe plant shutdown and standby power when preferred and alternate power sources are not available. Four independent diesel generator sets, two per unit, are provided.

Loads important to plant safety are divided into redundant divisions. Each division is supplied standby power from a dedicated DG. Each DG is connected to its dedicated bus directly without utilizing any auxiliary transformer. The DGs are physically and electrically independent. With this arrangement, redundant components of all ESF systems are supplied from a separate ESF bus so that no single failure can jeopardize the proper functioning of redundant ESF loads. Due to the redundancy of the units' ESF divisions and DGs, the loss of any one of the DGs will not prevent the safe shutdown of the unit. The total standby power system, including DGs and electrical power distribution equipment, satisfies the single failure criterion.

The purpose of the DGs is to provide an onsite standby power source upon the loss of preferred and alternate offsite power sources. An DG is automatically started by a safety injection signal or an under-voltage signal on the 6.9 kV ESF bus served by the DG. Upon loss of voltage on a 6.9 kV ESF bus due to a Loss of Offsite Power (LOOP) with no safety injection signal present, under-voltage relays automatically start the DGs. Sequential loading of the DG is automatically performed.

The DG feeder breaker will close to its associated load group automatically only if the other source feeder breakers to the load group are open. When the DG feeder breaker is closed, no other source feeder breaker will close automatically. Design and procedural controls ensure that no means exist for connecting redundant load groups with each other.

The design basis for the DGs is that loss of one DG will not result in the loss of safety function. With two DGs available per unit, the system is capable of performing its intended safety function with an assumed single failure of one DG.

4.1.1.1.3 Station Blackout (SBO) DG Capacity

CPSES is able to withstand and recover from a SBO event of 4 hours in accordance with the guidelines of RG 1.155, "Station Blackout," dated August 1988 (Reference 10).

The assumptions used in the SBO analysis regarding the availability and reliability of the DGs are unaffected by this proposed change. The results of the SBO analysis are also unaffected by this change.

The impact of a SBO event on plant risk is discussed in Section 4.2, "Evaluation of Risk Impact."

FSAR References

Related background in the CPSES FSAR is found primarily in Section 1A(B) and Section 8. Compliance with NRC design criteria is described in detail in FSAR Section 8.1, "INTRODUCTION," (Reference 3) and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES" (Reference 3). On site power systems are described in FSAR section 8.3 and Station Blackout is described in Appendix 8B of the FSAR.

4.1.1.1.4 Onsite Power System Design Criteria

Compliance with NRC design criteria is described in detail in FSAR Section 8.1, "INTRODUCTION," (Reference 1) and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES" (Reference 1). Safety-related systems and components that require electrical power to perform their safety-related function are defined as Class 1E loads. These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems," (Reference 11) as discussed in Appendix 1A(B) of the FSAR (Reference 3) is not affected by this change. These proposed changes do not add any loads to the DGs; therefore, the selection of the capacity of the DGs for standby power systems and conformance to the applicable Sections of Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies," (Reference 12) are not affected by this change.

CPSES conformance with Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," (Reference 13) is described in detail in Appendix 1A(B) to the FSAR (Reference 3).

CPSES conformance with Regulatory Guide 1.93, Revision 0, dated December 1974, titled "Availability of Electric Power Sources," (Reference 6) is described in Appendix 1A(B) to the FSAR (Reference 3).

Aside from the exception discussed above, the station currently conforms to Regulatory Guide 1.93 and specifically the position that the 72-hour Completion Time will not be entered for preventative maintenance of the DGs. If the proposed changes are approved, the stations will continue to conform to RG 1.93 with the exception that the allowed Completion Time for restoration of an DG will be increased to 10 days and the Completion Time may be used for DG preventative maintenance.

Review of other key design criteria applicable to onsite electrical systems revealed that their respective commitments would be unaffected by these proposed changes. These commitments include: Regulatory Guide 1.53, dated June 1973, titled, "Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems," (Reference 14); Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions," (Reference 15); and Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 16).

4.1.1.2 Other Considerations

As discussed in Section 5.2, conformance with relevant regulatory guidance is not affected by these proposed changes, with the exception of Regulatory Guide (RG) 1.93. The RGs cited in the previous section endorse industry standards.

Diesel Generator operability following repair/maintenance activities will continue to be based on surveillance tests recommended by Regulatory Guides 1.9, 1.108, and 1.137. A complete 100% tear down of the Diesel Generator at power, even with a 10 day Completion Time is not likely to be planned. The surveillance test to be performed to ensure Diesel Generator operability is dependent on the scope of the maintenance activities performed. For normal maintenance (which is the majority of the outage scope), the fast start and load run would be the only testing required. However, to set the governor or voltage regulator system in the event of a changeout, the full load reject at power would be required.

Safety analysis acceptance criteria in the FSAR continue to be met. The proposed changes do not affect any assumptions or inputs to the safety analyses.

Unavailability of a single DG due to maintenance does not reduce the number of DGs below the minimum required to mitigate all DBAs. In addition, the proposed changes have no impact on the availability of the two off-site sources of power. The effect on FSAR acceptance criteria has been assessed assuming that one DG is out of service and no additional failures on the maintenance unit occur. All safety functions continue to be available and acceptance criteria are met.

4.1.2 Offsite circuit (offsite circuit Startup Transformer) Completion Time Extension

As stated above in Section 4.1.1, two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either unit. The preferred source to Unit 1 is the 345-kV offsite supply from the 345-kV Switchyard and the startup transformer, XST2; the preferred source to Unit 2 is the 138-kV offsite supply from the 138-kV Switchyard and the startup transformer, XST1. Each startup transformer (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses. In the event one startup transformer (e.g., XST1, a preferred source) becomes unavailable to supply its normally fed class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme.

The unavailability of one startup transformer is already considered in the design. The increased outage time for a startup transformer has no affect on the capability of each transformer to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.3 AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) Completion Time Extension

Two independent and redundant 6.9 kV AC Class 1E buses are provided for each unit, each capable of supplying the required safety-related loads to safely shut down the unit following a DBA. Each Class 1E bus can be fed from two independent offsite power sources or the diesel generator assigned to the bus. Redundant safety-related loads are divided between Trains A and B so that loss of either train does not impair fulfillment of the minimum shutdown safety requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains.

Safety-related (Class 1E) 6.9 kV AC buses 1EA1 and 1EA2 for Unit 1 and 2EA1 and 2EA2 for Unit 2 are fed directly from dedicated startup transformers XST1 and XST2. There are no interconnections between safety-related and non-safety-related 6.9 kV AC buses.

All Class 1E buses are arranged in such a way that train A buses are electrically and physically isolated from train B buses to satisfy the single failure criteria.

The unavailability of one safety-related (Class 1E) 6.9 kV AC bus is already considered in the design. The increased outage time for a safety-related bus has no affect on the capability of each safety-related bus to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.4 Application of Configuration Risk Management Program (CRMP)

Methodologies (CRMP and Safety Monitor™) associated with risk monitoring and contingency action planning currently exist at CPSES and provide acceptable assurance of continued safe reactor operations during periods of equipment inoperability. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage.

Additionally plant procedures currently require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Thus if the planned maintenance on any of these components is greater than 50% of the requested Completion Time, plant procedures ensure specific management attention and overall heightened plant awareness in support of the planned activity.

In accordance with the CRMP, equipment identified as important in mitigating an accident will be administratively controlled and protected to ensure that the equipment, including components such as; the Diesel Generators, the Turbine Driven Auxiliary Feedwater Systems, Station Service Water Systems, and Blackout Sequencers, assuming both units at power, remain operable and available for the duration of the planned maintenance outage. The CRMP also requires identification and preparation of contingency plans as warranted.

Work Planning

For preventive maintenance, extensive planning is performed. Two important aspects of this planning are the pre-staging of needed equipment and confirmation that qualified personnel are available to perform the maintenance.

No major switchyard Activity will be allowed

During these maintenance activities, activity in the switchyards will be closely monitored and controlled. No activity will be allowed that could challenge the operability of the other offsite AC power source as controlled by plant procedures.

Controls or Prohibition of Maintenance or Testing of Other Important Equipment

To minimize risk during a planned maintenance outage for any one of these components, maintenance and testing of any of the other DGs, station transformers (XST1 or XST2) or the 6.9 kV AC safety bus would not be conducted.

Whether planned or unplanned, activities that result in the inoperability of a TS required offsite power source require establishing contingency actions to protect all other available sources of power. For example, if XST2 were to be removed from service for preplanned preventative maintenance, elective maintenance would not be allowed on XST1 or any of the DGs that are supporting an operable bus on either unit.

Scheduling to Minimize Grid Load and Weather Impacts

Scheduling to Minimize Grid Loading and Weather Related Impacts - The prospective schedule window for the proposed outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus, times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window. For the case of the Startup Transformer, the schedule also anticipates suitable weather conditions conducive to the performance of the mostly outdoor transformer maintenance tasks. These considerations include equipment protection, minimized job interruptions, and good worker conditions.

Scheduling to Maximize Operator, Maintenance and Management Focus

By performing this maintenance on line when no other significant activities are taking place (as opposed to an outage, for example, where many competing tasks are occurring at the same time), the plant operators, the maintenance staff and plant management will be able to focus on these activities. The equipment outage would be scheduled to ensure the availability of experienced manpower and technical support personnel, as well as to reduce the potential for distraction due to competing job demands.

Unit Work Schedules Modified to Support Maintenance

Work Scheduling has routine testing and preventive maintenance activities that are normally performed on a 12 week rotating basis. Work schedules can be adjusted to ensure that surveillance testing of equipment identified as important to Loss of Offsite Power and Station Blackout considerations is demonstrated current prior to the start of the equipment outage work window. Additional routine testing and preventive maintenance should not be required on the equipment for the duration of the planned outage.

Turbine Drive Auxiliary Feedwater Pumps Protected

The steam driven emergency feedwater pumps (one per unit and called the Turbine Driven Auxiliary Feedwater pumps at CPSES) are protected from elective maintenance activities since they are considered a mitigation to station blackout conditions when electric feedwater pumps would be unavailable. Surveillance testing of any such "protected" equipment that falls due during the period that these components (i.e., DG, startup transformer) are out of service would be performed prior to removing them from service. Limiting testing in this way protects availability of equipment during the maintenance window. This does not imply that surveillance testing requirements will not be performed on "key equipment" but only that TS Surveillance Testing will be shifted as allowed by Technical Specifications (e.g., within 1.25 times the interval specified in the Frequency). Risk strategies and maintenance practices at CPSES also act to ensure replacement parts are available and pre-staged, along with other support equipment that may be required prior to entry into the maintenance window. Other factors that are considered at CPSES when offsite power sources are involved include the time of year (projected atmospheric stability), projected offsite power grid requirements, overall plant condition, availability of qualified and experienced personnel, etc.

Summary

In summary, CPSES has a rugged design which retains desired design features such as defense in depth, the ability to mitigate design basis accidents with these components being out of service. The following is a listing of contingencies or conditions that will be applicable during the preventative or corrective maintenance (as applicable) windows to deterministically enhance the capability of the plant:

1. The Configuration Risk Management Program of TS 5.5.18 will be applied during the extended outage.
2. Controls will be in place to limit maintenance on other important equipment
3. All necessary equipment will be prestaged (preventative maintenance)
4. Necessary personnel will be pre-assigned and verified available (preventative maintenance)
5. The maintenance will be scheduled to minimize potential adverse impact from the electrical grid or weather (preventative maintenance)
6. Major switchyard activities will be prevented
7. Surveillance testing of key equipment will be performed prior to removing the components from service. This does not imply that surveillance testing requirements will not be performed on "key equipment" but only that TS Surveillance Testing will be shifted as allowed by Technical Specifications (e.g., within 1.25 times the interval specified in the Frequency). (preventative maintenance)
8. The focus of operators, maintenance personnel and management is enhanced by scheduling the work when competing activities are not occurring. (preventative maintenance)
9. The operability of the Turbine Driven Auxiliary Feedwater Pump will be controlled.

For these increases in allowed Completion Time for preventive maintenance, the plant remains in a condition for which the plant has already been analyzed and the deterministic enhancements noted above will be implemented: therefore, from a deterministic aspect, these changes are acceptable.

4.1.5 Discussion of Technical Specification Bases and Conclusions of Deterministic Evaluation

For the increased Completion Times proposed for the DGs, startup transformers and the AC distribution buses, the plant remains in a condition for which the plant has already been analyzed: therefore, from a deterministic aspect, these changes are acceptable. To ensure the risk informed completion times are implemented consisistent with the CRMP, discussions similar to those provided below will be incorporated into the Technical Specification bases.

Diesel Generator Completion (Technical Specfication 3.8.1)

In Condition B of TS 3.8.1, 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.

This requested Completion Time (CT) is intended to be used in the same manner as the current CT, that is for repair and preventive maintenance activities. With regard to repair, historically, at CPSES the average duration of repair activities is significantly less than the current CT of 72 hours, though there may be more than one such entry per year. The frequency and duration of these repair activities are not expected to increase as a result of extending the CT. The foregoing does not imply that, if necessary, CPSES will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. This 10 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 4. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the DG to ensure that the DG is capable of fulfilling its intended functions. If the performance or condition of the DG does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 B.4 would result in unacceptable unavailability of the DGs, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 10 day Completion Time.

Administrative controls applied during any extended DG outage time for voluntary planned maintenance activities ensure or require that:

a. Switchyard Activity - During this maintenance on the DG, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures currently require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

In accordance with the CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Startup Transformers, 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, the opposite train Diesel Generator, Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the planned Diesel Generator (DGs) maintenance outage.

c. Scheduling to Minimize Grid Loading and Weather Related Impacts - The prospective schedule window for the proposed DG outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus, times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window.

Offsite Circuit Startup Transformer (Technical Specification 3.8.1)

In Condition A of TS 3.8.1, the remaining offsite circuit is 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.

This requested Completion Time (CT) is intended to be used in the same manner as the current CT, that is for repair and preventive maintenance activities. With regard to repair, historically, at CPSES the average duration of repair activities is significantly less than the current CT of 72 hours, though there may be more than one such entry per year. The frequency and duration of these repair activities are not expected to increase as a result of extending the CT. The foregoing does not imply that, if necessary, CPSES will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. A completion time approaching 30 days also allows for declaring or rendering a startup transformer inoperable for the performance of voluntary, planned maintenance activities. This 30 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 16. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the offsite circuits to ensure that the offsite circuit is capable of fulfilling its intended functions. If the performance or condition of the offsite circuit does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 A.3 would result in unacceptable unavailability of the offsite circuit, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 30 day Completion Time.

Administrative controls applied during any extended offsite circuit (Startup Transformer) outage time for voluntary planned maintenance activities ensure or require that:

a. Switchyard Activity - During this maintenance on the Startup Transformer, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

   In accordance with the CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Emergeny Diesel Generators (DGs), the remaining operable Startup Transformer, 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the Startup Transformer maintenance outage.

c. Scheduling to Minimize Grid Loading and Weather Related Impacts - The prospective schedule window for the proposed Startup Transformer outage will be implemented during the time of the year when the weather at CPSES historically, has not been severe and threatening to off-site power. Thus, times of peak tornado, and thunderstorm frequency or likelihood of winter ice storms will be considered in identifying the schedule window. The schedule also anticipates suitable weather conditions conductive to the performance of the mostly outdoor transformer maintenance tasks. These considerations include protection, minimized job interruptions and good worker conditions.

<u>AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus)</u>

This 72 hour Completion Time is a risk-informed Completion Time (CT) based on a plant-specific analysis using the methodology in this license amendment request. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) to ensure that the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) is capable of fulfilling its intended functions. If the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.9 A.1 would result in unacceptable unavailability of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus), which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP)

Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement.

4.2 Evaluation of Risk Impact

The purpose of this section is to document the Probabilistic Safety Assessment (PRA) conducted in support of the CPSES submittal of an allowed Completion Time extension request for 6.9 kV AC components. These components consist of the Diesel Generators (1DG1, 1DG2, 2DG1, 2DG2), offsite circuit startup transformers (XST1, XST2) and 6.9 kV AC safety buses (1EA1, 1EA2, 2EA1, 2EA2). Risk-informed changes to a nuclear power plant's licensing basis consist of both deterministic and probabilistic evaluations, as required by NRC Regulatory Guides 1.174 (Reference 1) and 1.177 (Reference 2). This Section documents the probabilistic evaluation and is intended to supplement the deterministic engineering evaluations described in Section 4.1.

The risks associated with extending the Completion Time for these components during power operations (MODE 1) and the risks associated with these components being unavailable during shutdown were determined and compared. The Completion Time extensions for the Diesel Generators and the startup transformers are expected to be used to support maintenance activities. The extension for the 6.9 kV AC safety buses are expected to be used in the event repair activities are required. A more detailed discussion on the use of the extended completion times is provided in Section 4.1.5.

The probabilistic evaluations presented in the following sections support the allowed Completion Time extension request for 6.9 kV AC components (Diesel Generators, offsite circuit startup transformers, and 6.9 kV AC safety buses). The results of the evaluations presented herein justify extending the allowed Completion Times for these components. The risk methods employed are detailed in Section 4.2.1, followed by a discussion on PRA quality in Section 4.3. The analysis tasks and results are presented in Sections 4.2.1 and 4.2.2, respectively.

4.2.1 Overall Methodology

This section describes the CPSES PRA model for internal events and provides a description of the overall methodology that was used for the PRA analysis in support of this submittal. The features of the CPSES PRA model that were used in the analysis are also described. In general, the overall methodology is designed to address the considerations described in the Regulatory Guides 1.174 and 1.177.

<u>Description of the CPSES PRA Model</u>

The CPSES PRA model for internal events is an all-modes model that allows quantification of configurations to determine core damage frequency (CDF) and large early release frequency

(LERF) at power (MODE 1) and in transition (MODES 2 through 4). Quantification of the model in shutdown (MODES 5 and 6) address CDF only. The CPSES PRA model for internal events also includes spent fuel pool modeling for core-off load configurations. A description of the CPSES PRA model pedigree is provided in the sections that follow.

Data Review and Model Evaluation

In general, PRA and deterministic data related to the affected components were reviewed. For the probabilistic portion, this consisted of PRA elements that directly model the component and also related supporting documents that implicitly impact how the PRA was constructed or developed. Consideration was given to each of the PRA tasks in order to define what documents needed to be reviewed in more detail.

Information collected and reviewed in support of the 6.9 kV AC component Completion Time evaluation are listed below.

- CPSES Full Power & Shutdown PRA analysis files and computer model.
- Reactor Coolant Pump Seal LOCA model.
- DG common cause failure modeling data and techniques.
- Loss of Offsite Power Initiating Event Frequency and post-initiator plant response.
- Station Blackout Initiating Event Frequency and post-initiator plant response.
- Emergency Operating Procedures.
- Maintenance Rule data for the DG.
- Maintenance Rule data for the affected components (with historical outage times).
- Detailed refueling outage schedules.

The scope of the existing PRA was reviewed to ensure that it is adequate to evaluate this application. For the 6.9 kV AC components, there are two key areas: (1) review aspects of the PRA model related to 6.9 kV AC electrical power to ensure high quality standards for the submittal; and (2) review the RCP seal LOCA model to ensure integrity and completeness. The 6.9 kV AC system fault tree models and DG reliability data were reviewed. This review included common cause failure parameters, unavailability parameters, failure rates, and level of detail of these system models. Similarly, the CPSES Loss of Offsite Power (LOOP) and Station Blackout (SBO) models were reviewed.

The review of the PRA model to ensure high quality standards is required for all risk-informed submittals under Regulatory Guide 1.174. The review of the RCP Seal LOCA model is required when the utility has not incorporated the Brookhaven RCP Seal LOCA model. For this submittal, TXU Energy reviewed the DG reliability data, the Loss of Offsite Power and Station Blackout sequences, and the RCP seal LOCA model using the Westinghouse Owners Group certification guidelines (Reference 21). The key areas reviewed are summarized below.

The 6.9 kV AC system fault tree models and DG reliability data were reviewed against the WOG review criteria. Minor modifications to the models and enhancements to the documentation needed to meet the PRA quality review criteria are described later in this section.

The CPSES Loss of Offsite Power (LOOP) and Station Blackout (SBO) models were also reviewed. Specifically, the LOOP frequency, LOOP recovery models, and the LOOP/SBO event trees were reviewed against the WOG review criteria. It was concluded that the LOOP and SBO modeling are detailed and appropriate. Additionally, the impact of a higher LOOP initiating event frequency was evaluated and it was concluded that although the risk of both full power and shutdown CDF will increase linearly (with an increase in initiating event frequency), the delta between power and shutdown CDF will remain constant. Therefore, the increased LOOP initiating event frequency does not change the conclusion of the evaluation and the proposed Completion Time extension.

It was confirmed that the existing RCP seal LOCA model contains all of the failure modes identified in the USNRC-approved Brookhaven RCP Seal LOCA model. The impact of using the Brookhaven RCP Seal LOCA model was then examined as a sensitivity analysis. This sensitivity analysis showed that if the Brookhaven RCP Seal LOCA model is used there is an increase in the baseline and configuration specific CDF when the DG is taken out of service. This results in a small increase in the risk metrics; however, that risk increase remains less than the change in risk if the major DG maintenance activities were completed during shutdown. That is, the shifting of DG maintenance from shutdown to full power still results in a risk advantage. Thus, the conclusions of this study remain unchanged and the proposed Completion Time extensions are supported.

The PRA model has been updated since the IPE and a number of areas have been strengthened. The HRA values were reviewed and recalculated when applicable. The common cause values were recalculated using the common cause tool developed by DS&S. Plant specific data has been used to Bayesian update the generic values used in the PRA model.

PRA Model Modifications

The following modifications to the CPSES PRA model were identified during the supporting document review process. The modified CPSES PRA model and its associated databases were imported into the Safety Monitor™ computer program to allow for easier quantification of various configurations required to support this submittal. Baseline comparisons of the Safety Monitor™ model baseline results and the CPSES PRA model (evaluated using the EPRI- CAFTA™ code) baseline results were completed and indicated good correlation between the two quantification methods.

During the evaluation process, the quantification runs that were performed to calculate CDF and LERF values were based on average test and maintenance values. In addition, to support the analysis, the data associated with certain basic events in the shutdown model were revised to allow the model to evaluate only the risk associated with damage to the fuel in the reactor vessel and to not consider the fuel in the fuel pool. The design of the spent fuel pool cooling system is such that it can be powered from either unit.

The CPSES PRA internal events model does not include contributions from internal fires, internal floods, seismic events and other external events. However, due to the common cause nature of these events and the fact that increased allowed Completion Times only impact the risk contributions of independent component unavailabilities, inclusion of floods, fires and external events would not impact the conclusions of this evaluation. While such contributions, if added would make small contributions to the base CDF, the change in CDF or LERF due to the increased allowed Completion Times would be unaffected.

Analysis Assumptions

The following assumptions were used in performing the analysis:

The Incremental Conditional Core Damage probability (ICCDP) and Large Early Release Probability (ICLERP) are calculated by assuming the affected component is in maintenance with any compensatory actions (e.g. no switchyard work resulting in a reduced LOOP frequency) for the entire CT duration. Component outage in the opposite train is not allowed (this would generally lead to Technical Specification 3.0.3 condition). However, component outages in the affected train are allowed and thus two cases are considered.

The delta CDF and LERF are calculated by assuming the affected component is in maintenance with any compensatory actions (e.g. no switchyard work resulting in a reduced LOOP frequency) for the CT duration and then adding the baseline CDF/LERF for the remainder of the duration. The basis for this is that the risk reduction measure (compensatory measures) would not be in affect during the remainder of the year. This approach is similar to the approach used in the Significance Determination Process (SDP) inspection manual.

The evaluation is based on the assumption that the extended allowed Completion Time would be applied to only one major maintenance activity per DG per refueling cycle. The cycle time is based on the current 18-month fuel cycle and an assumed total planned and unplanned outage duration of 30 days, which yields T_{CYCLE} = 518 days.

The Completion Time extensions for the startup transformers are expected to be used only for major maintenance activities. Therefore, the extended Completion Time should be used no more than once per year. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below. The Completion Time extension for the 6.9 kV AC buses is expected to be used only for maintenance activities and again is not anticipated to be used more frequently than once per year.

The CPSES model of record was considered as the base case. It was confirmed that the existing RCP seal LOCA model contains all of the failure modes identified in the USNRC-approved

Brookhaven RCP Seal LOCA model. Sensitivity studies examine the impact of implementing the Brookhaven RCP seal LOCA model.

The impact of the proposed Completion Time changes was evaluated using the CPSES PRA internal events model. Basic events in the shutdown model were revised to allow the model to evaluate only the risk associated with damage to the fuel in the reactor vessel and to not consider the fuel in the fuel pool. The design of the spent fuel pool cooling system is such that it can be powered from either unit.

The planned outage schedule from the 7th Unit 1 refueling outage is representative of future outages and thus provides the baseline for expected mode transition durations.

It was confirmed that the design basis of the plant is based on two safety-related diesel generators. Even though CPSES has in the past made the conservative decision to bring in a non-safety related temporary diesel generator during a refueling outage, for the purpose of this analysis it was not credited since the analysis compares the design bases at power versus shutdown. Some of the refueling outages conducted to date have been conducted using only the two safety-related diesels, though these were very early outages.

The assumption is made that CPSES will not plan maintenance that would lead to the diesel, startup transformer, or vital bus being unavailable when work is being performed in the switchyard. Also CPSES would not plan maintenance during the time of the year when the weather at CPSES has historically been severe (i.e. tornados, thunderstorms, or ice storms) or during summer peak loading of the grid. Therefore to account for this compensatory action the LOOP frequency was recalculated. The instantaneous CDF and LERF were calculated using the new LOOP frequency. The resulting CDF and LERF were combined with the baseline CDF, which used the normal LOOP frequency. This accounts for the CDF and LERF being reduced when the equipment is taken out of service. This allows credit for compensatory actions during the CT but does not take credit for the compensatory action for the whole year. If credit were taken for compensatory actions for the whole year the risk results would be non-conservative.

The Westinghouse methodology used in WCAP–15622-P was not used in this analysis for calculating the delta CDF and ICCDP metrics for the case of a DG in repair. This methodology artificially increases the metrics by overstating the common mode failure rate for the second DG and over-estimating the allowable time in a configuration where a common mode failure is possible and indeterminate. The methodology in WCAP-15622-P for calculating ICCDP for the repair event assumes that one DG is failed and the other DG has a failure rate increased by Beta for the duration of the exposed period. The baseline CPSES PRA model, consistent with the usual modeling approach, assumes the failure rate of the second DG remains at Beta times Lambda for all DG activities. The Technical Specifications require that the possibility of common mode failure be ruled out relatively soon after the event by either verifying no common cause or demonstrating operability of the other DG within 24 hours. If a common mode failure exists, the plant is shutdown by TS action statement 3.0.3. Thus, operating with this condition is precluded for extended periods and as far as the CT extension is concerned it has no bearing on risk compared to the current CT.

This conclusion can be drawn because the CCF exposure time is dependent only on the DG common mode failure Technical Specification action statement; it is independent of the Completion Time. This Technical Specification is currently in place and will remain in place with the increase CT. Thus, there is no increase in risk due to the CCF aspect of the ICCDP or ICLERP calculations associated with this CT extension. Therefore, the ICCDP/ICLERP for a DG in repair should be limited to consideration of nominal DG failure rates.

The System Engineer at CPSES using actual plant data monitors the CT times. Accordingly, the average time for an DG CT was less than 20 hours as compared to the current Tech Spec allowed CT of 72 hours. This is not expected to change with the extended CT, however, there may be cases where the corrective or repair-type maintenance takes longer than the historical times. Corrective maintenance for the diesel is normally a result of equipment failure during surveillance testing. Prior to running these surveillance tests, the Operations Department is required to ensure that weather conditions (i.e. thunderstorms are threatening the plant) would not impose additional risk during performance of the test. Historically, at CPSES, the majority of the DG repairs occur as a result of failures found during surveillance testing. The DGs are in standby and are only started during surveillance testing or an actual emergency. If a failure occurs on the DG during a surveillance test then the CT for the failure starts when the DG became inoperable due to the surveillance test or the failure whichever came first. This is the justification for not requesting separate CTs for repair or planned maintenance.

Evaluation Criteria

To determine the effect of the proposed allowed Completion Time for restoration of an inoperable DG, the guidance suggested in Regulatory Guides 1.174 and 1.177 (References 1 and 2) was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the DG allowed Completion Time (similar risk metrics were used for the other 6.9 kV AC Components).

ΔCDF_{AVE} = The change in the annual average CDF due to any increase in on-line maintenance unavailability of the DGs that could result from the increased allowed Completion Time. This risk metric is used to compare against the criteria of RG 1.174 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, $CDF_{BASE.}$

$\Delta LERF_{AVE}$ = The change in the annual average LERF due to any increase in on-line maintenance unavailability of the DGs that could result from the increased allowed Completion Time. RG 1.174 criteria are also applied to judge the significance of changes in this risk metric.

ICCDP{DGxY} = The incremental conditional core damage probability with DG *Y* for Unit *X* out-of-service for a period equal to the proposed new allowed Completion Time. This risk metric is used as suggested in RG 1.177 to determine whether a proposed increase in allowed Completion Time will have an acceptable risk impact.

ICLERP{DGxY} = The incremental conditional large early release probability with DG *Y* for Unit *X* out-of-service for a period equal to the proposed new allowed Completion Time. RG 1.177 criteria are also applied to judge the significance of changes in this risk metric.

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) are computed per the definitions from RG 1.177 (Reference 2). In terms of the parameters defined above, the definition of ICCDP is as follows:

$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE})T_{CT}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * (10days) * (365days/year)^{-1}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * 2.74x10^{-2}/year$$

Note that in the above formula 365 days/year is merely a conversion factor to make the units for allowed Completion Time consistent with the units for CDF frequency. The ICCDP values are dimensionless incremental probabilities of a core damage event over a period of time equal to the extended allowed Completion Time. This should not be confused with the evaluation of ΔCDF_{xAVE} in which the CDF is averaged over an 18-month refueling cycle.

Similarly, ICLERP is defined as follows.

$$ICLERP_{xA} = (LERF_{xAOOS} - LERF_{xBASE}) * 2.74x10^{-2}/year$$

Evaluation

The CPSES PRA internal events model was used to evaluate the Diesel Generator Completion Time extension. Similar runs were then conducted for the offsite circuit transformers and safety buses. All of the runs were quantified using the Safety Monitor™ computer program, with any differences described below.

- Baseline CDF with average unavailabilities for all components before and after the proposed DG Completion Time.
- Baseline LERF with average unavailabilities for all components before and after the proposed DG Completion Time.
- Conditional Core Damage Probability with each of components to be evaluated out of service for the proposed Completion Time, in this case a 10 day Completion Time.
- Conditional Large Early Release Probability with each of components to be evaluated out of service for the proposed Completion Time, in this case a 10 day Completion Time.

If the initial analysis of the change in core damage frequency, change in large early release frequency, incremental conditional core damage probability, and incremental conditional large early release probability show a decrease or minimal risk increase, then no additional runs were performed. If any of these parameters shows a significant risk increase, then additional runs were performed as described below. Acceptance criteria for the changes in risk come from Regulatory Guide 1.174.

The Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) with average Test and Maintenance probabilities were calculated for the subject components. The incremental CDF and LERF were calculated while exercising the requested Completion Time. This was done with the Safety Monitor™ computer program. The initial PRA analysis followed the steps listed below. Each step included calculation of the overall change in CDF and LERF as well as the incremental change in CDF and LERF. That is, there were four risk numbers calculated for each step. The overall CDF and LERF are calculated using the average unavailabilities for all components including the DGs. For this calculation, test and maintenance combinations disallowed by Technical Specifications were deleted from the results. The incremental CDF and LERF were calculated by assuming an DG was in maintenance for the entire Completion Time duration. Component outage in the opposite train was not allowed (this would generally lead to Technical Specification 3.0.3 condition). However, component outages in the affected train were allowed and thus two cases were considered. The desirable case is to allow component outages in the affected train and this was the first case analyzed. If this risk was unacceptable, then a second calculation was done with only the DG out for maintenance.

1. Quantitative Full Power Internal Events and Qualitative External Events/Shutdown Check. The Completion Time submittal development initially examined a submittal based on a quantitative analysis of Full Power internal events only. The general argument to be examined for shutdown is that the risk can only improve because the maintenance of the affected component will be moved out of shutdown, thereby increasing the redundancy of available safety equipment for all of shutdown. If the increase in risk due to the increased Completion Time is acceptable based only on the analysis in this step, no further analysis was necessary. If the risk is unacceptable, the following steps were considered.

2. Quantitative Check of Transition Risk to/from Shutdown. The transition risk model used to support this analysis evaluated the impact of corrective maintenance at power requiring shutdown to cold plant conditions to correct. Then the risk associated with on-line maintenance while the corrective action is being performed can be compared with the risk associated with the transition to shutdown with the component being unavailable, plus the risk associated with conducting the maintenance while in cold shutdown, and the risk associated with the transition back to full power.

3. Quantitative Full Power and Shutdown Internal Events and Qualitative External Events. If the Full Power quantitative data (alone) shows a large risk increase, then

the shutdown model was quantified for the modes in which the major DG maintenance activities would have been done. The decrease in risk during shutdown is then quantified to show there is an overall decrease in risk by moving the major DG maintenance activities from shutdown to power operation. As with step 1, this case is analyzed with and without component outages in the affected train.

A similar analysis was performed for removal of a startup transformer from service (30 day) and for removal of a 6.9 kV AC emergency bus (72 hour). The risk increase for all of the 6.9 kV AC components was found to be acceptable, accounting for the shutdown operation, therefore it was unnecessary to develop an alternate power source.

Evaluation of DG Completion Time

The proposed Completion Time evaluated for the diesel generators is 10 days. This evaluation was done using the methodology described above. The equations defined above were used for the evaluation cases described below. A shutdown schedule was evaluated using the appropriate time duration for the plant operating states during which major DG maintenance activities are normally conducted. The shutdown model (MODES 5 and 6) does not evaluate LERF because industry shutdown models do not normally include a calculation of LERF. Little is known for the physics or the dynamics of scenarios resulting in a Large Early Release following shutdown initiating events. The containment is either closed, or can be closed prior to boiling.

The DG Completion Time will continue to be entered for the purpose of routine surveillance testing and other minor maintenance activities. It is anticipated that the DG Completion Time will also be entered once a cycle for a longer period of time (greater than 72 hours) to support major DG maintenance activities. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below.

The Diesel Generator evaluation includes a comparison of the risk associated with a 10-day DG unavailability at power with a 10-day DG unavailability during a normal refueling outage. The refueling outage evaluation assumes that the DG is removed from service upon reaching MODE 5. The schedule used for the evaluation is taken from the 7th Unit 1 refueling outage (1RF07) which is representative of a typical outage. The subscripts for ICCDP and ICLERP shown below represent the case numbers from Table 1, located at the end of this section.

The requirement of Reg. Guide 1.174 is a ΔCDF less than 1E-06 and a ΔLERF less than 1E-07. The requirement of Reg. Guide 1.177 is an ICCDP less than 5E-07 and ICLERP less than 5E-08. The evaluation of the 10 day diesel generator CT meets (without shutdown considerations) the requirements Reg. Guide 1.177 and Reg. Guide1.174. The following are the calculated values for the 10 day CT: ΔCDF of 4.44E-07, ΔLERF of 1.72E-08, ICCDP of 4.44E-07, and ICLERP of 1.72E-08.

If the risk calculated above is compared to the shutdown risk it is apparent that doing the work online has less risk than doing the work during shutdown (see following paragraphs).

At Power,
$ICCDP_{337}$ = 4.44E-07 and $ICLERP_{337}$ = 1.72E-08 MODE 1 Power

During a Refueling Outage,
$ICCDP_{132}$ = 5.30E-07 MODE 5 Cold Shutdown
$ICCDP_{133}$ = 1.79E-06 MODE 5 1' below Flange
$ICCDP_{134}$ = 9.66E-07 MODE 5 Midloop
$ICCDP_{135}$ = 3.69E-07 MODE 6 Refueling Basin Flooded for Core Unload
$ICCDP_{\Sigma 132-135}$ = 3.65E-06

During a Forced Maintenance Shutdown,

$ICCDP_{150}$ = 5.52E-07	$ICLERP_{150}$ = 1.69E-08	MODE 1 Power
$ICCDP_{151}$ = 1.43E-07	$ICLERP_{151}$ = 4.36E-09	MODE 3 Hot Standby (Early)
$ICCDP_{152}$ = 3.01E-08	$ICLERP_{152}$ = 8.46E-010	MODE 4 Hot Shutdown (Early)
$ICCDP_{153}$ = 1.95E-06		MODE 5 Cold Shutdown
$ICCDP_{154}$ = 0	$ICLERP_{154}$ = 0	MODE 4 Hot Shutdown (Late)*
$ICCDP_{155}$ = 0	$ICLERP_{155}$ = 0	MODE 3 Hot Standby (Late)*
$ICCDP_{156}$ = 0	$ICLERP_{156}$ =0	MODE 2 Reactor Startup*

$ICCDP_{\Sigma 150-156} = ICCDP_{MAINTOUT}$

$ICCDP_{MAINTOUT}$ = 2.68E-06 $ICLERP_{MAINTOUT}$ = 2.21E-08 (not including MODE 5)
*Since all equipment is available there is not delta CDF/LERF, therefore there is no incremental change in risk.

As shown in the above calculation, the risk of performing a 10-day diesel generator maintenance with the plant at power (ICCDP = 4.44E-07) is less than the risk of performing the same work with the plant in the early stages of a refueling outage as it is presently performed (ICCDP = 3.65E-06). The risk associated with a plant shutdown to perform emergent corrective maintenance (ICCDP = 2.68E-06) is higher than keeping the plant at power to perform the maintenance. The outage ICCDP and ICLERP values above represent the results for the configurations at various stages of the outage. The final ICCDP and ICLERP represent the summation of the states during the outage. The example above is based on the Train A DG, comparable results were concluded for the Train B DG.

The results of the above analyses allow a comparison of the change in risk for conducting a 10 day DG maintenance at power with the risk of conducting the same DG maintenance during a refueling outage and a forced maintenance. It indicates that the net change in core damage probability is reduced when the diesel generator maintenance is moved from the outage to power. It also indicates that the risk is reduced when corrective maintenance is performed at power versus shutting down to perform the corrective maintenance.

Evaluation of XST1/XST2 Completion Time

The results of the risk evaluation while performing startup transformer maintenance activities at power (full power calculation was performed using the reduced LOOP frequency) meets the requirements for a permanent Tech Spec change in accordance with Reg. Guide 1.174 and 1.177. The risk increase for performing the work at power is considered small, according to Reg Guide 1.174, and within Region II of the acceptance guideline charts. Also the risk increase for performing the work at power is considered small according to Reg. Guide 1.177.

The proposed CT evaluated for the startup transformers is 30 days. This evaluation was done using the methodology described previously. This included reducing the LOOP frequency for plant centered failures, and grid centered failures. The reasoning for this was that work in the switchyard would not be allowed during any maintenance on equipment which could affect offsite power. No credit was taken for severe weather due to the length of the requested CT. The average test and maintenance model was used since plant surveillance will still need to be performed as will emergent work. The restrictions for this CT are to not allow work in the operable switchyard.

It is anticipated that the offsite circuit startup transformer Completion Time will be entered once per cycle to allow for testing or maintenance activities. The amount of time spent in the LCO is expected to last longer than 72 hours when major maintenance activities are required. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below.

Due to power generation demands and overall economic considerations, it is not anticipated for planned outage schedules to include overlapping or simultaneous shutdown of both units. Since the startup transformers feed both units, an evaluation of risk associated with a startup transformer outage with a plant in shutdown was not performed.

If the XST1 startup transformer is taken out of service for maintenance, it affects both units since transformer XST1 functions as a back up to XST2. The same is true for XST2, in which transformer XST2 functions as a back up to XST1. The risk decrease due to the compensatory action that reduces the LOOP frequency and the results are shown below.

XST1	XST2
ΔCDF_{320A1} = 3.62E-07	ΔCDF_{322A2} = 3.70E-07
$\Delta LERF_{320A1}$ = -4.11E-09	$\Delta LERF_{322A2}$ = -3.53E-09
$ICCDP_{320A1}$ = 3.62E-07	$ICCDP_{322A2}$ = 3.70E-07
$ICLERP_{320A1}$ = -4.11E-09	$ICLERP_{322A2}$ = -3.65E-09

The calculation above shows that, due to compensatory measures taken during the startup transformer maintenance, the risk for the plant LERF decreases. The change in CDF associated with this proposed Completion Time extension is considered small, according to the guidelines contained in Regulatory Guide 1.174. Based on the risk graphs in Regulatory Guide 1.174, these values indicate that the change in core damage probability and large early release probability is not considered significant when startup transformer maintenance is completed at power. This reveals that taking a startup transformer out of service, even for an extended period of time, is not risk significant, in part, because of the redundancy and diversity of off site power at CPSES.

Evaluation of 1EA1/1EA2 and 2EA1/2EA2

The proposed Completion Time evaluated for the 6.9 kV AC buses 1EA1 and 1EA2 is 72 hours. This evaluation was done using the methodology described earlier in the evaluation. The equations defined previously were used for the evaluations cases described below.

A 72 hour Completion Time extension was assessed for the 6.9 kV AC safety buses from the current 8-hour limit (Technical Specification 3.8.9). It is anticipated that this Completion Time will be entered to support repair activities.

The 6.9 kV AC bus evaluation includes a comparison of a 72-hour bus outage at power with the transition and shutdown risk associated with a forced shutdown to perform repairs to the bus. The forced outage evaluation includes plant shutdown with the bus inoperable and includes the transition risk associated with plant restart to power.

As shown below, the risk associated with a plant shutdown to perform repair activities is an order of magnitude higher than keeping the plant at power to perform the maintenance. The forced outage ICCDP and ICLERP values below represent the results for configurations at various stages of the outage. The final ICCDP and ICLERP represent the summation of states during the outage and are the total risk associated with the component being out of service. The subscripts for ICCDP and ICLERP shown below represent case numbers from Table 1 located at the end of this section.

At Power,
$ICCDP_{321}$ = 3.37E-05 and $ICLERP_{321}$ = 5.07E-06

During a Forced Maintenance Shutdown for the following plant states,
$ICCDP_{160}$ = 6.60E-06 $ICLERP_{160}$ =9.85E-07 MODE 1 Power
$ICCDP_{161}$ = 9.62E-05 $ICLERP_{161}$ = 1.21E-06 MODE 3 Hot Standby (Early)
$ICCDP_{162}$ = 6.93E-06 $ICLERP_{162}$ = 2.08E-07 MODE 4 Hot Shutdown (Early)
$ICCDP_{163}$ = 5.41E-05 MODE 5 Cold Shutdown
$ICCDP_{154}$ = 0
$ICLERP_{154}$ = 0 MODE 4 Hot Shutdown (Late)*
$ICCDP_{155}$ = 0 $ICLERP_{155}$ = 0 MODE 3 Hot Standby (Late)*
$ICCDP_{156}$ = 0 $ICLERP_{156}$ =0 MODE 2 Reactor Startup*

$ICCDP_{\Sigma 160\text{-}163+\Sigma 154\text{-}156} = ICCDP_{MAINTOUT}$

$ICCDP_{MAINTOUT}$ = 7.72E-05 $ICLERP_{MAINTOUT}$ = 2.40E-06(not including MODE 5)
*Since all equipment is available there is no delta CDF/LERF, therefore there is no incremental change in risk.

Results of these analyses allow a comparison of the change in risk for conducting a 72 hour maintenance outage on 6.9kV bus at power with the risk of conducting the same maintenance during a forced maintenance outage. It indicates that the net change in core damage probability is reduced when the 6.9kV bus maintenance is completed at power rather than during a forced shutdown and therefore presents a lower overall risk.

Sensitivity Studies

For this submittal, TXU reviewed the Loss of Offsite Power and Station Blackout sequences, and the RCP seal LOCA modeling. The associated sensitivity studies are summarized below.

Sensitivity Cases 110A and 110B

Sensitivity cases 110A and 110B were run to determine the effect of a higher Loss of Offsite Power initiating event frequency. The normal value for INIT-X3 is 0.0395/year and for the sensitivity analysis, this value was changed to 0.052/year. The value used for the sensitivity is the frequency used by another plant in this region and is on the higher end of the Loss of Offsite Power initiating event frequencies cited in NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," November 1998. The results of this sensitivity show that the CDF rises as the Loss of Offsite Power initiator frequency is increased. A higher loss of offsite power initiating event frequency affects both full power and shutdown. Since both the full power and shutdown risk increase linearly, the delta between full power and shutdown risk remains constant. Thus, an increased loss of offsite power initiating event frequency does not change the conclusions of this analysis and the proposed Completion Time extensions are supported.

Sensitivity Cases 111A and 111B

Sensitivity cases 111A and 111B were run to determine the effect of implementing the Brookhaven RCP Seal LOCA model. The nominal value of the basic events associated with various seal failure modes were change to reflect the values defined in Brookhaven RCP Seal LOCA model. It was confirmed that the existing RCP seal LOCA model contains all of the failure modes identified in the USNRC-approved Brookhaven RCP Seal LOCA model. The impact of using the Brookhaven RCP Seal LOCA model was then examined as a sensitivity analysis. This sensitivity analysis showed that if the Brookhaven RCP Seal LOCA model is used there is an increase in the baseline and configuration specific CDF when the DG is taken out of service. This results in a small increase in the risk metrics; however, that risk increase remains less than the change in risk if the major DG maintenance activities were completed during shutdown. That is, the shifting of DG maintenance from shutdown to full power still results in a risk advantage. Thus, the conclusions of this study remain unchanged and the proposed Completion Time extensions are supported.

4.2.2 Restriction on High Risk Configuration

To avoid or reduce the potential for risk-significant configurations from either emergent or planned work, CPSES has put in place a set of administrative guidelines that go beyond the limitations set forth in the plant Technical Specifications. These guidelines control configuration risk by assessing the risk impact of equipment out-of-service during all modes of operation to ensure that the plant is always being operated within acceptable risk guidelines.

CPSES employs a conservative approach to at power maintenance. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals and/or compensatory actions. The assessment process further minimizes risk by restricting the number and combination of systems/trains allowed to be simultaneously unavailable for scheduled work.

Unplanned or emergent work activities are factored into the plant's actual and projected condition, and the level of risk is evaluated. Based on the result of this evaluation, decisions pertaining to what action, if any, are required to achieve an acceptable level of risk (component restoration or invoking compensatory measures) are made. The unplanned or emergent work activities are also evaluated to determine impact on planned activities and the affect the combinations would have on risk.

Technical Specification 5.5.18, "Configuration Risk Management Program (CRMP)," will apply to this license amendment request and is repeated below for information:

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed allowed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

Risk-Significant Components Given A 6.9kv AC Component Is Out Of Service

This list of risk significant components associated with each of the 6.9kV components being considered for Completion Time extension was obtained by using the Safety Monitor™ "Important Operable Components" option. This option identifies those components whose risk values contribute the most to the overall risk of the configuration. The category of components are summarized below, rather than presenting a long list of individual component identifiers.

Risk Significant Components Given a Diesel Generator is out of Service

The following provides a list of the risk significant components and /or systems given that a Diesel Generator is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their Risk Achievement Worth (RAW) value (i.e., the increase in risk if the component is assumed to be failed at all times, expressed as a ratio of assumed risk to baseline risk). These are not necessarily in ranked order.

- Electric Power - opposite train motive and control power
- Refueling Water Storage Tank - Tank and its associated discharge valves
- Service Water - opposite train
- Diesel Generator - opposite train

Risk Significant Components Given a Startup Transformer is out of Service

The following provides a list of the risk significant components and /or systems given that a Startup Transformer is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their RAW value. These are not necessarily in ranked order.

- Electric Power – AC and DC power distribution, both trains
- The redundant Startup Transformer
- Service Water - Both trains
- Diesel Generators

Risk Significant Components Given a 6.9kV Bus is out of Service

The following provides a list of the risk significant components and /or systems given that a 6.9 kV bus is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their RAW value. These are not necessarily in ranked order.

- Electric Power - opposite train motive and control power
- Refueling Water Storage Tank - Tank and its associated discharge valves
- Service Water - opposite train
- Diesel Generator - opposite train
- Component Cooling Water – opposite train
- Charging System – Opposite Train
- Turbine Driven AFW Pump
- RHR System – Opposite Train

Summary of Results and Conclusions of Risk Evaluation

The probabilistic evaluations presented above support the Allowed Outage Time (CT) extension request for 6.9kV AC components including the Diesel Generators (DGs), 6.9kV AC startup transformers, and 6.9kV AC safety buses. The results of the evaluations presented herein justify extending the Allowed Outage Times for these components.

The results of the risk evaluation of the 10 day diesel generator CT meet the requirements of Regulatory Guide (RG) 1.177 and RG 1.174 (without shutdown considerations). The following are the calculated values for the 10 day CT: ΔCDF of 4.44E-07, ΔLERF of 1.72E-08, ICCDP of 4.44E-07, and ICLERP of 1.72E-08. The requirement of RG 1.174 is a ΔCDF less than 1E-06 and a ΔLERF less than 1E-07. The requirement of RG 1.177 is an ICCDP less than 5E-07 and ICLERP less than 5E-08.

If the risk calculated above is compared to the shutdown risk it is apparent that doing the work online has less risk than doing the work during shutdown (see following paragraphs).

In addition, the risk of performing a 10-day diesel generator maintenance activity at power (full power calculation was performed using the reduced LOOP frequency for the time that the diesel was out of service and no maintenance allowed) is less than the risk of performing the same work with the plant in the early stages of a refueling outage (as it is presently performed). The difference in risk (ICCDP) for performing the DG maintenance on line (4.44E-07) versus during refueling (3.65E-06) is 3.21E-06. This indicates a large increase in risk, when the work is performed during a shutdown versus at power. The risk associated with a plant shutdown to perform emergent corrective maintenance on the DG is considerably higher than keeping the plant at power to perform the maintenance. The risk of performing a 10 day diesel generator unavailability with the plant at power (ICCDP=4.44E-07) is less than the risk of performing the same work with a forced shutdown (ICCDP=2.68E-06). The expected timeframe for performing online DG maintenance is 7 days. For this timeframe, performing the work at power is considered small, according to Reg Guide 1.174, and within Region II of the acceptance guideline charts. Also the risk increase for performing the work at power is considered small according to Reg. Guide 1.177. Note that this evaluation compares design basis to design basis and does not credit the alternate power diesels used during outages at CPSES.

The results of the risk evaluation while performing startup transformer maintenance activities at power (full power calculation was performed using the reduced LOOP frequency) meets the requirements for a permanent Tech Spec change in accordance with Reg. Guide 1.174 and 1.177. The risk increase for performing the work at power is considered small, according to RG 1.174, and within Region II of the acceptance guideline charts. Also the risk increase for performing the work at power is considered small according to RG 1.177. This reveals that taking a startup transformer out of service, even for an extended period of time, is not risk significant because of the redundancy and diversity of off site power at CPSES.

If a startup transformer is taken out of service for maintenance, it affects both units since transformer XST1 functions as a backup to XST2. The calculated risk for power is ICCDP= 3.62E-07, ICLERP=-4.11E-09 for XST1, and ICCDP=3.70E-07, ICLERP=-3.53E-09 for XST2. The increase in risk results in an additional CDF contribution of 3.62E-07/year for XST1 and 3.70E-07/year for XST2. The increase in risk results in an additional LERF contribution of approximately –4.11E-09/year forXST1 and –3.53E-09 for XST2. These results are influenced by the compensatory actions taken during the maintenance period. The risk change associated with this proposed CT extension is considered small, according to the guidelines contained in RG 1.174. Based on the risk graphs in RG 1.174, these values indicate that the change in core damage probability and large early release probability is not considered significant when startup transformer maintenance is completed at power. Also the risk change for performing the work at power is considered small according to RG 1.177.

The risk associated with a plant shutdown to perform repairs on the 6.9 kV AC safety bus is nearly twice as high as keeping the plant at power to perform the maintenance. The full power evaluation included reducing the LOOP for plant centered failures and not working on the AFW system. The forced outage evaluation includes evaluation of the shutdown with the bus unavailable and also includes the transition risk associated with plant restart to power. The results of the analyses allow a comparison of the change in risk for conducting a 72 hour maintenance outage on 6.9kV bus at power with the risk of conducting the same maintenance during a forced maintenance outage. It indicates that the change in core damage probability is reduced when the 6.9kV bus maintenance is completed at power (3.37E-05) rather than during a forced shutdown (7.72E-05) and therefore presents a lower overall risk.

The proposed CTs have been analyzed individually in accordance with RG 1.177. The requirement of the Regulatory Guide to look at the cumulative affects of these CT was examined.

However, these pieces of equipment (diesel generator, Startup transformer, and 6.9 kv bus) will not be out of service for planned maintenance at the same time when the plant is at power. Therefore the cumulative effects of these CTs were not considered.

Summary

TXU Energy has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Table 1 – CPSES 6.9 kV AC Completion Time PRA Results Summary

CASE ID	COMPONENT	CDF	LERF	ICCDP	ICLERP	Delta CDF	Delta LERF	COMMENTS
337	A Train DG: 1DG1, 2DG1 with 10 day CT	1.71E-05	5.61E-07	4.44E-07	1.72E-08	4.44E-07	1.72E-08	Full Power calculated with 1DG1 inoperable. All TM events 0. Reduced LOOP frequency due to plant centered, grid centered and severe weather analysis
132-135		7.04E-03	0.00E+00	3.65E-06	0.00E+00	1.17E-03	N/A	Refueling Outage calculated with 1EA1 DG inoperable when MODE 5 starts.
150-156		6.05E-04	1.21E-05	2.68E-06	2.21E-08	2.97E-04	5.74E-06	Forced Maintenance Outage to Cold Shutdown calculated with 1EA1 DG inoperable.
		The risk increase is considered small, according to Reg Guide 1.174, within Region II of the acceptance guidelines charts. Also performing the maintenance at power (MODE 1) rather than during shutdown (refueling outage) presents a lower overall risk and thus shifting the DG-A maintenance to online is acceptable.						
331	B Train DG: 1DG2, 2DG2 with 10 day CT	1.71E-05	5.61E-07	4.41E-07	1.69E-08	4.41E-07	1.69E-08	Full Power calculated with 1DG1 inoperable. All TM events 0. Reduced LOOP frequency due to plant centered, grid centered and severe weather analysis
142-145		7.02E-03	0.00E+00	3.59E-06	0.00E+00	1.15E-03	N/A	Refueling calculated with 1EA2 DG inoperable when MODE 5 starts.
250-253 & 154-156		6.06E-04	1.21E-05	2.60E-06	2.21E-08	2.98E-04	5.76E-06	Forced Maintenance Outage to Cold Shutdown calculated with 1EA2 DG inoperable.
		The risk increase is considered small, according to Reg Guide 1.174, within Region II of the acceptance guidelines charts. Also performing the maintenance at power (MODE 1) rather than during shutdown (refueling outage) presents a lower overall risk and thus shifting the DG-A maintenance to online is acceptable.						

CASE ID	COMPONENT	CDF	LERF	ICCDP	ICLERP	Delta CDF	Delta LERF	COMMENTS
315A	XST1 Transformer with 30 day CT Unit 1	1.71E-05	5.40E-07	3.62E-07	-4.11E-09	3.62E-07	-4.11E-09	Full Power, Unit 1, calculated with XST1 Transformer inoperable, average TM, Reduced LOOP frequency (Plant and Grid Centered only).
315A	XST1 Transformer with 30 day CT Unit 2	1.60E-05	5.29E-07	-2.30E-07	-6.66E-09	-2.30E-07	-6.66E-09	Full Power, Unit 2, calculated with XST1 Transformer inoperable, average TM, Reduced LOOP frequency (Plant and Grid Centered only).
105C	XST2 Transformer with 30 day CT Unit 1	1.71E-05	5.40E-07	3.70E-07	-3.53E-09	3.70E-07	-3.53E-09	Full Power, Unit 1, calculated with XST2 Transformer inoperable, average TM, Reduced LOOP frequency (Plant and Grid Centered only).
105C	XST2 Transformer with 30 day CT Unit 2	1.60E-05	5.29E-07	-2.30E-07	-7.15E-09	-2.30E-07	-7.15E-09	Full Power, Unit 2, calculated with XST2 Transformer inoperable, average TM, Reduced LOOP frequency (Plant and Grid Centered only).
321	6.9kV AC Bus 1EA1, 2EA1 with 72 hour CT	5.04E-05	5.61E-06	3.37E-05	5.07E-06	3.37E-05	5.07E-06	Full Power calculated with 6.9kv bus 1EA1 inoperable, all TM events 0. Reduced LOOP frequency due to plant centered.

CASE ID	COMPONENT	CDF	LERF	ICCDP	ICLERP	Delta CDF	Delta LERF	COMMENTS
160-163 & 154-156		3.27E-02	1.35E-03	7.72E-05	2.40E-06	3.24E-02	1.35E-03	Forced Maintenance Outage to Cold Shutdown calculated with 1EA1 6.9kV AC bus inoperable.
A Bus		Performing the maintenance at power rather than during shutdown presents a lower overall risk.						
323	6.9kV AC Bus 1EA2, 2EA2 with 72 hour CT	3.88E-05	9.70E-07	2.21E-05	4.27E-07	2.21E-05	4.26E-07	Full Power calculated with 6.9kv bus 1EA2 inoperable, all TM events 0. Reduced LOOP frequency (Plant Centered only).
260-263 & 154-156		3.28E-02	1.29E-03	8.00E-05	2.28E-06	3.24E-02	1.29E-03	Forced Maintenance Outage to Cold Shutdown calculated with 1EA2 6.9kV AC bus inoperable.
B Bus.		Performing the maintenance at power rather than during shutdown presents a lower overall risk						
Sensitivity Cases								
110A	All equipment operable, all TM events 0, INIT-X3 set to 5.2E-02	1.25E-05	4.97E-07					Sensitivity Full Power Baseline, All Equipment operable, all TM events 0. LOOP I.E. set to 5.2E-02
110B	All equipment operable, average TM. INIT-X3 set to 5.2E-02	1.68E-05	5.44E-07					Sensitivity Full Power Baseline, All Equipment operable, average TM. LOOP I.E. set to 5.2E-02
111A	(Baseline CDF & LERF Sensitivity)	1.52E-05	5.81E-07					Sensitivity Full Power Baseline with BNL Seal LOCA model. All Equipment operable, all TM events 0. GSFSMALL set to 0.2. 53% increase in CDF and 50% increase in LERF for higher GSFSMALL value.
111B	(Baseline CDF & LERF Sensitivity)	3.32E-05	8.37E-07					Sensitivity Full Power Baseline with BNL Seal LOCA model. All equipment operable, average TM. GSFSMALL set to 0.2. 52% increase in CDF and 54% increase in LERF for higher GSFSMALL value.

CASE ID	COMPONENT	CDF	LERF	ICCDP	ICLERP	Delta CDF	Delta LERF	COMMENTS
Sensitivities with LSP reduced								
319	MODE 5FLN with DG A out of service	3.10E-03	0.00E+00	1.96E-05	0.00E+00	5.10E-04	0.00E+00	
320	No test and maintenance, MODE 1 with XST1 unavailable for 30 days	1.07E-05	4.49E-07	2.79E-07	4.27E-09	2.79E-07	4.27E-09	LSP was reduced due to reevaluation of plant centered faults
321	No test and maintenance, MODE 1 with 1EA1 unavailable 72 hours	4.42E-05	5.51E-06	3.38E-05	5.07E-06	3.38E-05	5.07E-06	LSP was reduced due to reevaluation of plant centered faults.
322	No test and maintenance, MODE 1 with XST2 unavailable for 30 days	1.03E-05	4.44E-07	-5.18E-08	-1.48E-09	-5.18E-08	-1.48E-09	LSP was reduced due to reevaluation of plant centered faults.
323	No test and maintenance, MODE 1 with 1EA2 unavailable for 72 hours	3.25E-05	8.72E-07	2.21E-05	4.27E-07	2.21E-05	4.27E-07	LSP was reduced due to reevaluation of plant centered faults.
337	No test and maintenance, DG A unavailable for 10 days	1.71E-05	5.61E-07	4.44E-07	1.72E-08	4.44E-07	1.72E-08	LSP was reduced due to reevaluation of plant centered, grid centered, and severe weather induced faults.
331	No test and maintenance, DG B unavailable for 10 days	1.71E-05	5.61E-07	4.41E-07	1.69E-08	4.41E-07	1.69E-08	LSP was reduced due to reevaluation of plant centered, grid centered, and severe weather induced faults.

4.3 PRA Quality

CPSES has followed a rigorous process in the development and maintenance of a PRA Model. The process has resulted in a level of quality allowing enhancement of safety through risk insights and regulatory applications. Some characteristics of this process include independent reviews, the WOG peer review, detail and integration of PRA elements, supportable assumptions, updates to reflect industry and plant specific data, and thorough documentation. CPSES has also implemented program controls to ensure as-built plant changes (including modifications, procedure changes, etc.) are routinely evaluated and are accurately reflected in the current model.

The following update milestones summarize the development and improvement of the CPSES PRA since its submittal to satisfy NRC Generic Letter 88-20 requirements. This summary demonstrates the analysis is sufficient to adequately provide risk insights in support of regulatory applications. The results of this history and the current evaluation for suitability in this application show that the CPSES PRA is appropriate for use in the CPSES Risk-Informed extension of allowed Completion Times for 6.9 kV AC components.

- CPSES revised the top logic (event tree/fault tree interface) to support a linked fault tree model substantially reducing the effort required to requantify the PRA.
- A second update resulted in changes to make the model compatible with Safety Monitor™.
- Further revision ensured the PRA system level models were consistent, and that the models were symmetric between trains. This update also incorporated operational data in order to update component failure rates, initiating event frequencies, human error probabilities, and recovery probabilities.
- Key enhancements have included Thermal-Hydraulics analysis for accident sequences, application of systematic recovery analysis, integration of ISLOCA sequences and changes to RCP seal modeling.
- The most recent update added logic to reflect dual unit differences.

The CPSES PRA has been used in support of several submittals to the USNRC, including Risk Informed IST, Risk Informed ISI and several AOT/CompletionTime Extensions. NRC reviews associated with these submittals have found the quality of the CPSES PRA acceptable.

4.4 "Second" Completion Times

As discussed in Subsection 3.2, the second Completion Time is included in the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions of Inoperability during any single continuous failure to meet the LCO. The intent of the second Completion Time is to preclude entry into and out of the Actions for an indefinite period of time by providing a limit on the amount of time that the LCO could not be met for various combinations of Conditions.

The new completion time for TS 3.8.1 Required Action A.3 (30 days) and TS 3.8.1 Required Action B.4 (10 days) provides an additional second Completion time of 40 days from discovery of failure to meet the LCO. The second Completion Times in TS 3.8.9 are revised from "16 hours from discovery of failure to meet LCO" to "80 hours from discover of to failure to meet LCO." The second Completion Times are an administrative limit intended to prevent the plant from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO (i.e., "flip flopping"). The second Completion times are generally the sum of the component Completion Times that could be successively entered. This administrative limit is calculated without regard to the method used to determine the component Completion Times. Therefore, an extension of one of the component Completion Times will result in a corresponding extension of the "modified time zero" Completion Time.

4.5 Summary and Conclusions

The current Completion Times associated with inoperable AC power source(s) are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources.

The proposed Completion Times will continue to provide adequate protection of public health and safety and common defense and security as described below. The changes advance the objectives of the NRC's Probabilistic Risk Assessment (PRA) Policy Statement (Reference 19), for enhanced decision-making and result in a more efficient use of resources and reduction of unnecessary burden. Implementation of the proposed Completion Times will provide the following benefits.

- Allow increased flexibility in the scheduling and performance of DG or startup transformer (ST) maintenance.
- Allow better control and allocation of resources. Allowing on-line maintenance, including overhauls, provides the flexibility to focus more quality resources on any required or elected DG or ST maintenance.
- Avert unplanned plant shutdowns and minimize the potential need for requests for Notice of Enforcement Discretion (NOED). Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve DG, ST, or 6.9 kV AC safety bus availability during shutdown modes or Conditions. This will reduce the risk associated with DG maintenance and the synergistic effects on risk due to DG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.
- Permit scheduling of DG or ST overhauls within the requested Completion Time extension period.
- Permit emergency repair of 6.9 kV AC safety bus at power.

The results of TXU probabilistic evaluations support extension of the existing Completion Time for all affected components. The Completion Time for the Diesel Generators may be extended to 10 days. The Completion Time for the offsite circuit startup transformers may be extended to 30 days. The Completion Time for the 6.9 kV AC safety buses may be extended to 72 hours. Details of the analysis are contained in Section 4.0 of this report.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No significant Hazards Determination

TXU Energy has evaluated whether or not a significant hazards consideration is involved with the proposed changes by focusing on the three standards set forth in 10CFR50.92 as discussed below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

   The proposed Technical Specification changes do not significantly increase the probability of occurrence of a previously evaluated accident because the 6.9 kV AC components (i.e., Diesel Generators (DGs), startup transformers (STs), and safety-related (Class 1E) busses) are not initiators of previously evaluated accidents involving a loss of offsite power. The proposed changes to the Technical Specification Action Completion Times do not affect any of the assumptions used in the deterministic or the Probabilistic Safety Assessment (PSA) analysis

   The proposed Technical Specification changes will continue to ensure the 6.9 kV AC components perform their function when called upon. Extending the Technical Specification Completion Times to 10 days does not affect the design of the DGs, the operational characteristics of the DGs, the interfaces between the DGs and other plant systems, the function, or the reliability of the DGs. Thus, the DGs will be capable of performing either accident mitigation function and there is no impact to the radiological consequences of any accident analysis.

   To fully evaluate the effect of the changes to the 6.9 kV AC components, Probabilistic Safety Analysis (PSA) methods and deterministic analysis were utilized. The results of this analysis show no significant increase in the Core Damage Frequency.

   The Configuration Risk Management Program (CRMP) in Technical Specification 5.5.18 is an administrative program that assesses risk based on plant status. Adding the requirement to implement the CRMP for Technical Specification 3.8.1 and 3.8.9 requires the consideration of other measures to mitigate consequences of an accident occurring while a 6.9 kV AC component is inoperable.

2. Do the proposed changes create the possibility of a new or different kind of

accident from any accident previously evaluated?

Response: No

The proposed changes do not result in a change in the manner in which the electrical distribution subsystems provide plant protection. There are no design changes associated with the proposed changes. The changes to Completion Times do not change any existing accident scenarios, nor create any new or different accident scenarios.

The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. In addition, the changes do not impose any new or different requirements or eliminate any existing requirements. The changes do not alter assumptions made in the safety analysis. The proposed changes are consistent with the safety analysis assumptions and current plant operating practice.

3. Do the proposed changes involve a significant reduction in a margin of safety?

Response: No

The proposed changes do not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined. The safety analysis acceptance criteria are not impacted by these changes. The proposed changes will not result in plant operation in a configuration outside the design basis. The calculated impact on risk is insignificant and is consistent with the acceptance criteria contained in Regulatory Guides 1.174 and 1.177. The proposed activities involves changes to certain Completion Times. The proposed changes remain bounded by the existing Surveillance Requirement Completion Times and therefore have no impact to the margins of safety.

Based on the above evaluations, TXU Energy concludes that the activities associated with the above described changes present no significant hazards consideration under the standards set forth in 10CFR50.92 and accordingly, a finding by the NRC of no significant hazards consideration is justified.

5.2 Regulatory Safety Analysis

<u>Applicable Regulatory Requirements / Criteria</u>

USNRC, "Final Policy Statement on Technical Specification Improvements for Nuclear Power Reactors," Federal Register, 58 FR 39132, July 22, 1993.

USNRC, 10 CFR 50.36, "Technical Specifications," Federal Register, 60 FR 36953, July

19, 1995.

NUREG 1431, "Standard Technical Specifications Westinghouse Plants, Rev. 1, April 1995)

GDC 5 - Sharing of Structures, Systems, and Components, "Structures, systems, and components important to safety shall not be shared between nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining unit."

GDC 17 - An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to ensure 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 onsite electric power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure. 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 electrical power circuit, to ensure 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 ensure that core cooling, containment integrity, and other vital safety functions are maintained.
Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies.

GDC 18 – Inspection and Testing of Electric Power System, Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system [1]."

NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems."

NRC Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies."

NRC Regulatory Guide 1.53, dated June 1973, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems."

NRC Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions."

NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems."

NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants."

NRC Regulatory Guide 1.93, "Availability of Electric Power Sources," December 1974

NRC Regulatory Guide 1.108, "Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1 (8/77)

NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988

5.2.1 Analysis

GDC 17:

The primary requirement of concern is GDC 17.

The safety-related systems are designed with sufficient capacity, independence, and redundancy to ensure performance of their safety functions assuming a single failure. The offsite electrical power system also provides 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 and the diesel generator starts should the alternate source not return power to the Class 1E buses. 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.

Two independent diesel generators and their distribution systems are provided for each unit to supply power to the redundant onsite AC Power System. Each diesel generator and its distribution system is designed and installed to provide a reliable source of redundant onsite-generated (standby) AC power and is capable of supplying the Class 1E loads connected to the Class 1E bus which it serves.

Safety Guide 6:

These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems," (Reference 11) as discussed in Appendix 1A(B) of the FSAR (Reference 3) is not affected by this change.

Redundant parts within the AC and DC systems are physically and electrically independent to the extent that a single event or single electrical fault can not cause a loss of power to both Class 1E load groups.

Safety Guide 9:

These proposed changes do not add any loads to the DGs; therefore, the selection of the capacity of the DGs for standby power systems and conformance to the applicable Sections of Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies," (Reference 12) are not affected by this change.

Regulatory Guide 1.93:

The current Completion Times associated with inoperable AC power source(s) are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974, (Reference 6) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., Completion Times) that the NRC considers acceptable if the number of available AC power sources are less than the LCO. Specifically, "if the available ac power sources are one less than the number required by the TS LCO, power operation may continue for a period that should not exceed 72 hours if the system stability and reserves are such that a subsequent single failure (including a trip of the unit's generator, but excluding an unrelated failure of the remaining offsite circuit if this degraded state was caused by the loss of an offsite source) would not cause total loss of offsite power."

Conformance with Regulatory Guide 1.93 is affected by these proposed change.

According to Regulatory Guide 1.93, operation may continue with one offsite circuit inoperable for a period that should not exceed 72 hours. Aside from the exception discussed above, the station currently conforms to the RG. If the proposed change is approved, the stations will continue to conform to RG 1.93 with the exception that, (1) for the proposed Startup Transformer preventive maintenance outage, the allowed Completion Time for restoration of an offsite circuit will be increased to 30 days, and (2) for the DG preventive maintenance outage, the allowed Completion Time for restoration of an DG will be increased to 10 days.

The proposed extended Completion Times do not change the compliance with the above general design criteria and regulatory requirement, other than the deviations from Regulatory Guide 1.93 and NUREG 1431 (Reference 20) discussed above.

Other Requirements/Criteria:

Commitments to other key design criteria applicable to onsite electrical systems that would be unaffected by these proposed changes include: Regulatory Guide 1.53, dated June 1973, titled, "Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems," (Reference 14) Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions," (Reference 15) and Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 16).

As discussed in the previous section, conformance with relevant regulatory guidance is not affected by this proposed change, with the exception of Regulatory Guide (RG) 1.93. The RGs cited in the previous section endorse industry standards.

5.2.2 Conclusion

The technical analysis performed by TXU Energy in Section 4, "Technical Analysis," demonstrates the ability of the 6.9 kV AC components (diesel generator, startup transformer, and safety bus) to perform their safety function. The increased Completion Times continue to comply with the above regulatory requirements.

Safety analysis acceptance criteria in the FSAR continue to be met. The proposed changes do not affect any assumptions or inputs to the safety analysis.

6.0 ENVIRONMENTAL CONSIDERATION

TXU Energy has determined that the proposed amendment would change requirements with respect to the installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. TXU Energy has evaluated the proposed changes and has determined that the changes do not involve (1) a significant hazards consideration, (2) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (3) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criterion for categorical exclusion set forth in 10CFR51.22(c)(9). Therefore, pursuant to 10CFR51.22(b), an environmental assessment of the proposed change is not required

7.0. REFERENCES

1. NRC Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998.
2. NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," August 1999.
3. Comanche Peak Steam Electric Station Final Safety Analysis Report, Docket Nos. 50-445 and 50-446.
4. (a)WOG Letter OG-01-139 from WOG to NRC, dated June 15, 2001, Transmitted WCAP-15622, "Risk-Informed Evaluation of Extension to AC Electrical Power System Completion Times" Non-Proprietary Class 3 (MUHP-3010), May 2001 by Letter WOG-01-137, dated June 15, 2001
   (b) NRC Request for Additional Information on WCAP-15622, Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" dated January 17, 2002.
   (c) NRC Letter from Drew Holland to Gordon Bischoff, "Request for Additional Information on WCAP-15622, Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" dated February 28, 2002.
   (d) WOG Letter OG-xx-xxx from WOG to NRC, Robert H. Bryan to Document Control Desk, dated November 2002, "Transmittal of RAI Responses for WCAP-15622, 'Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times'"
   (e) NRC Letter from Drew Holland to Gordon Bischoff, "Request for Additional Information on WCAP-15622, Revision 0, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times," July 22, 2003. (TAC NO. MB2257)
5. Industry/ Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-417, Rev 0, AC Electrical Power System Completion Times
6. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974.
7. Industry/ Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-283, Rev 3, Modify Section 3.8 Mode restriction Notes
8. Industry/ Technical Specification Task Force (TSTF) Standard Technical Specification (STS) change TSTF-439, Rev 1, Eliminate Second Completion Times Limiting Time From Discovery of Failure to Meet an LCO
9. CE NSPD 1045, "Joint Applications Report, Modification to the Containment Spray System,

and the Low Pressure Safety Injection System Technical Specifications," (TSTF-409)
10. NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988
11. NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems."
12. NRC Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies."
13. NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants."
14. NRC Regulatory Guide 1.53, dated June 1973, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems."
15. NRC Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions."
16. NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems."
17. Letter number WO 03-0057, from Britt T. McKinney to NRC, dated October 30, 2003, Docket No. 50-482: Revision to Technical Specifications – Extensions of AC Electrical Power Distribution Completion Times
18. NUREG CR/5496, Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996, November 1998
19. NRC's Probabilistic Risk Assessment (PRA) Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16,
20. NUREG 1431, "Standard Technical Specifications Westinghouse Plants, Rev. 1, April 1995
21. WCAP-10541, "Reactor Coolant Pump Seal Performance Foloowing a Loss of All AC Power"

ATTACHMENT 2 to TXX-03137

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

Pages	**3.8-2**
	3.8-4
	3.8-38
	3.8-39
	5.0-28

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND ——NOTE—— In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. A.2 Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND A.3 Restore required offsite circuit to OPERABLE status. 30 days 40	72 hours AND 6 days from discovery of failure to meet LCO ~~OR~~ ~~21 days for a one time preventive maintenance outage on Startup Transformer XST2 to be completed by February 28, 2002~~ 88 88

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	B.4 Restore DG to OPERABLE status. 40	72 hours 10 days AND 6 days from discover of failure to meet LCO discovery
C. Two required offsite circuits inoperable.	---NOTE--- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ---	
	C.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND	
	C.2 Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	72 8 hours AND 80 16 hours from discovery of failure to meet LCO
B. One AC vital bus subsystem inoperable.	B.1	Restore AC vital bus subsystem to OPERABLE status.	2 hours AND 80 16 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 80 16 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

FOR INFORMATION ONLY

5.5 Programs and Manuals (continued)

5.5.17 Technical Requirements Manual (TRM)

The TRM contains selected requirements which do not meet the criteria for inclusion in the Technical Specification but are important to the operation of CPSES. Much of the information in the TRM was relocated from the TS.

Changes to the TRM shall be made under appropriate administrative controls and reviews. Changes may be made to the TRM without prior NRC approval provided the changes do not require either a change to the TS or NRC approval pursuant to 10 CFR 50.59. TRM changes require approval of the Plant Manager*. 84

5.5.18 Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

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* Duties may be performed by the Vice President of Nuclear Operations if that organizational position is assigned.

ATTACHMENT 3 to TXX-03137

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES (MARK-UP)
(For Information Only)

Pages	**B 3.8-7**
	Insert A
	B 3.8-10
	Insert B
	B 3.8-29
	Insert C
	B 3.8-78
	B 3.8-79
	Insert D
	B 3.8-80
	B 3.8-81
	B 3.8-82
	B 3.8-83
	B 3.8-84
	Insert E

BASES

ACTIONS (continued)

A.3

Insert A

~~According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.~~

~~The 72 hour 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 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~~ 10 days. This could lead to a total of ~~144 hours~~ 40 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~~ 30 days (for a total of ~~9~~ 50 days) allowed prior to complete restoration of the LCO. The ~~6~~ 40 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 ~~72 hour~~ 30 days and ~~6~~ 40 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

~~A temporary Completion Time is connected to the Completion Time requirements above (72 hours AND 6 days from discovery of failure to meet LCO) with an "OR" connector. The temporary completion time is 21 days and applies to the performance of preventive maintenance on Startup Transformer XST2. The temporary Completion Time of 21 days expires on February 28, 2002. If, during the conduct of the prescribed XST2 maintenance outage, should any combination of the remaining operable AC Sources be determined inoperable (on an individual unit bases), current TS requirements would apply for any additional conditions which are entered.~~ 17

(continued)

Insert A (page B 3.8-7)

In Condition A, the remaining offsite circuit is 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.

This Completion Time (CT) is intended to be used for repair and preventive maintenance activities. With regard to repair, historically, at Comanche Peak the average duration of repair activities is significantly less than the CT of 30 days, though there may be more than one such entry per year. The foregoing does not imply that, if necessary, Comanche Peak will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. A completion time approaching 30 days also allows for declaring or rendering a startup transformer inoperable for the performance of voluntary, planned maintenance activities. This 30 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 16. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the offsite circuits to ensure that the offsite circuit is capable of fulfilling its intended functions. If the performance or condition of the offsite circuit does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 A.3 would result in unacceptable unavailability of the offsite circuit, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 30 day Completion Time.

Administrative controls applied during any extended offsite circuit (Startup Transformer) outage time for voluntary planned maintenance activities ensure or require that:

b. Switchyard Activity - During this maintenance on the Startup Transformer, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

   In accordance with the CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Emergeny Diesel Generators (DGs), Startup Transformers, 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the Startup Transformer maintenance outage.

c. Scheduling to Minimize Grid Loading and Weather Related Impacts - The prospective schedule window for the proposed Startup Transformer outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus, times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window. The schedule also anticipates suitable weather conditions conductive to the performance of the mostly outdoor transformer maintenance tasks. These considerations include equipment protection, minimized job interruptions, and good worker conditions.

BASES

ACTIONS (continued)

B.4

Insert B

~~According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.~~

~~In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour 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 second Completion Time for Required Action B.4 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 B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. 30 days This could lead to a total of 144 hours, 40 days since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) 70 allowed prior to complete restoration of the LCO. The 6 day 40 Completion Time provides a limit on 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 72 hour 10 days and 6 day 40 Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for

(continued)

Insert B (page B 3.8-10)

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.

This Completion Time (CT) is intended to be used for repair and preventive maintenance activities. With regard to repair, historically, at Comanche Peak the average duration of repair activities is significantly less than the CT of 10 days, though there may be more than one such entry per year. The foregoing does not imply that, if necessary, Comanche Peak will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. A completion time approaching 10 days also allows for declaring or rendering a DG inoperable for the performance of voluntary, planned maintenance activities. This 10 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 16. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the DG to ensure that the DG is capable of fulfilling its intended functions. If the performance or condition of the DG does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 B.4 would result in unacceptable unavailability of the DGs, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 10 day Completion Time.

Administrative controls applied during any extended DG outage time for voluntary planned maintenance activities ensure or require that:

a. Switchyard Activity - During this maintenance on the DG, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

   In accordance with the CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Startup Transformers, 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, the opposite train Diesel Generator (DG), Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the planned DG maintenance outage.

c. Scheduling to Minimize Grid Loading and Weather Related Impacts - The prospective schedule window for the proposed DG outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus, times of peak tornado, and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window.

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9 Rev 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, January 1978.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308-1974.
13. IEEE Standard 387-1977
14. Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," May 31, 1994.
15. ANSI C84.1

INSERT C

Insert C (page B 3.8-29)

16. License Amendment Request (LAR) 03-07, Revision to Technical Specifications, Extension of Completion Times For Diesel Generators, Qualified Offsite Circuits, and AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

BASES

LCO (continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, and load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via inverted DC voltage or the alternate bypass power supply via Class 1E transformers. 7

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 8 hours.

72

(continued)

Insert D

BASES

ACTIONS

A.1 (continued)

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 72 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 74 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely. 80

(continued)

Insert D (page B 3.8-79)

This 72 hour Completion Time is a risk-informed Completion Time based on a plant-specific analysis using the methodology in Reference 4 and would be used for unplanned repair activities. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) to ensure that the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) is capable of fulfilling its intended functions. If the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.9 A.1 would result in unacceptable unavailability of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus), which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement.

FOR INFORMATION ONLY

BASES

ACTIONS (continued)

B.1

With one AC vital bus inoperable the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, or alternate bypass power via Class 1E transformers. 16

Condition B represents one AC vital bus without non-interruptible inverted DC power. In this situation, the unit is significantly more vulnerable to a complete loss of all non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of non-interruptible power to the remaining vital buses and restoring power to the affected vital bus subsystems. 16

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an
72 AC bus is inoperable and subsequently returned OPERABLE, the LCO
may already have been not met for up to 8 hours. This could lead to a 32
74 total of 10 hours, since initial failure of the LCO, to restore the vital bus
distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

80

C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

FOR INFORMATION ONLY

BASES

ACTIONS

C.1 (continued)

Condition C represents one or more electrical power distribution subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning for the affected bus(es). In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining bus(es) and restoring power to the affected bus(es).

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO

(continued)

BASES

ACTIONS

C.1 (continued)

72

74

may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

80

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.

INSERT E

Insert E (page B 3.8-84)

4. License Amendment Request (LAR) 03-07, Revision to Technical Specifications, Extension of Completion Times For Diesel Generators, Qualified Offsite Circuits, and AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

ATTACHMENT 4 to TXX-03137

RETYPED TECHNICAL SPECIFICATION PAGES

Pages	**3.8-2**
	3.8-4
	3.8-38
	3.8-39

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND -------------NOTE-------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ------------------------------------	
	A.2 Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND A.3 Restore required offsite circuit to OPERABLE status.	30 days AND 40 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.4 Restore DG to OPERABLE status.	10 days AND 40 days from discovery of failure to meet LCO
C. Two required offsite circuits inoperable.	----------NOTE---------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ------------------------------ C.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND C.2 Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	72 hours AND 80 hours from discovery of failure to meet LCO
B. One AC vital bus subsystem inoperable.	B.1	Restore AC vital bus subsystem to OPERABLE status.	2 hours AND 80 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 80 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

ATTACHMENT 5 to TXX-03137

RETYPED TECHNICAL SPECIFICATION BASES PAGES
(For Information Only)

Pages	**B 3.8-7**
	B 3.8-7a
	B 3.8-10
	B 3.8-10a
	B 3.8-29
	B 3.8-78
	B 3.8-79
	B 3.8-81
	B 3.8-83
	B 3.8-84

BASES

ACTIONS (continued)

A.3

In Condition A, the remaining offsite circuit is 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.

This Completion Time (CT) is intended to be used for repair and preventive maintenance activities. With regard to repair, historically, at Comanche Peak the average duration of repair activities is significantly less than the CT of 30 days, though there may be more than one such entry per year. The foregoing does not imply that, if necessary, Comanche Peak will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. A completion time approaching 30 days also allows for declaring or rendering a startup transformer inoperable for the performance of voluntary, planned maintenance activities. This 30 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 16. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the offsite circuits to ensure that the offsite circuit is capable of fulfilling its intended functions. If the performance or condition of the offsite circuit does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 A.3 would result in unacceptable unavailability of the offsite circuit, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 30 day Completion Time.

Administrative controls applied during any extended offsite circuit (Startup Transformer) outage time for voluntary planned maintenance activities ensure or require that:

a. Switchyard Activity – During this maintenance on the Startup Transformer, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures require management approval for entry into an LCO for planned maintenance activities

(continued)

BASES

ACTIONS

A.3 (continued)

that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

In accordance with CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Diesel Generators (DGs), Startup Transformers, 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the Startup Transformer maintenance outage.

c. Scheduling to Minimize Grid Loading and Weather Related Impacts – The prospective schedule window for the proposed Startup Transformer outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window. The schedule also anticipates suitable weather conditions conducive to the performance of the mostly outdoor transformer maintenance tasks. These considerations include equipment protection, minimized job interruptions, and good worker conditions.

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 10 days. This could lead to a total of 40 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 10 days (for a total of 50 days) allowed prior to complete restoration of the LCO. The 40 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 days and 40 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.4

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.

This Completion Time (CT) is intended to be used for repair and preventive maintenance activities. With regard to repair, historically, at Comanche Peak the average duration of repair activities is significantly less than the CT of 10 days, though there may be more than one such entry per year. The foregoing does not imply that, if necessary, Comanche Peak will not use the full CT to complete extended repairs, only that it is unlikely that such would occur based on historical plant data. A completion time approaching 10 days also allows for declaring or rendering a DG inoperable for the performance of voluntary, planned maintenance activities. This 10 day Completion Time is a risk-informed outage time based on a plant-specific analysis using the methodology in Reference 4. The Maintenance Rule (10CFR50.65) requires each licensee to monitor the performance or condition of the DG to ensure that the DG is capable of fulfilling its intended functions. If the performance or condition of the DG does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.1 B.4 would result in unacceptable unavailability of the DGs, which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The controls of the Configuration Risk Management Program (CRMP) and the Maintenance Rule would preclude misuse of the 14 day Completion Time.

Administrative controls applied during any extended DG outage time for voluntary planned maintenance activities ensure or require that:

a. Switchyard Activity – During this maintenance on the DG, all activity in the switchyards will be closely monitored and controlled. Switchyard postings and heightened control will be implemented. No activity will be allowed that could challenge the operability of any offsite AC power source.

b. The Configuration Risk Management Program (CRMP) (see TS 5.5.18) will be applied throughout the duration of the extended outage. Additionally plant procedures require management approval for entry into an LCO for planned maintenance activities that would exceed 50% of the required LCO Completion Time. Management approval results in an overall heightened plant awareness in support of the planned activity.

(continued)

BASES

ACTIONS

B.4 (continued)

In accordance with CRMP, equipment identified as important to Loss of Offsite Power and Station Blackout considerations will be administratively controlled and protected to ensure that the equipment, including the Startup Transformers 6.9 kV AC safety buses, Turbine Driven Auxiliary Feedwater (TDAFW) Systems, the opposite train Diesel Generator, Station Service Water (SSW) Systems, and Blackout Sequencers, assuming both units are at power, remain operable and available for the duration of the Startup Transformer maintenance outage.

c. *Scheduling to Minimize Grid Loading and Weather Related Impacts* – The prospective schedule window for the proposed DG outage will be implemented during the time of the year when the weather at CPSES, historically, has not been severe and threatening to off-site power. Thus, times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak will be considered in identifying the schedule window.

The second Completion Time for Required Action B.4 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 B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 30 days. This could lead to a total of 40 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 30 days (for a total of 70 days) allowed prior to complete restoration of the LCO. The 40 day Completion Time provides a limit on 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 10 days and 40 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9 Rev 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, January 1978.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308-1974.
13. IEEE Standard 387-1977
14. Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," May 31, 1994.
15. ANSI C84.1
16. License Amendment Request (LAR) 03-07, Revision to Technical Specifications, Extension of Completions Times For Diesel Generators, Qualified Offsite Circuits, and AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

BASES

LCO (continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, and load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via inverted DC voltage or the alternate bypass power supply via Class 1E transformers.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 72 hours.

(continued)

BASES

ACTIONS

A.1 (continued)

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. This 72 hour Completion Time (CT) based on a plant-specific analysis using the methodology in Reference 4 and would be used for unplanned repair activities. Also the Maintenance Rule (10CR50.65) requires each licensee to monitor the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) to ensure that the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) is capable of fulfilling its intended functions. If the performance or condition of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) does not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Multiple entries into Technical Specification Required Action 3.8.9 A.1 would result in unacceptable unavailability of the AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus), which in the long term would negatively affect the performance indicators in the Reactor Oversight Process (ROP) Performance Indicator Program. The ROP focuses on the licensee's ability to (1) limit the frequency of initiating events and (2) ensure the availability, reliability, and capability of mitigating systems. This feedback loop forces the licensee to manage the number and length of entries into an Action Statement. The 72 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

BASES

ACTIONS

C.1 (continued)

may already have been not met for up to 72 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

(continued)

BASES (continued)

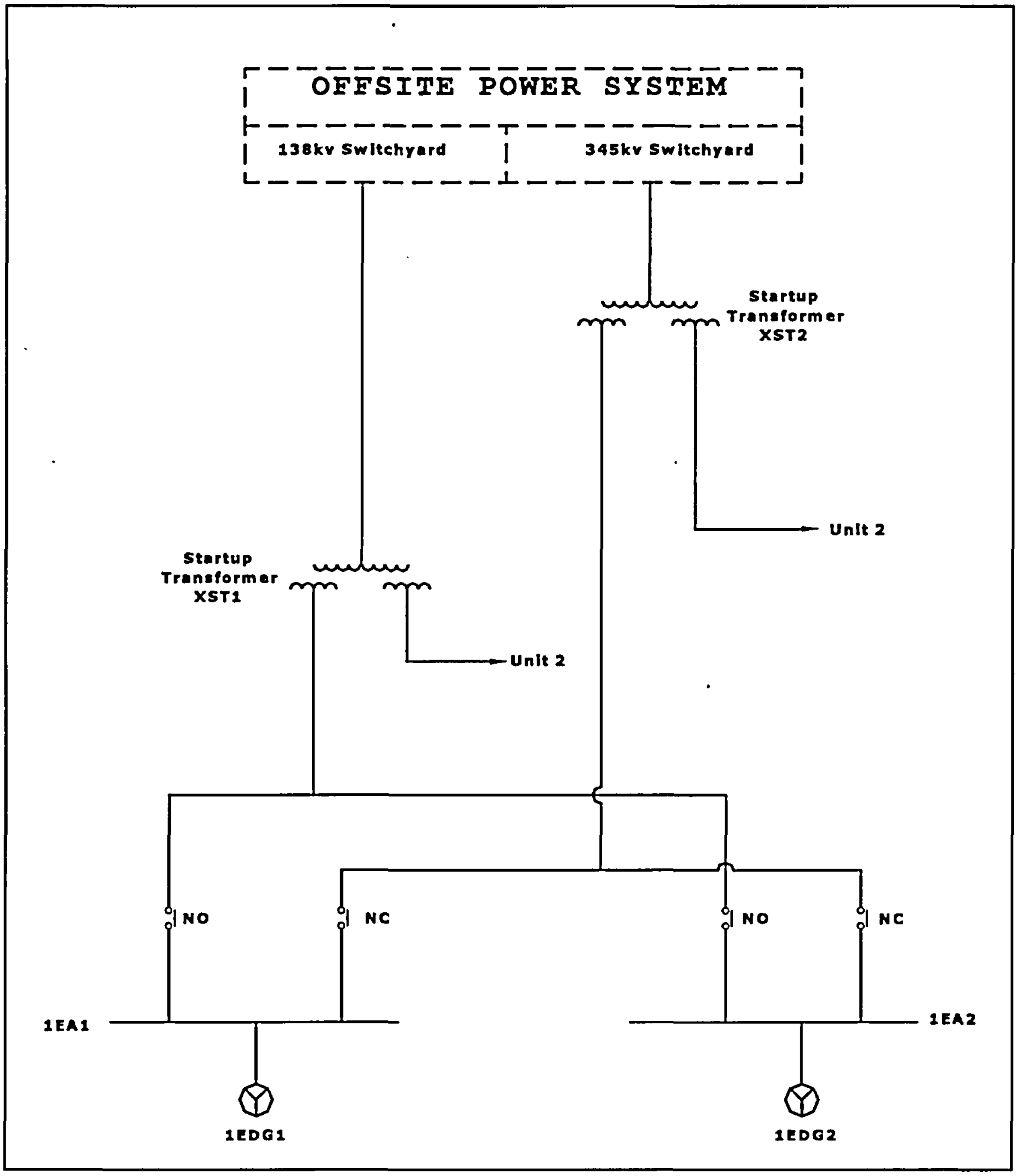
SURVEILLANCE REQUIREMENTS

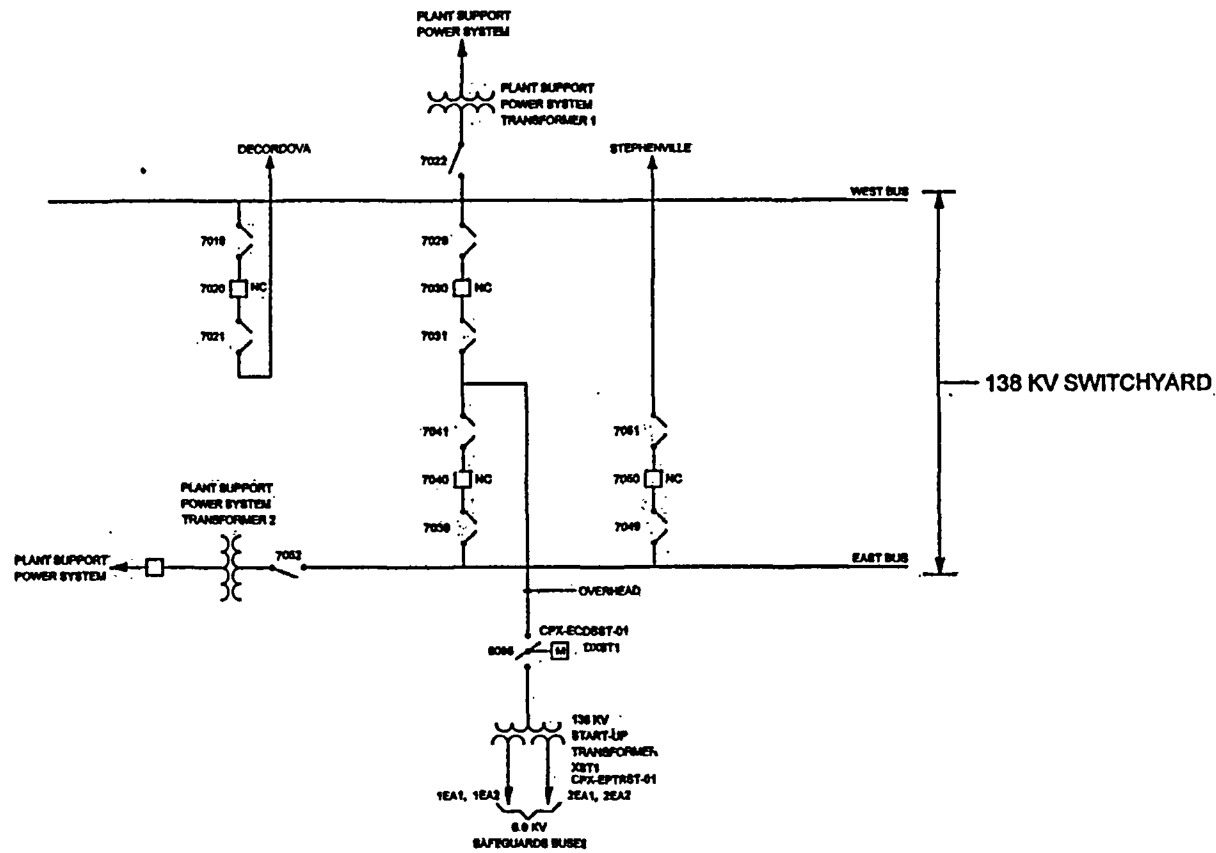
SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

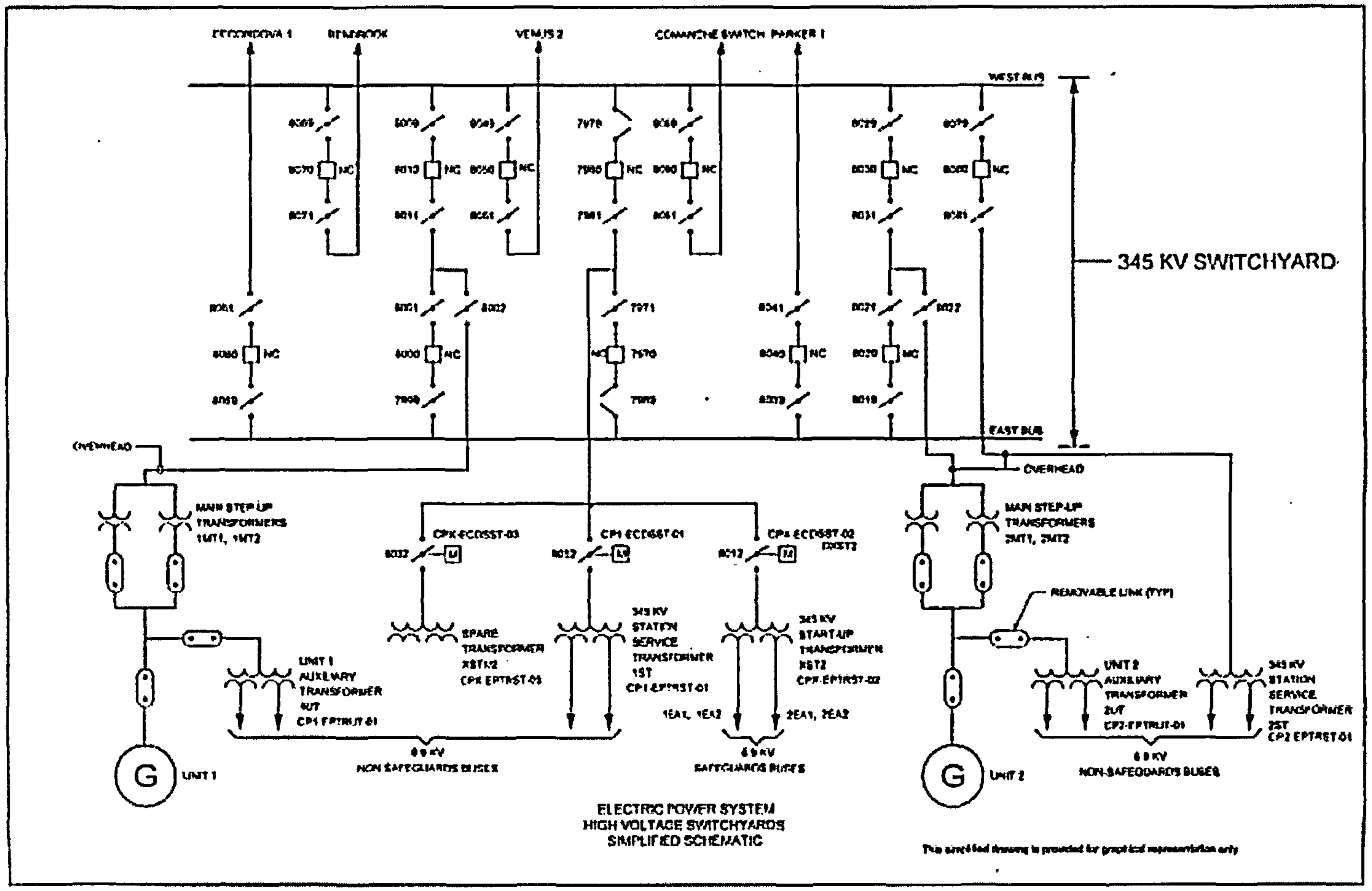
1. FSAR, Chapter 6.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.
4. License Amendment Request (LAR) 03-07, Revision to Technical Specifications, Extension of Completion Times For Diesel Generators, Qualified Offsite Circuits, and AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.


OFFSITE POWER SYSTEM
138kv Switchyard
345kv Switchyard
Startup
Transformer
XST2
Unit 2
Startup
Transformer
XST1
Unit 2
NO
NC
NO
NC
1EA1
1EA2
1EDG1
1EDG2



ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC

This simplified drawing is provided for graphical representation only.


VENUS 2
COMANCHE SWITCH
PARKER 1
WEST BUS
EAST BUS
345 KV SWITCHYARD
OVERHEAD
MAIN STEP-UP TRANSFORMERS 1MT1, 1MT2
MAIN STEP-UP TRANSFORMERS 2MT1, 2MT2
REMOVABLE LINK (TYP)
SPARE TRANSFORMER
345 KV STATION SERVICE TRANSFORMER 1ST
345 KV START-UP TRANSFORMER XST2
UNIT 1 AUXILIARY TRANSFORMER 1UT
UNIT 2 AUXILIARY TRANSFORMER 2UT
345 KV STATION SERVICE TRANSFORMER 2ST
6.9 KV NON SAFEGUARDS BUSES
6.9 KV SAFEGUARDS BUSES
6.9 KV NON-SAFEGUARDS BUSES
1EA1, 1EA2
2EA1, 2EA2
G
UNIT 1
G
UNIT 2
ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC