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Ref: 10CFR50.90

CPSES-200601634
Log # TXX-06141
File # 00236

October 13, 2006

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) 06-009
REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1, "AC SOURCES – OPERATING," EXTENSION OF COMPLETION TIMES FOR DIESEL GENERATORS

Dear Sir or Madam:

Pursuant to 10CFR50.90, TXU Generation Company LP (TXU Power) 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 changes into the CPSES Unit 1 and 2 Technical Specifications (TS). This change request applies to both units.

The proposed changes will revise Technical Specification 3.8.1 for "AC Sources – Operating" that will extend the allowable Completion Time (CT) associated with restoration of an inoperable Diesel Generator (DG). The extended CT establishes a 14 day allowable out of service time when one DG is inoperable if an alternate AC power source (AACPS) is available. The 14 day CT extension includes the normal 72 hour CT which is not risk informed, followed by an 11 day extension period based on a plant specific risk analysis performed to establish the overall out of service time. As a defense-in-depth measure, when the option of an extended allowable out of service time for a DG is exercised, an AACPS will be provided with the capability of supplying the same loads as the existing DG. In the absence of an AACPS, the DG 72 hour CT will be applied.

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TXU Power'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 allow performance of periodic DG overhauls on-line and improve DG availability during shutdown.

The justification for these changes to the DG Completion Time is based upon a risk-informed, deterministic evaluation consisting of three main elements: (1) the reliability and 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)), and (3) continued implementation of a Configuration Risk Management Program (CRMP) while the DG is in an extended Completion Time. These elements provide the basis for the requested TS changes 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 Time.

Attachment 1 provides a detailed description of the proposed changes, a technical analysis of the proposed changes, TXU Power'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 (TS) 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 Power requests approval of the proposed License Amendment by October 13, 2007, to be implemented within 120 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 Power 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 Ms. Tamera J. Ervin at (254) 897-6902.

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

Executed on October 13, 2006.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC
Its General Partner

Mike Blevins

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

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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
M. C. Thadani, NRR
Resident Inspectors, CPSES

Ms. Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
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ATTACHMENT 1 to TXX-06141

DESCRIPTION AND ASSESSMENT

LICENSEE'S EVALUATION

1.0 DESCRIPTION

By this letter, TXU Generation Company LP (TXU Power) 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 (TS).

The proposed changes will revise Technical Specification 3.8.1 for "AC Sources – Operating" by adding an alternate Required Action to B.4 that will extend the allowable Completion Time (CT) associated with restoration of an inoperable Diesel Generator (DG). The extended CT establishes a 14 day allowable out of service time when one DG is inoperable if an alternate AC power source (AACPS) is available. The 14 day CT extension includes the normal 72 hour CT which is not risk informed, followed by an 11 day extension period based on a plant specific risk analysis performed to establish the overall out of service time. As a defense-in-depth measure, when the option of an extended allowable out of service time for a DG is exercised, an AACPS will be provided with the capability of supplying the same loads as the existing DG. Additionally, the AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a loss of offsite power (LOOP). Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable. In the absence of an AACPS, the DG 72 hour CT will be applied. The license amendment request also proposes to add a second CT for this alternate Required Action to establish a limit on the maximum time allowed for any combination of required AC electrical sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition for Operation (LCO).

Additionally, an alternate Required Action will be added to Condition A.3. The CT to restore an inoperable required offsite circuit to OPERABLE status will be 72 hours. Furthermore, the second CT for the alternate Required Action establishes a limit on the maximum time allowed for one required offsite circuit and one DG to be inoperable during any single contiguous failure to meet the LCO if an AACPS is available. In the absence of an AACPS, the DG 72 hour CT will be applied.

The requested changes are based upon CPSES plant specific risk-informed and deterministic evaluations performed in a manner consistent with the risk-informed approaches endorsed by Regulatory Guides 1.174 (Reference 8.1) and 1.177 (Reference 8.2). The proposed changes would increase operational flexibility and provide additional allowances for performance of testing, repairs, and periodic maintenance while at power.

2.0 PROPOSED CHANGE

On page 3.8-2 of Technical Specifications (TS) 3.8.1 "AC Sources – Operating," the Required Action A.3 will be renumbered to read A.3.1. The alternate proposed Required Action will be numbered A.3.2 and read, "Restore required offsite circuit to OPERABLE status" and the proposed associated CT will read, "72 hours AND 17 days from discovery of failure to meet LCO due to an inoperable DG with AACPS available." The acronym AACPS is defined as "alternate AC power source." The Required Actions A.3.1 and A.3.2 are choices, only one of which must be performed as indicated by the use of the logical connector "OR" and the left justified placement.

On Page 3.8-4 of TS 3.8.1, the Required Action B.4 will be renumbered to read B.4.1. Additionally, in the CT of this Required Action the word "discover" will have a "y" added to the end of the word to read "discovery." The alternate proposed Required Action will be numbered B.4.2 and will read, "Restore DG to OPERABLE status" and the proposed associated CT will read, "14 days AND 17 days from discovery of failure to meet LCO." The proposed Required Action B.4.1 and B.4.2 are choices, only one of which must be performed as indicated by the use of the logical connector "OR" and the left justified placement.

Required Action B.4.2 will be modified by a note that will read, "Required Action B.4.2 and associated Completion Times are only allowed if an AACPS is available."

For information only, this LAR includes markups in Attachment 3 indicating proposed associated changes to the Bases for TS 3.8.1, "AC Sources – Operating." Retyped TS pages and TS Bases pages which incorporate the proposed changes are provided in Attachments 4 and 5, respectively.

In summary, the proposed changes will revise TS 3.8.1 for "AC Sources – Operating" to add an alternate Required Action to B.4 that will extend the CT for an inoperable DG if an AACPS is available. Additionally, the proposed changes for TS 3.8.1 will also add an alternate Required Action to A.3 for one required offsite circuit inoperable, that will extend the second CT due to an inoperable DG if an AACPS is available.

3.0 BACKGROUND

The allowable alternate Required Actions Completion Time (CT) extension for the diesel generator (DG) is expected to be used for performing maintenance activities on-line if an alternate AC power source AACPS is available. Conversely, in the absence of an AACPS, the DG 72 hour CT will be applied. The proposed changes would increase operational flexibility and provide additional allowances for performance of testing, repairs, and periodic maintenance while at power. Section 4 includes a detailed description and background of the reliability and availability of the onsite and the offsite power system, Station Blackout DG capacity, onsite power design criteria, and other considerations for Comanche Peak Steam Electric Station (CPSES).

The current CT 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. United States Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974, (Reference 8.4) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., CT and maintenance limitations) that the NRC considers acceptable if the number of available AC power sources is less than the LCO. This change deviates from RG 1.93 as described in Section 5.

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 United States Nuclear Regulatory Commission (NRC) Safety Goal Policy Statement (Reference 8.12), and the acceptance criteria in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998, (Reference 8.1) and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998 (Reference 8.2) are met. As an additional defense-in-depth measure, when the option of an extended allowable out of service time for a DG is exercised, an alternate AC power source (AACPS) will be provided with the capability of supplying the same loads as the existing DG. Additionally, the AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a LOOP. Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable. Conversely, in the absence of an AACPS, the DG 72 hour Completion Time (CT) will be applied.

The justification for these changes to the DG CT is based upon a risk-informed, deterministic evaluation consisting of three main elements: (1) the reliability and 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)), and (3) continued implementation of a Configuration Risk Management Program (CRMP) while the DG is in an extended CT. These elements provide the basis for the requested Technical Specifications (TS) changes 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 CT.

4.1 Traditional Engineering Considerations

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.

Comanche Peak Steam Electric Station (CPSES) is designed and operated consistent with the defense-in-depth philosophy. The units have diverse power sources available (e.g., DGs and startup transformers (STs)) to cope with a loss of the preferred alternating current (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 CT and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems when an AACPS is available.

While the proposed changes do increase the length of time a DG can be out of service during unit operation, it will increase the availability of the DGs while the unit is shutdown. The increased availability of the DG while a unit is shutdown will increase the defense-in-depth of systems 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 Probabilistic Risk Assessment (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.

Onsite and offsite system redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to these systems. 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 administrative controls to ensure adequate defense-in-depth whenever a DG is out of service. Furthermore, 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 will be maintained. These proposed changes require no new operator response. The operator actions required to start and load the AACPS manually are the same as the response to a DG failure to start. The difference is that this change will involve the use of an AACPS. Station procedures will be revised as necessary and appropriate training will be provided to ensure adequate defense against human errors are maintained. These operator actions have been accounted for in the PRA model. The results of the analysis for adding the alternate Required Action CT for the DG included these operator actions. 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 as a result of performing DG maintenance on-line.

"Conformance with NRC General Design Criteria (GDC)," Section 3.1 of the Final Safety Analysis Report (FSAR) (Reference 8.3) provides the basis for concluding that the station fully satisfies and complies with the 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 the GDC.

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

- **Reliability and Availability of the Offsite Power System**

  The transmission lines of TXU Electric Delivery (ED) (also known as CPSES' Transmission and or Distribution Service Provider (TDSP)) comprise an integrated system with operations coordinated by the System Dispatcher so as to maintain system reliability. Transmission systems consist of 345 kilovolts (kV) lines for bulk supply and 138 kV and 69 kV lines to transmit power to load-serving substations. Composition of generation sources connected to ED's transmission system includes 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. Startup and shutdown power for the units is derived from the 138 kV and 345 kV systems. 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 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 via startup transformer XST2; the preferred source to Unit 2 is the 138 kV offsite supply from the 138 kV switchyard via startup transformer XST1. Each of the startup transformers (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses as a preferred source; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses.

The preferred power sources supply power to the Class 1E buses during plant startup, normal operation, emergency shutdown, and upon a unit trip. This eliminates the need for automatic transfer of safety-related loads in the event of a unit trip.

Each startup transformer has the capacity to supply the required Class 1E loads of both units during all modes of plant operation. In the event one startup transformer (e.g., XST1, a preferred source) becomes unavailable to its Class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme. For the loss of a startup transformer, the load transfer only takes place in the unit for which the transformer was the preferred source. If it becomes necessary to safely shut down both units simultaneously, 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 although the design criteria require consideration of a Design Basis Accident on one unit only.

- **Reliability and Availability of the Onsite Standby 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 the preferred and the alternate offsite 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 provided with standby power from a dedicated DG. Each DG is directly connected to its dedicated bus. 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.

A DG is automatically started by a safety injection signal or an under-voltage condition 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 and close its output breaker. Sequential loading of the DG is automatically performed as a result of sequential loading of its dedicated bus.

The DG output breaker will close to its dedicated 6.9 kV Class 1E bus automatically only if the other source feeder breakers to the bus are open. When the DG output breaker is closed, no other source feeder breaker will close automatically. Design and procedural controls ensure that no means exist for connecting redundant buses with each other.

The design basis for the DGs is that the loss of one DG will not result in the inability to perform a 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.

- **Station Blackout (SBO) DG Capacity**

CPSES is able to withstand and recover from a SBO event of 4 hours duration in accordance with the guidelines of RG 1.155, "Station Blackout," dated August 1988 (Reference 8.5). The 4-hour coping duration was determined by approved methods based on the redundancy and reliability of onsite emergency AC power sources, the expected frequency of loss of offsite power, and the probable time needed to restore offsite power.

Assumptions relevant to the proposed changes and used in the SBO analysis include:

1. One Unit at the CPSES site is assumed to be in a station blackout condition. The other unit is assumed to have one emergency DG available.
2. One emergency DG is capable of powering one train of those safety-related systems which are common to both Units 1 and 2.
3. Per NUMARC 87-00 (Reference 8.26), NRC Staff analysis reports the median AC power restoration time for all LOOP events to be about 1/2 hour, with offsite power restored in approximately 3 hours for 90 percent of all events.
4. As stated in NUMARC 87-00, since a number of failures must occur to result in a station blackout event, additional independent failures are of secondary importance.
5. Following the loss of all AC power, the reactor will shutdown automatically since the control rod drive mechanism rod drive motor generator sets will lose power.

The proposed changes are bounded by these assumptions. Therefore, the assumptions used in the SBO analysis regarding the availability and reliability of the emergency DGs are unaffected by this proposed change. The results of the SBO analysis are also unaffected by this proposed change.

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

- **Onsite Power System Design Criteria**

Compliance with NRC design criteria is described in detail in FSAR Section 8.1, "INTRODUCTION," and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES." 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 8.6) as discussed in Appendix 1A(B) of the FSAR 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 8.7) 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 8.8) is described in detail in Appendix 1A(B) to the FSAR.

CPSES conformance with Regulatory Guide 1.93, Revision 0, dated December 1974, titled "Availability of Electric Power Sources," (Reference 8.4) is described in Appendix 1A(B) to the FSAR. The station currently conforms to Regulatory Guide 1.93, specifically the 72-hour CT and the proviso that the operating time limits are explicitly for corrective maintenance activities only. If the proposed changes are approved, the station will continue to conform to RG 1.93 with the exceptions that the CT for Required Actions associated with the restoration of a DG will be 14 days and the CT may be used for all DG maintenance if an AACPS is available. CPSES will adhere to a 72 hour CT in the absence of an AACPS.

CPSES commitments to conformance with other key design criteria applicable to onsite electrical systems are 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 8.9); Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions," (Reference 8.10); and Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 8.11).

Other Considerations

As discussed above and in Section 5.2, CPSES conformance with relevant regulatory guidance is not affected by these proposed changes, with the exception of RG 1.93.

DG operability following repair or maintenance activities will continue to be based on surveillance test(s) recommended by RGs 1.9 and 1.137. The surveillance tests to be performed to ensure DG operability are dependent on the scope of the maintenance activities performed. For normal maintenance, 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 repair or replacement, the full load reject and manual load sequencing at power would be required.

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 offsite sources of power. The proposed changes do not affect any assumptions or inputs to the safety analyses. All safety functions continue to be available and all safety analysis acceptance criteria continue to be met.

Application of the Configuration Risk Management Program

Methodologies (Configuration Risk Management Program (CRMP)) associated with risk monitoring and contingency action planning currently exist at CPSES and provide an acceptable risk profile during periods of equipment inoperability. Plant procedures require management approval for entry into a limiting condition for operation (LCO) for planned maintenance activities that would exceed 50% of the required LCO CT. Thus if the planned DG maintenance activity requires greater than 50% of the requested CT, existing plant procedures would ensure specific management attention and heightened plant awareness in support of the planned activity.

Operator, maintenance, and management focus will be maximized by scheduling performance of 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 DG 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.

Station procedure STA-604, "Configuration Risk Management and Work Scheduling" implements the requirements of TS 5.5.18, "Configuration Risk Management Program (CRMP)." Procedure STA-604, along with other station procedures, provides the administrative controls to ensure that equipment important to accident mitigation remains operable and available for the duration of a planned DG maintenance outage. For example, to minimize risk during a planned maintenance outage of a DG, maintenance and testing of the other unit DG, the station transformers (XST1 or XST2), or the unit 6.9 kV AC safety buses would not be conducted.

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 relied upon for mitigation of station blackout conditions when the electric motor-driven auxiliary feedwater pumps would be unavailable. Surveillance testing of any such "protected" equipment that might become due during the period that the DG is out of service would be performed prior to removing the DG from service. Limiting testing in this way protects the availability of equipment during the DG maintenance window. This does not imply that surveillance testing requirements will not be performed on key equipment as required, but only that surveillance testing will be shifted as allowed by TS (e.g., within 1.25 times the interval specified in the Frequency).

Routine testing and preventive maintenance activities are normally scheduled to be performed on a 12 week rotating basis. Work schedules can be adjusted to ensure that surveillance testing of equipment, identified as important to LOOP and SBO considerations, is demonstrated current prior to the start of the DG outage work window and will not be required on the equipment for the duration of the planned DG outage.

Risk management strategies and maintenance practices at CPSES ensure that extensive work planning is performed. Important aspects of this planning not already mentioned include pre-job briefs and consideration of overall station operating configuration which includes opposite unit impact.

When scheduling, to minimize grid loading and weather related impacts, the prospective schedule window for any proposed on-line DG outage will be implemented during the time of the year when weather conditions at CPSES have historically not been severe or threatening to offsite power. 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 electric demands will be considered in selecting the on-line DG maintenance window. Other weather-related considerations include equipment protection, minimal job interruptions, and good worker conditions. Therefore, the 14 day CT extension will not be exercised if weather conditions are not conducive to performance of on-line DG maintenance.

Station procedure STA-629, "Switchyard Control," is part of the Generation Interconnect Agreement for CPSES and defines responsibilities for the design, maintenance, control, and operation of the CPSES switchyards. STA-629 establishes the necessary interfaces between CPSES and the transmission grid system operators. This procedure also provides guidance for the timely exchange of necessary and pertinent information. This guidance has been summarized and is added to the procedure in the form of Attachments 8.F, "Communication Protocol," Attachment 8.G, "CPSES – Plant Condition Communication Guideline," and is also supported by Attachment 8.H, "CPSES Offsite Power System Performance Characteristics," and Attachment 8.I, "CPSES Generator and Transformer Performance Characteristics." STA-629 ensures (1) activities in the switchyards are closely monitored and controlled, (2) all switchyard maintenance is reviewed to ensure that the increase in probability of loss of offsite power is minimized, and (3) switchyard access is strictly controlled to minimize the potential for offsite power transients. Therefore, the DG 14 day CT will not be exercised if switchyard and grid conditions are not conducive to perform on-line maintenance of the DG.

In summary, CPSES has a robust design which retains desired design features such as defense-in-depth (i.e., the ability to mitigate design basis accidents when the DG is out of service). The risk-informed CT will be implemented consistent with the CRMP and STA-629. When utilizing the 14 day CT, the requirements of the CRMP per TS 5.5.18 call for the consideration of other measures to mitigate consequences of an accident occurring while a DG is inoperable. Furthermore, the provisions of STA-629 will be applied when exercising the 14 day DG CT extension and are sufficient to maintain adequate defense-in-depth and existing safety margins.

Diesel Generator Completion Time (Technical Specification Bases 3.8.1)

The Completion Time for Required Action B.4.2 establishes a 14 day allowable out of service time when one DG is inoperable and an AACPS is available. The 14 day Completion Time includes the normal 72 hour allowable out of service time which is not risk informed, followed by an 11 day extension period based on a plant specific risk analysis performed to establish the overall out of service time.

With one DG out of service, the remaining OPERABLE unit DG, the offsite circuits, and the alternate AC power source (AACPS) are adequate to supply electrical power to the unit onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources and the AACPS, a reasonable time for maintenance, and the low probability of a DBA occurring during this period.

As a defense-in-depth measure, when the option of an extended allowable out of service time for an emergency DG is exercised, an AACPS will be provided with capability of supplying the same loads as the existing DGs. Thus the AACPS will be capable of supplying safe shutdown loads during a station blackout. For unplanned DG outages, an AACPS will be available upon entering the allowed outage period extension (i.e., by 72 hours into the 14 day Completion Time). For DG outages planned to exceed an initial 72 hours Completion Time, an AACPS will be provided within one hour of entering the Condition B 14 day Completion Time. In any event, if an AACPS of the required capacity is not available after entering the extended Completion Time period (after 72 hours into the Completion Time), the requirement to be in at least Hot Standby within the next 6 hours and in Cold Shutdown within the following 36 hours would apply.

The following criteria would apply to any AACPS used as a defense-in-depth measure:

1. An AACPS may be of a temporary or permanent nature and would not be required to satisfy Class 1E requirements.

2. The dynamic effects of an AACPS failure (GDC 4 events) would not adversely affect safety related plant equipment.

3. An AACPS would not be required to be protected against natural phenomena (GDC 2 events) or abnormal environmental or dynamic effects (GDC 4 events).

4. An AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a LOOP. Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable.

Prior to relying on its availability, a temporary AACPS would be determined to be available by: (1) starting the AACPS and verifying proper operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to the required safe shutdown loads. Subsequently, when not in operation, a status check for availability will also be performed once every 72 hours. This check will consist of (1) verifying the AACPS is mechanically and electrically ready for operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to the required safe shutdown loads.

Prior to relying on its availability, a permanent AACPS would be determined to be available by starting the AACPS and verifying proper operation. In addition, initial and periodic testing, surveillances, and maintenance will conform to NUMARC 87-00, Revision 1, Appendix B, "Alternate AC Power Criteria" guidelines. Functional testing, timed starts, and load capacity testing on a fuel cycle basis, and surveillance and maintenance will consider manufacturer's recommendations.

The following administrative controls will be applicable when utilizing the 14 day CT for DG on-line DG maintenance activities:

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

2. Weather conditions must be historically conducive to perform maintenance on the DG.

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

4. Switchyard access will be monitored and controlled.

The second Completion Time for Required Action B.4.2 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 offsite circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 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 20 days) allowed prior to complete restoration of the LCO. The second Completion Time of 17 days provides a limit on the time allowed to restore the LCO after discovery of a 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 14 day and 17 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 17-day second CT 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.

4.2 Evaluation of Risk Impact

The requested CT extension for the DG is expected to be used to support maintenance activities as discussed in Section 4.1. The probabilistic evaluations presented in the following sections support and justify the allowed CT extension request for the DG. The risk analysis methods employed are described 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 RGs 1.174 and 1.177 (References 8.1and 8.2, respectively).

Description of the CPSES PRA Model

The CPSES PRA model for internal events is an all-MODES model that allows quantification of configurations to determine core damage frequency and large early release frequency at power (MODE 1), in transition (MODES 2 through 4) and while shutdown (MODES 5 and 6). The CPSES PRA model for internal events also includes spent fuel pool modeling for core-off load configurations; however, only MODE 1 was considered in the evaluation of extending the CT for the DG from 72 hours to 14 days.

Data Review and Model Evaluation

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 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 extending the DG CT evaluation is listed below.

- CPSES Full Power PRA analysis files and computer model.
- Reactor Coolant Pump (RCP) Seal loss of coolant accident (LOCA) model.

- DG common cause failure modeling data and techniques.
- LOOP Initiating Event Frequency and post-initiator plant response.
- SBO 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).

The scope of the existing PRA was reviewed to ensure that it is adequate to evaluate the impact of the proposed CT extension. 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 LOOP and SBO models were reviewed. For the requested DG CT extension, 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 of the RCP Seal LOCA model to ensure integrity and completeness.

The review of the PRA model to ensure high quality standards is required for all risk-informed submittals under RG 1.174 (Reference 8.1). 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 Power reviewed the DG reliability data, the LOOP and SBO sequences, and the RCP Seal LOCA model using the Westinghouse Owners Group (WOG) certification guidelines (Reference 8.13). 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 LOOP and 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 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.

It was confirmed that the existing RCP Seal LOCA model contains all of the failure modes identified in the United States Nuclear Regulatory Commission (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 a small increase in the baseline risk. These results show that the CPSES PRA model compares very favorably with the USNRC-approved Brookhaven RCP Seal LOCA model. Thus, the conclusions of this study remain unchanged and the proposed CT extensions are supported.

The PRA model has been updated since the individual plant examination (IPE) and a number of areas have been strengthened. The human reliability analysis (HRA) values were reviewed and recalculated when applicable. The common cause values were recalculated using the common cause tool developed by Data Systems & Solutions (DS&S). Plant specific data has been used to update the generic failure probabilities values used in the PRA model using Bayesian techniques. The PRA model was updated to include separate branches for the components of loss of offsite power (plant-centered, weather-centered, and grid-centered).

PRA Model Modifications

Several modifications to the CPSES PRA model were made for this evaluation. As a surrogate for an AACPS, a DG capable of supplying all the emergency loads for one train was modeled for failure to start and run along with the failure of the operator to start the AACPS and the failure of the AACPS output breaker to close. Any of these events would prevent the AACPS from supplying power to the safety related bus. No credit was taken for starting and running of the AACPS when a large LOCA or medium LOCA was the initiating event because the time to core damage, due to these types of LOCAs, was not sufficient to allow the manual starting and loading of the AACPS.

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 CT only affects the risk contributions of individual component unavailability, inclusion of floods, fires, and external events would not affect 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 CT would be unaffected.

Analysis Assumptions

The following assumptions were used in performing the analysis.

The Incremental Conditional Core Damage probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) were calculated by assuming the DG is in maintenance with the administrative controls described earlier in place (e.g., no switchyard work resulting in a reduced LOOP frequency) for the entire CT duration. Component outage in the opposite train was not allowed.

The delta CDF and LERF were calculated by assuming the DG is in maintenance with the specified administrative controls in place (e.g., no switchyard work resulting in a reduced LOOP frequency) for the proposed 14-day CT duration and then adding the baseline CDF/LERF for the remainder of the year. The basis for this is that the risk reduction measures (administrative controls) would not be in affect during the remainder of the year. This approach is similar to the approach used in the NRC Inspection Manual Chapter 0609 "Significance Determination Process" (SDP).

The assumption was made that CPSES will not plan maintenance that would lead to the DG being unavailable when work is being performed in the switchyard. Also, CPSES would not plan DG maintenance during the time of the year when the weather at CPSES has historically been severe (i.e., likelihood of tornado or thunderstorms). Therefore, to account for these administrative controls the LOOP frequency was recalculated. A new CDF and LERF were calculated using the new LOOP frequency. This new CDF was then multiplied by the period of time it was in effect (14 days) and combined with the baseline CDF multiplied by the time it was in effect (365 – 14 = 351 days) to determine the DG out of service CDF. This combination of new CDF (reduced LOOP frequency) with baseline CDF (baseline LOOP frequency) allows credit for administrative controls during the 14 day CT, but does not take credit for the administrative controls for the whole year. If credit were taken for administrative controls for the whole year (i.e., using only the reduced LOOP frequency) the calculated risk results would be non-conservative.

The impacts of the proposed CT changes were 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 spent fuel pool since the spent fuel pool cooling system is designed such that it can be powered from either unit.

The recovery of the DG that is out of service for maintenance was not allowed. The recovery of the opposite train DG was allowed. This was accomplished by setting the "Test and Maintenance" basic event instead of "the fail to start" basic event for the applicable DG to "TRUE" in the Flag File.

The PRA modeling assumed that when exercising the 14 day extension, the AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a LOOP. Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable. The failure probability of the AACPS output breaker was assumed to be the same as the emergency DG output breaker.

No credit was taken for the AACPS with large and /or medium break Loss of Coolant Accidents (LOCA) initiators. The required time frame for starting the AACPS to prevent core damage was considered to be too short. Therefore the operator, output breaker, and the AACPS were failed when the initiator was a large or medium LOCA.

The Westinghouse methodology used in WCAP-15622-P (Reference 8.16) 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. TS 3.8.1 requires 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, TS 3.0.3 would require the plant be shutdown. Thus, operating with this condition for extended periods is precluded and therefore has no bearing on the risk impact of the proposed extended CT when compared to the current CT.

This conclusion can be drawn because the common cause failure (CCF) exposure time is dependent only on the DG common mode failure TS action statement; it is independent of the CT. This TS is currently in place and will remain in place with the increased 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 DG out of service times. Accordingly, the average out of service time for a DG is less than 20 hours as compared to the current TS allowed CT of 72 hours. There may be cases where corrective or repair-type maintenance takes longer than the historical times. Historically, at CPSES, the majority of the DG unavailability occurs as a result of corrective or preventive maintenance. The DGs are normally in standby and are only started for surveillance testing or due to an actual emergency. The CT "clock" starts when the DG is made inoperable whether due to removal from service for maintenance or due to an actual component failure. Consequently, this is the justification for not requesting a separate CT for repair or planned maintenance.

Evaluation Criteria

To determine the effect of the proposed CT extension, the guidance in RGs 1.174 and 1.177 (References 8.1 and 8.2, respectively) was used. The following risk metrics were used to evaluate the risk impacts of extending the DG CT.

ΔCDF_{AVE} = The change in the annual average CDF due to any increase in on-line maintenance unavailability of the DG that could result from the increased allowed CT. This risk metric is used to compare against the criteria of RG 1.174 (Reference 8.1) 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 DG that could result from the increased CT extension. This risk metric is used to compare against the criteria of RG 1.174 (Reference 8.1) to determine whether a change in LERF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, $LERF_{base}$.

$ICCDP_{\{DGxY\}}$ = The incremental conditional core damage probability with DG Y for Unit X out of service for a period equal to the proposed new allowed CT. This risk metric is used as suggested in RG 1.177 (Reference 8.2) to determine whether a proposed increase in allowed CT 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 CT. This risk metric is used as suggested in RG 1.177 (Reference 8.2) to determine whether a proposed increase in allowed CT will have an acceptable risk impact.

The change in core damage probability (ΔCDP) and the change in conditional large early release probability (ΔLERP) are computed per the definitions from RG 1.174 (Reference 8.1). In terms of the parameters defined above, the definitions are as follows:

$$\Delta CDF = [(CDF_{tmbase} * B/365) + (CDF_{reducedLOOP} * CT/365)] - CDF_{tmbase}$$

and

$$\Delta LERF = (LERF_{tmbase} * B/365) + (LERF_{reducedLOOP} * CT/365) - LERF_{tmbase}$$

where:

CDF_{tmbase} = CDF (Model of Record, test and maintenance model)

B = 365 – CT

CT = Completion Time

$CDF_{reducedLOOP}$ = CDF with reduced LOOP and DG out of service (no test or maintenance model)

$LERF_{tmbase}$ = LERF (Model of Record, test and maintenance model)

$LERF_{reducedLOOP}$ = LERF with reduced LOOP and DG out of service (no test or maintenance model)

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 8.2). In terms of the parameters defined above, the definitions are as follows:

$$ICCDP = (CDF_{CT} - CDF_{base}) * (CT/365)$$

and

$$ICLERP = (LERF_{CT} - LERF_{base}) * (CT/365)$$

where:

CDF_{CT} = The CDF with the equipment out of service (no test or maintenance model)

CDF_{base} = Baseline CDF (Model of Record, no test or maintenance model)

$LERF_{CT}$ = The LERF with the equipment out of service (no test or maintenance model)

$LERF_{base}$ = Baseline LERF (Model of Record, no test or maintenance model)

CT = Completion Time

Note that in the above formula 365 days/year is merely a conversion factor to make the units for allowed CT 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 CT. This should not be confused with the evaluation of ΔCDF/ΔLERF in which the CDF/LERF is averaged over an 18-month refueling cycle.

Evaluation

The DG CT will continue to be entered for the purpose of routine surveillance testing and other maintenance activities. It is anticipated that the DG CT will also be entered for longer periods 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 calculated ICCDP and ICLERP for the configurations below.

Several cases were evaluated to determine if plant configuration would affect the CT. The Computer Aided Fault Tree Analysis (CAFTA) suite of PRA tools were used for this evaluation. The CAFTA suite of PRA tools is used industry wide and is an accepted suite of software.

The proposed CT evaluated for the DG is 14 days. This evaluation was done using the methodology described below. The equations defined above were used for the evaluation cases described below.

The cases evaluated were:

- Full power model with no equipment in test or maintenance (baseline case)
- DG unavailable with no reduction in plant centered failures (no test or maintenance)
- DG unavailable with reduction in plant centered failures (no test or maintenance)
- DG unavailable with reduction in plant centered failures (with average train B test or maintenance)
- DG unavailable with reduction in plant centered and weather centered failures (no test or maintenance) and with reduction in plant centered failures (no test or maintenance) and the DG failure rate increased to 5.00E-01.

The risk evaluation of performing a 14 day DG maintenance activity at power meets the requirements for a permanent TS change in accordance with RG 1.174 and RG 1.177 (References 8.1 and 8.2, respectively). The requirement of RG 1.174 (Reference 8.1) is a ΔCDF less than 1E-06 and a ΔLERF less than 1E-07. The requirement of RG 1.177 (Reference 8.2) is an ICCDP less than 5E-07 and ICLERP less than 5E-08. The following are the calculated values for the 14 day CT assuming an AACPS is available to supply all the loads of the 1E safety related bus normally powered by the DG which is out of service: ΔCDF of 1.63E-07, ΔLERF of 5.48E-09, ICCDP of 2.77E-07, and ICLERP of 1.01E-08.

Therefore, the request to extend the Completion Time to restore an inoperable DG to OPERABLE status from 72 hours to 14 days when an AACPS is available is supported by this evaluation. The results of all the cases with a DG out of service, including the base cases are shown in Table 1, "Results of Case Studies."

Table 1. Results of Case Studies

Case	Qnt Value	ΔCDF(14d)	ΔLERF(14d)	ICCDP(14d)	ICLERP(14d)
Base CDF (NTM)	6.24E-06				
Base LERF(NTM)	4.95E-07				
Base CDF (TM)	9.20E-06				
Base LERF (TM)	6.16E-07				
DG WITH NRPC NTM CDF	1.35E-05	1.63E-07		2.77E-07	
DG WITH NRPC NTM LERF	7.58E-07		5.48E-09		1.01E-08
DG WITH RPC NTM CDF	1.31E-05	1.48E-07		2.62E-07	
DG WITH RPC NTM LERF	7.47E-07		5.03E-09		9.65E-09
DG WITH RPC, "B" TM CDF	6.62E-05	2.19E-06		2.30E-06	
DG WITH RPC, "B" TM LERF	2.84E-06		8.55E-08		9.01E-08
DG WITH RPC RWC NTM CDF	9.78E-06	2.23E-08		1.36E-07	
DG WITH RPC RWC NTM LERF	6.47E-07		1.20E-09		5.82E-09
DG SENS CDF	5.94E-05	1.93E-06		2.04E-06	

The ΔCDF and ΔLERF calculations used the base case CDF of 9.1603E-06 (test and maintenance included) and LERF of 6.1554E-07.

The ICCDP and ICLERP used the base case CDF of 6.4795E-06 and LERF of 4.9511E-07 (no test or maintenance).

Qnt - Quantification
NTM – No test or maintenance
TM – Test and maintenance
DG – Diesel Generator
NRPC – RPC not reduced
RPC – Reduced value for Plant Centered failures
RWC – Reduced Weather Centered failures
SENS – Sensitivity calculation in which the diesel failure rate was increased to 5.00E-01

4.2.2 Restriction on High Risk Configuration

In addition to the administrative controls proposed by this license amendment, CPSES has existing administrative guidelines to avoid or reduce the potential for risk-significant configurations from either emergent or planned work. These guidelines control configuration risk by assessing the risk impact due to out of service equipment during all modes of operation to ensure that the plant is always operated within acceptable risk guidelines.

CPSES employs a conservative approach to performing maintenance during power operations. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals, and/or administrative controls. 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 re-evaluated. Based on the result of this re-evaluation, decisions are made concerning further actions required to achieve an acceptable level of risk. Unplanned or emergent work activities are also evaluated to determine the impact on other, already planned activities and the affect the combinations would have on risk.

Risk Significant Components While a Diesel Generator is Out of Service

The following components and/or systems become risk-significant when a DG is out of service. The list provides those components and/or systems whose unavailability simultaneous with an out of service DG 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
- Turbine Driven Auxiliary Feedwater Pump and associated piping/valves

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, 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 programmatic controls to ensure as-built plant changes, such as modifications, procedure changes, etc., are routinely evaluated and are accurately reflected in the current model.

The following updates 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 CT for the DG.

- 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.
- 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 Intersystem loss of coolant accident (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 Inservice Testing program (Reference 8.17) and Risk-Informed Inservice Inspection program (Reference 8.18). Additionally, the CPSES PRA supported License Amendment Requests (1) to remove the mode restrictions on several Technical Specification (TS) 3.8.1 surveillance requirements (Reference 8.19), (2) to revise TS 3.8.1 to allow a one-time only change to extend the Action A.3 Completion Time (CT) for restoration of an inoperable offsite circuit from 72 hours to 21 days (Reference 8.20), and (3) to increase the allowed outage time for a centrifugal charging pump from 72 hours to 7 days (Reference 8.21). The NRC has reviewed and approved these risk-informed submittals.

4.4 Summary and Conclusions

The current CT associated with inoperable AC power source(s) is intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. The proposed CT will continue to provide adequate protection of public health and safety and common defense and security as described below. These changes advance the objectives of the NRC's Probabilistic Risk Assessment (PRA) Policy Statement (Reference 8.12), for enhanced decision-making and result in a more efficient use of resources and reduction of unnecessary burden. Implementation of the proposed CT will provide the following benefits:

- Allow increased flexibility in the scheduling and performance of DG maintenance.
- Allow better control and allocation of resources. Allowing on-line maintenance provides the flexibility to focus more quality resources on any required or elected DG maintenance.
- Avert unplanned plant shutdowns by utilizing the DG CT to 14 days when an AACPS is available versus 72 hours. Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve DG 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.

The results of TXU Power's probabilistic evaluation support extension of the DG CT from 72 hours to 14 days when an AACPS is available.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

TXU Power has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10CFR50.92, "Issuance of amendment," 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 (TS) changes do not significantly increase the probability of occurrence of a previously evaluated accident because the Diesel Generators (DGs) are not initiators of previously evaluated accidents involving a loss of offsite power. The proposed changes to the TS Required Actions and Completion Times (CT) do not affect any of the assumptions used in the deterministic or the Probabilistic Safety Assessment (PSA) analysis. Implementation of the proposed changes does not result in a risk significant impact. The onsite AC power sources will remain highly reliable and the proposed changes will not result in a significant increase in the risk of plant operation. This is demonstrated by showing that the impact on plant safety as measured by the increase in core damage frequency (CDF) is less than 1.0E-06 per year and the increase in large early release frequency (LERF) is less than 1.0E-07 per year. In addition, for the Completion Time changes, the incremental conditional core damage probabilities (ICCDP) and incremental conditional large early release probabilities (ICLERP) are less than 5.0E-07 and 5.0E-08, respectively. These changes meet the acceptance criteria in Regulatory Guides 1.174 and 1.177. Therefore, since the onsite AC power sources will continue to perform their functions with high reliability as originally assumed and the increase in risk as measured by ΔCDF, ΔLERF, ICCDP, and ICLERP risk metrics is within the acceptance criteria of existing regulatory guidance, there will not be a significant increase in the consequences of any accidents.

The proposed changes do not adversely affect accident initiators or precursors nor alter the design assumptions, conditions, or configuration of the facility or the manner in which the plant is operated and maintained. The proposed changes do not alter or prevent the ability of structures, systems, and components (SSCs) from performing their intended function to mitigate the consequences of an initiating event within the assumed acceptance limits. The proposed changes do not affect the source term, containment isolation, or radiological release assumptions used in evaluating the radiological consequences of an accident previously evaluated. The proposed changes are consistent with safety analysis assumptions and resultant consequences.

The proposed TS changes will continue to ensure the DGs perform their function when called upon. Extending the TS CT to 14 days, when an AACPS is available, does not affect the design, the operational characteristics, the function, or the reliability of the DGs. Additionally the CT extension to 14 days does not affect the interfaces between the DGs and other plant systems. Conversely, in the absence of an AACPS, the DG 72 hour CT will be applied. The availability of the onsite AC power system to perform its accident mitigation function is not affected by the proposed activity and thus there is no impact to the radiological consequences of any accident analysis.

To fully evaluate the effect of the changes to the CT, PSA methods were utilized. The results of this analysis show no significant increase in the Core Damage Frequency and Large Early Release Frequency.

The Configuration Risk Management Program (CRMP) in TS 5.5.18 is an administrative program that assesses risk based on plant status. The risk informed CT will be implemented consistent with the CRMP and approved plant procedures. When utilizing the 14 day extension, requirements of the CRMP per TS 5.5.18 call for the consideration of other measures to mitigate the consequences of an accident occurring while a DG is inoperable. Furthermore, administrative controls will be applied when exercising the 14 day CT extension and are adequate to maintain defense-in-depth and sufficient safety margins.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

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. The changes to the CT do not change any existing accident scenarios, nor create any new or different accident scenarios.

   In addition, the changes do not impose any new or different accident mitigation requirements or eliminate any existing requirements. The proposed changes are consistent with the safety analysis assumptions and current plant operating practice.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

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. Neither the safety analyses nor the safety analysis acceptance criteria are impacted by these changes. The proposed changes will not result in plant operation in a configuration outside the current design basis. The proposed activities only involve changes to certain TS CTs.

Therefore the proposed change does not involve a reduction in a margin of safety.

Based on the above evaluations, TXU Power concludes that the proposed amendment presents no significant hazards under the standards set forth in 10CFR50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

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." Therefore, the proposed license amendment has no impact on this regulatory requirement.

GDC 17 – Electric Power Systems, "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."

At CPSES, 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 DG 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 DG providing power to the Class 1E bus. Two independent DGs and their distribution systems are provided for each unit to supply power to the redundant onsite alternating current (AC) Power System. Each DG 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. Therefore, the proposed license amendment has no impact on this regulatory requirement.

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." Therefore, this proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.53, dated June 1973, titled "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems." The proposed license amendment has no impact on this regulatory requirement.

NRC regulatory Guide 1.62, dated October 1973, titled "Manual Initiation of Protective Actions." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.93, dated December 1974, titled "Availability of Electric Power Sources." The current CT 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 (Reference 8.4) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., CT and maintenance limitations) that the NRC considers acceptable if the number of available AC power sources is one less than the LCO. RG 1.93 specifically states, "If the available a.c. power sources are one less than the 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." RG 1.93 additionally states, "The operating time limits delineated above are explicitly for corrective maintenance activities only." Conformance with Regulatory Guide 1.93 is affected by these proposed changes. The station currently conforms to the RG. If the proposed changes are approved, the station will continue to conform to RG 1.93 with the exception that the alternate allowable Required Actions CT for restoration of a DG will be 14 days and the CT may be used for all DG maintenance if an AACPS is available. CPSES will adhere to a 72 hour CT in the absence of an AACPS.

NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988. The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases," dated July 1998. The proposed license amendment is consistent with this regulatory requirement.

NRC regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The proposed license amendment is consistent with this regulatory requirement.

NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems." These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with Safety Guide 6 (Reference 8.6) as discussed in Appendix 1A(B) of the FSAR (Reference 8.3) is not affected by this change. Redundant parts within the AC and direct current (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 buses.

NRC Safety Guide 9 (Reference 8.7), dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies." 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 is not affected by this change.

The technical analysis performed by TXU Power in Section 4, "Technical Analysis," demonstrates the ability of the DGs to perform their safety function. The increased CT continues to comply with the above regulatory requirements with the exception of RG 1.93.

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 (Reference 8.3).

In conclusion, based on the considerations discussed above, (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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

TXU Power 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 Power 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

However, a non-radiological environmental assessment will be required to ensure compliance with existing station emission permits or a new Title V permit could be required before exercising the 14 day Completion Time extension.

7.0. PRECEDENTS

7.1 By letter dated May 26, 2004 the FirstEnergy Nuclear Operating Company (FENOC) submitted similar proposed Technical Specification to extend the Completion Time for an out of service diesel generator (DG) for the Beaver Valley Power Station Unit 1 (Operating License No. DPR-66) and Unit 2 (Operating License No. NPF-73) (Reference 8.14). The NRC staff's safety evaluation report (SER) approving the plant specific license amendment requests, to extend the Completion Time for an inoperable DG from 72 hours to 14 days if an alternate AC power source was available, and issuing License Amendments No. 268 to Operating License DPR-66 and No. 150 to Operating License NPF-73 was transmitted by letter to Mr. L. William Pearce (FirstEnergy Nuclear Operating Company, Beaver Valley Power Station) by Timothy G. Colburn (USNRC), dated September 9, 2005 (Reference 8.15).

Similar license amendments have been issued for the Wolf Creek Generating Station (Reference 8.22), Diablo Canyon Power Plant (Reference 8.23), Columbia Generating Station (Reference 8.24), and Donald C. Cook Nuclear Plant (Reference 8.25).

7.2 The CPSES PRA has been used in support of several submittals to the USNRC including Risk-Informed Inservice Testing program (Reference 8.17) and Risk-Informed Inservice Inspection program (Reference 8.18). Additionally, the CPSES PRA supported License Amendment Requests to (1) remove the mode restrictions on several Technical Specification (TS) 3.8.1 surveillance requirements (Reference 8.19), (2) revise TS 3.8.1 to allow a one-time only change to extend the Action A.3 Completion Time (CT) for restoration of an inoperable offsite circuit from 72 hours to 21 days (Reference 8.20), and (3) increase the allowed outage time for a centrifugal charging pump from 72 hours to 7 days (Reference 8.21). The NRC has reviewed and approved these risk-informed submittals.

8.0 REFERENCES

8.1 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.
8.2 NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998.
8.3 Comanche Peak Steam Electric Station Final Safety Analysis Report, Docket Nos. 50-445 and 50-446.
8.4 NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974.
8.5 NRC Regulatory Guide 1.155, "Station Blackout," August 1988.
8.6 NRC Safety Guide 6, "Independence Between Redundant Standby (Onsite) Power

Sources and Between Their Distribution Systems," March 10, 1971.
8.7 NRC Safety Guide 9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971.
8.8 NRC Regulatory Guide 1.81, Revision 1, "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," January 1975.
8.9 NRC Regulatory Guide 1.53, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems," June 1973.
8.10 NRC Regulatory Guide 1.62, "Manual Initiation of Protective Actions," October 1973.
8.11 NRC Regulatory Guide 1.75, Revision 1, "Physical Independence of Electrical Systems," January 1975.
8.12 NRC 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, 1995.
8.13 WCAP-10541, "Reactor Coolant Pump Seal Performance Following A Loss of All AC Power," November 1986.
8.14 Letter to USNRC from L. William Pearce (FirstEnergy Nuclear Operating Company, Beaver Valley Power Station), May 26, 2004, "License Amendment Request Nos. 306 and 176."
8.15 Letter from Timothy G. Colburn (USNRC) to L. William Pearce (FirstEnergy Nuclear Operating Company, Beaver Valley Power Station) dated September 29, 2005, "Beaver Valley Power Station ,Unit Nos. 1 and 2 – Issuance of Amendment Re: Increase of the Emergency Diesel Generator (EDG) Allowed Outage Time from 72 Hours to 14 Days (TAC Nos. MC3331 and MC3332)."
8.16 WCAP-15622-P, "Risk-Informed Evaluation of Extension to AC Electrical Power System Completion Times," May 2001.
8.17 Letter to C. Lance Terry (TU Electric) from John H. Hannon (USNRC) dated August 14, 1998, "Approval of Risk-Informed Inservice Testing (RI-IST) Program for Comanche Peak Steam Electric Station, Units 1 and 2 (TAC Nos. M94165, M94166, MA1972, and MA1973)."
8.18 Letter to C. Lance Terry (TXU Electric) from Robert A. Gramm (USNRC) dated September 28, 2001, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Approval of Relief Request for Application of Risk-Informed Inservice Inspection Program for American Society of Mechanical Engineers Boiler and Pressure Vessel Code Class 1 and 2 Piping (TAC Nos. MB1201 and MB1202)."
8.19 Letter to M. R. Blevins (TXU Power) from Mohan C. Thadani (USNRC) dated March 15, 2006, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Issuance of Amendments Re: Technical Specification 3.8.1, "AC Sources – Operating," Mode Restrictions on Emergency Diesel Generator Surveillance (TAC Nos. MC4912 and MC4913)."
8.20 Letter to C. Lance Terry (TXU Electric) from David H. Jaffe (USNRC) dated October 9, 2001, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Issuance of Amendments Re: Extended Outage Time for Off-site Power – Single Occurrence (TAC Nos. MB1823 and MB1824)."
8.21 Letter to C. Lance Terry (TU Electric) from Timothy J. Polich (USNRC) dated

December 29, 1998, "Comanche Peak Steam Electric Station, Units 1 and 2 – Amendment Nos. 62 and 48 to Facility Operating License Nos. NPF-87 and NPF-89 (TAC Nos. M97809 and M97810)."

8.22 Letter to Rick A. Muench (Wolf Creek Nuclear Operating Corporation) from Jack Donohew (USNRC) dated April 26, 2006, "Wolf Creek Generating Station – Issuance of Amendment Re: Extended Diesel Generator Completion Times (TAC No. MC1257)."

8.23 Letter to Gregory M. Rueger (Pacific Gas and Electric Company) from Meena Khanna (USNRC) dated April 20, 2004, "Diablo Canyon Power Plant, Unit No. 1 (TAC No. MB9146) and Unit No. 2 (TAC No. MB9147) – Issuance of Amendment Re: Extensions of the Completion Times for Restoring an Inoperable Diesel Generator from 7 Days to 14 Days."

8.24 Letter to J. V. Parrish (Energy Northwest) from Brian J. Benney (USNRC) dated April 14, 2006, "Columbia Generating Station – Issuance of Amendment Re: Extension of Diesel Generator Completion Time (TAC No. MC3203)."

8.25 Letter to Mano K. Nazar (Indiana Michigan Power Company) from Deirdre W. Spaulding (USNRC) dated September 30, 2005, "Donald C. Cook Nuclear Plant, Units 1 and 2 – Issuance of Amendments Re: Safety Evaluation Regarding Allowed Outage Time Extension for the Emergency Diesel Generators (TAC Nos. MC4525 and MC4526)."

8.26 NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," Rev. 1, August 1991.

ATTACHMENT 2 to TXX-06141

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

FOR INFORMATION ONLY

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s); and

c. Automatic load sequencers for Train A and Train B.

APPLICABILITY: MODES 1, 2, 3, and 4

---NOTE---
One DG may be synchronized with the offsite power source under administrative controls for the purpose of surveillance testing.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to DGs.

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 .1 Restore required offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO

INSERT A

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the required offsite circuit(s).	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. --------------------------------	
	B.2	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR		
		------------NOTE------------- The SR need not be performed if the DG is already operating and loaded. --------------------------------	
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	.1	
	B.4 Restore DG to OPERABLE status.	72 hours
		AND
INSERT B		6 days from discovery of failure to meet LCO
		y
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)

INSERTS

INSERT A

	<u>OR</u>	
A.3.2	Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> 17 days from discovery of failure to meet LCO due to an inoperable DG with AACPS available

INSERT B

	<u>OR</u> ---------------NOTE--------------- Required Action B.4.2 and associated Completion Times are only allowed if an AACPS is available. --------------------------------------	
B.4.2	Restore DG to OPERABLE status.	14 days <u>AND</u> 17 days from discovery of failure to meet LCO

ATTACHMENT 3 to TXX-06141

PROPOSED TECHNICAL SPECIFICATIONS BASES CHANGES
(Markup For Information Only)

Pages B 3.8-7
B 3.8-10
INSERTS

.1

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. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 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 and 6 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.

INSERT B

(continued)

.1

BASES

ACTIONS (continued)

B.4

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

INSERT C

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. 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. This could lead to a total of 144 hours, 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) allowed prior to complete restoration of the LCO. The 6 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 72 hour and 6 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.

INSERT D

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)

INSERTS

INSERT A

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

INSERT B

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

The 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.3.2 establishes a limit on the maximum time allowed for one required offsite circuit and one DG to be inoperable during any single, contiguous occurrence of failing to meet the LCO if an AACPS is available. When utilizing the extended 14 day CT that will be applicable during maintenance windows to deterministically enhance the capability of the plant, the list of administrative controls discussed in TS Bases ACTION B.4.2 apply. An AACPS is described in TS Bases ACTION B.4.2. 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 14 days. This could lead to a total of 17 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 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 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 and 17 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.

INSERTS
(continued)

INSERT C

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

INSERT D

B.4.2

In Condition B, the remaining OPERABLE DG, offsite circuits, and alternate AC power source (AACPS) 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.

The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources and the AACPS, a reasonable time for maintenance, and the low probability of a DBA occurring during this period.

The Completion Time for Required Action B.4.2 establishes a 14 day allowable out-of-service time when one DG is inoperable and an AACPS is available. The 14 day Completion Time includes the normal 72 hour allowable out-of-service time which is not risk informed, followed by an 11 day extension period based on a plant specific risk analysis performed to establish the overall out-of-service time.

As a defense-in-depth measure, when the option of an extended allowable out-of-service time for an emergency DG is exercised, an AACPS will be provided with capability of supplying the same loads as the existing DGs. Thus the AACPS will be capable of supplying safe shutdown loads during a station blackout. For unplanned DG outages, an AACPS will be available upon entering the allowed outage period extension (i.e., by 72 hours into the 14 day Completion Time). For DG outages planned to exceed an initial 72 hours Completion Time, an AACPS will be provided within one hour of entering the Condition B 14 day Completion Time. In any event, if an AACPS of the required capacity is not available after entering the extended Completion Time period (after 72 hours into the Completion Time), the requirement to be in at least hot standby within the next 6 hours and in cold shutdown within the following 36 hours would apply.

The following criteria would apply to any AACPS used as a defense-in-depth measure:

1. An AACPS may be of a temporary or permanent nature and would not be required to satisfy Class 1E requirements.

2. Dynamic effects of an AACPS failure (GDC 4 events) would not adversely affect safety related plant equipment.

INSERTS
(continued)

3. An AACPS would not be required to be protected against natural phenomena (GDC 2 events) or abnormal environmental or dynamic effects (GDC 4 events).

4. An AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a LOOP. Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable.

Prior to relying on its availability, a temporary AACPS would be determined to be available by: (1) starting the AACPS and verifying proper operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe shutdown loads. Subsequently, when not in operation, a status check for availability will also be performed once every 72 hours. This check consists of (1) verifying the AACPS is mechanically and electrically ready for operations; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe shutdown loads.

Prior to relying on its availability, a permanent AACPS would be determined to be available by starting the AACPS and verifying proper operation. In addition, initial and periodic testing, surveillances, and maintenance conform to NUMARC 87-00, Revision 1, Appendix B, "Alternate AC Power Criteria" guidelines. Functional testing, timed starts and load capacity testing on a fuel cycle basis, and surveillance and maintenance will consider manufacturer's recommendations.

The following is a listing of administrative controls when utilizing the extended 14 day CT that will be applicable during DG maintenance windows (as applicable) to deterministically enhance the capability of the plant.

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

2. Weather conditions must be historically conducive to perform maintenance on the DG.

3. The offsite power supply and switchyard conditions are conducive to perform maintenance on the DG, which includes ensuring that switchyard access is monitored and controlled per procedures.

The second Completion Time for Required Action B.4.2 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

INSERTS
(continued)

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. This could lead to a total of 17 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 20 days) allowed prior to complete restoration of the LCO. The 17 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 14 day and 17 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 CT 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.

ATTACHMENT 4 to TXX-06141

RETYPED TECHNICAL SPECIFICATION PAGES

Pages 3.8-2
3.8-4

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to DGs.

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.3.1 Restore required offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
	OR	
	A.3.2 Restore required offsite circuit to OPERABLE status.	72 hours AND 17 days from discovery of failure to meet LCO due to an inoperable DG with AACPS available

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.4.1 Restore DG to OPERABLE status. OR ------------NOTE------------ Required Action B.4.2 and associated Completion Times are only allowed if an AACPS is available. -------------------------------- B.4.2 Restore DG to OPERABLE status.	 72 hours AND 6 days from discovery of failure to meet LCO 14 days AND 17 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. AND C.2 Restore one required offsite circuit to OPERABLE status.	 12 hours from discovery of Condition C concurrent with inoperability of redundant required features 24 hours

(continued)

ATTACHMENT 5 to TXX-06141

RETYPED TECHNICAL SPECIFICATION BASES PAGES

ACTIONS (continued)

A.3.1

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

The 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. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 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 and 6 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.3.2

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

The 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.

(continued)

ACTIONS (continued)

A.3.2 (continued)

The second Completion Time for Required Action A.3.2 establishes a limit on the maximum time allowed for one required offsite circuit and one DG to be inoperable during any single, contiguous occurrence of failing to meet the LCO if an AACPS is available. When utilizing the extended 14 day CT that will be applicable during maintenance windows to deterministically enhance the capability of the plant, the list of administrative controls discussed in TS Bases ACTION B.4.2 apply. An AACPS is described in TS Bases ACTION B.4.2. 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 14 days. This could lead to a total of 17 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 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 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 and 17 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)

ACTIONS (continued)

B.4.1

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.

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. This could lead to a total of 144 hours, 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) allowed prior to complete restoration of the LCO. The 6 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 72 hour and 6 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.

B.4.2

In Condition B, the remaining OPERABLE DG, offsite circuits, and alternate AC power source (AACPS) 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.

The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources and the AACPS, a reasonable time for maintenance, and the low probability of a DBA occurring during this period.

The Completion Time for Required Action B.4.2 establishes a 14 day allowable out-of-service time when one DG is inoperable and an AACPS is available. The 14 day Completion Time includes the normal 72 hour

(continued)

ACTIONS (continued)

B.4.2 (continued)

allowable out-of-service time which is not risk informed, followed by an 11 day extension period based on a plant specific risk analysis performed to establish the overall out-of-service time.

As a defense-in-depth measure, when the option of an extended allowable out-of-service time for an emergency DG is exercised, an AACPS will be provided with capability of supplying the same loads as the existing DGs. Thus the AACPS will be capable of supplying safe shutdown loads during a station blackout. For unplanned DG outages, an AACPS will be available upon entering the allowed outage period extension (i.e., by 72 hours into the 14 day Completion Time). For DG outages planned to exceed an initial 72 hours Completion Time, an AACPS will be provided within one hour of entering the Condition B 14 day Completion Time. In any event, if an AACPS of the required capacity is not available after entering the extended Completion Time period (after 72 hours into the Completion Time), the requirement to be in at least hot standby within the next 6 hours and in cold shutdown within the following 36 hours would apply.

The following criteria would apply to any AACPS used as a defense-in-depth measure:

1. An AACPS may be of a temporary or permanent nature and would not be required to satisfy Class 1E requirements.
2. Dynamic effects of an AACPS failure (GDC 4 events) would not adversely affect safety related plant equipment.
3. An AACPS would not be required to be protected against natural phenomena (GDC 2 events) or abnormal environmental or dynamic effects (GDC 4 events).
4. An AACPS would be started manually or automatically and connected to the bus when it has achieved its rated voltage and speed. The AACPS connection to the bus will occur within 15 minutes of detection of a LOOP. Thus the AACPS would have the capacity required for safe shutdown such that performance of powered equipment is acceptable.

Prior to relying on its availability, a temporary AACPS would be determined to be available by: (1) starting the AACPS and verifying proper operation; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe shutdown loads. Subsequently, when not in operation, a status check for availability will also be performed once every 72 hours. This check consists of (1) verifying the AACPS is mechanically and electrically ready for operations; (2) verifying that sufficient fuel is available onsite to support 24 hours of operation; and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe shutdown loads.

(continued)

ACTIONS (continued)

B.4.2 (continued)

Prior to relying on its availability, a permanent AACPS would be determined to be available by starting the AACPS and verifying proper operation. In addition, initial and periodic testing, surveillances, and maintenance conform to NUMARC 87-00, Revision 1, Appendix B, "Alternate AC Power Criteria" guidelines. Functional testing, timed starts and load capacity testing on a fuel cycle basis, and surveillance and maintenance will consider manufacturer's recommendations.

The following is a listing of administrative controls when utilizing the extended 14 day CT that will be applicable during DG maintenance windows (as applicable) to deterministically enhance the capability of the plant.

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).
2. Weather conditions must be historically conducive to perform maintenance on the DG.
3. The offsite power supply and switchyard conditions are conducive to perform maintenance on the DG, which includes ensuring that switchyard access is monitored and controlled per procedures.

The second Completion Time for Required Action B.4.2 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. This could lead to a total of 17 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 20 days) allowed prior to complete restoration of the LCO. The 17 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 14 day and 17 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 CT 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.

(continued)

ACTIONS (continued)

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 one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

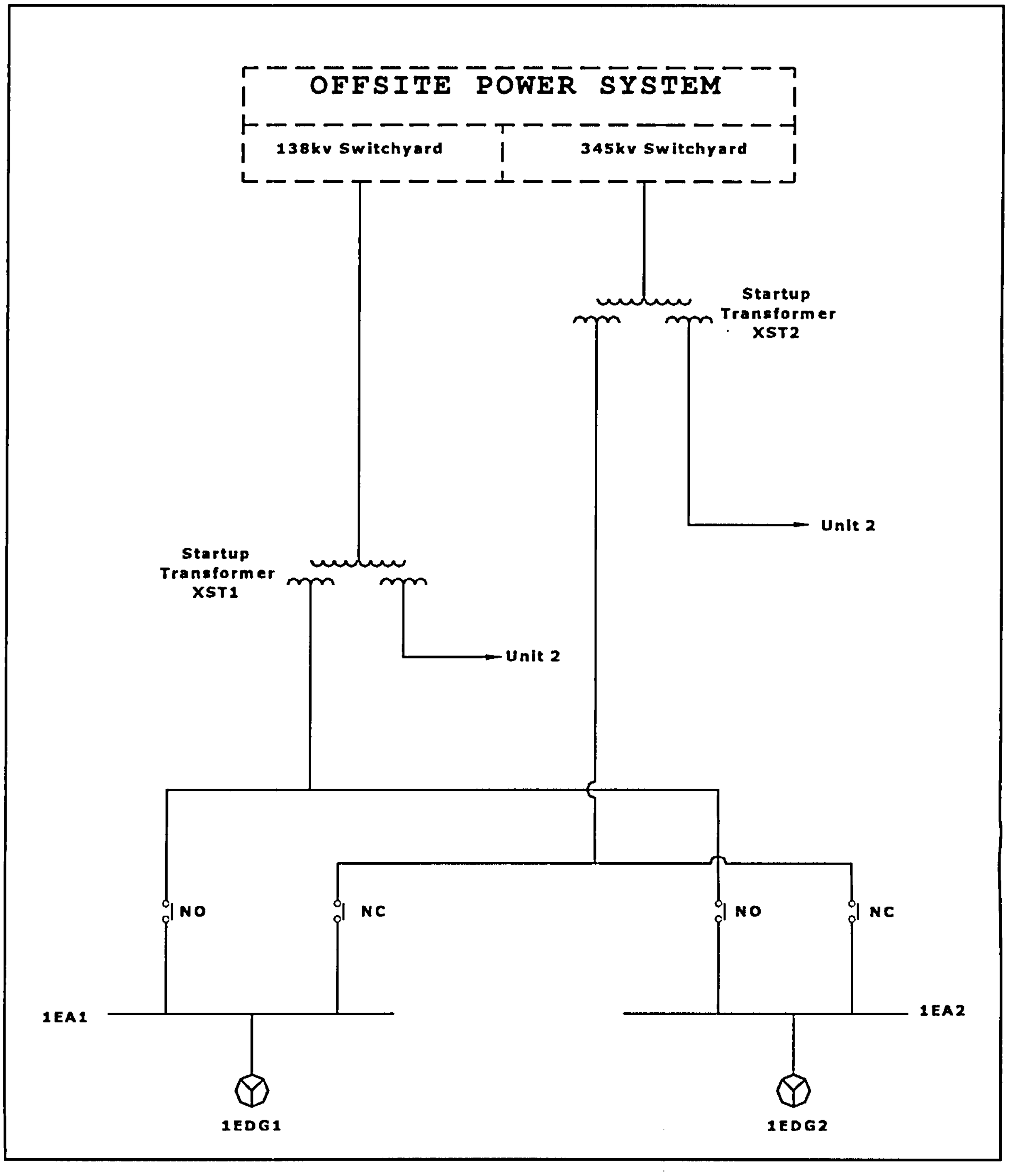
According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable.

(continued)

ATTACHMENT 6 to TXX-06141

CPSES SWITCHYARDS and DISTRIBUTION SUBSYSTEM FIGURES
(For Information Only)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345kv Switchyard
Startup
Transformer
XST2
Unit 2
Startup
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XST1
Unit 2
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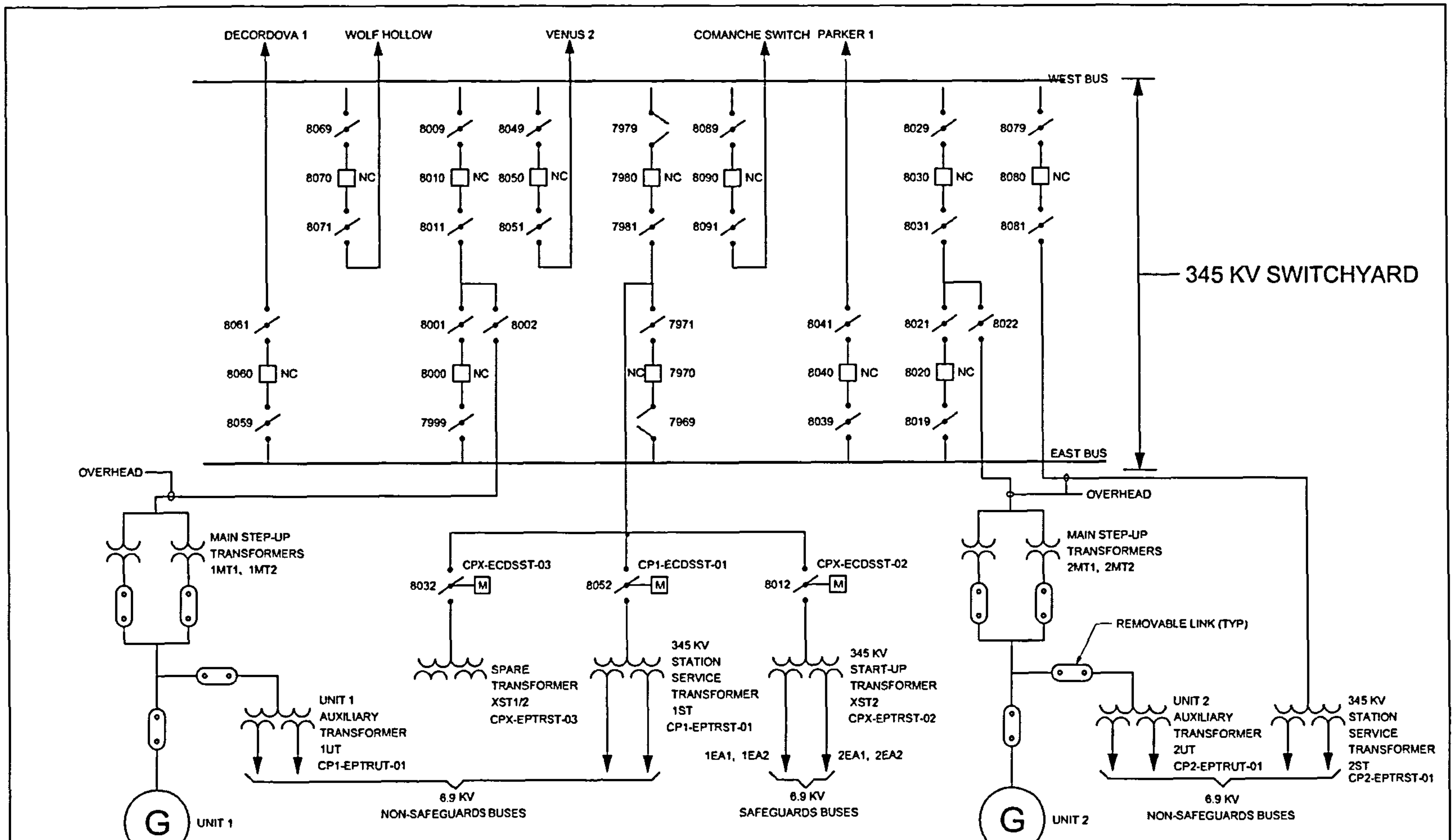
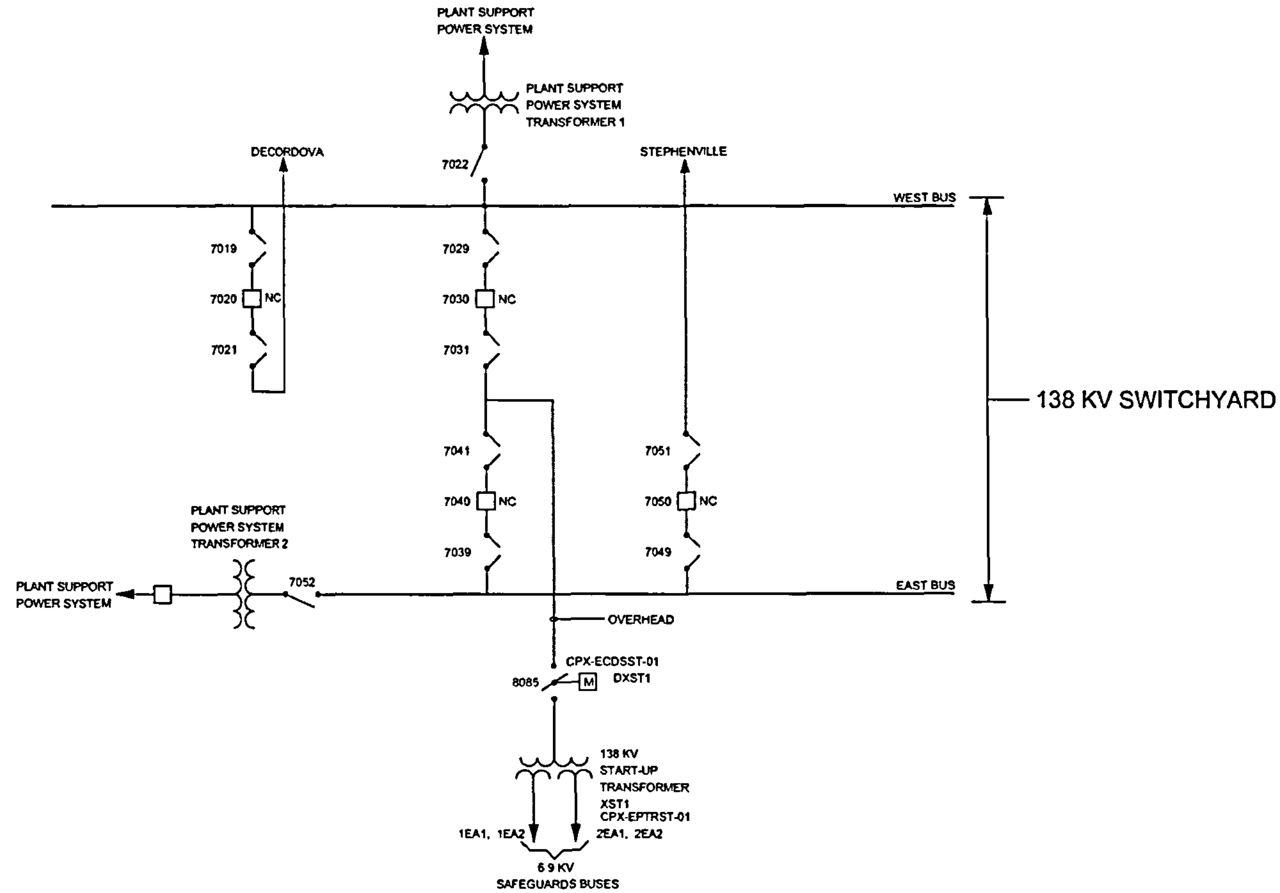


ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC
SHEET 1 OF 2



ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC
SHEET 2 OF 2