

10 CFR 50.90

June 17, 2010

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington D.C. 20555-0001

**San Onofre Nuclear Generating Station, Units 2 and 3
Docket Nos. 50-361 and 50-362**

Subject: **License Amendment Requests 259 and 245
One-Time Technical Specification (TS) Changes Applicable to
TS 3.8.1, "AC Sources – Operating"**

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Southern California Edison (SCE) hereby submits license amendment applications 259 and 245 to operating licenses NPF-10 and NPF-15 for San Onofre Units 2 and 3, respectively. License Amendment Requests 259 and 245 consist of the enclosed Proposed Change Number (PCN) 597.

The proposed amendments request that the Completion Time of Condition A of Technical Specification 3.8.1, "AC Sources – Operating," be revised on a one-time basis to allow a Completion Time of 10 days. This once-per-train change would be used once on each train on each unit and would expire at 2400 hours on June 30, 2012.

The requested change to TS 3.8.1 Completion Time is needed to allow for maintenance to be performed on the 4.16 kV Class 1E breaker cubicles on both units. Inspections have determined that a number of bottle (bushing) flanges are cracked. The existence of cracks in bottle flanges does not impact the operability or reliability of the breakers. The bottle flanges replacement effort will require extensive work and cannot be completed within the existing 72-hour (3-day) Completion Time. The requested one-time per train Completion Time change is to allow for the replacement of all bottle flanges in the 4.16 kV Class 1E breaker cubicles.

The Enclosure to this letter provides the Description and No Significant Hazards Consideration for the proposed amendments. SCE has determined that there is no significant hazards consideration associated with the proposed change and that the change is exempt from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9).

June 17, 2010

To facilitate Unit 3 breaker bottle flange replacements in the Unit 3 Cycle 16 refueling outage (currently scheduled to open breakers on October 10, 2010), SCE requests approval of these proposed license amendments by October 15, 2010, to be effective upon issuance and to be implemented within 60 days.

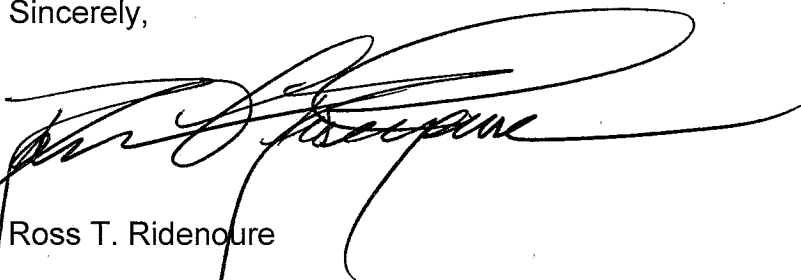
A list of regulatory commitments associated with these proposed amendments is provided in the Enclosure.

If you have any questions or require any additional information, please contact Ms. Linda T. Conklin at (949) 368-9443.

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

Executed on: JUNE 17, 2010
(Date)

Sincerely,



Ross T. Ridenoure

Enclosure:

PCN-597 with Attachments

1. List of Regulatory Commitments
2. Proposed Technical Specifications Markup Pages, Unit 2
3. Proposed Technical Specifications Markup Pages, Unit 3
4. Proposed Technical Specifications Pages, Unit 2
5. Proposed Technical Specifications Pages, Unit 3
6. Proposed Technical Specifications Bases Markup Pages, Unit 2
(Typical for Units 2 and 3 - For information only)
7. Figure III-I - 1E 4.16kV Electrical Distribution System

cc: E. E. Collins, Regional Administrator, NRC Region IV
R. Hall, NRC Project Manager, San Onofre Units 2 and 3
G. G. Warnick, NRC Senior Resident Inspector, San Onofre Units 2 and 3
S. Y. Hsu, California Department of Public Health, Radiologic Health Branch

ENCLOSURE

EVALUATION OF THE PROPOSED CHANGE

PCN-597

Technical Specification 3.8.1, AC Sources – Operating

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(Typical for Units 2 and 3 - For information only)
7. Figure III-I - 1E 4.16kV Electrical Distribution System

1. SUMMARY DESCRIPTION

PCN-597 is a request to amend Operating Licenses NPF-10 and NPF-15 for the San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, respectively.

This license amendment request will revise Technical Specification (TS): LCO 3.8.1, "AC Sources – Operating"

The proposed amendments request that the Completion Time of Technical Specification 3.8.1, "AC Sources – Operating," for Condition A, Required Action A.2, be revised to allow a Completion Time of 10 days. This is a once-per-train change to be for each unit and will expire at 2400 hours (midnight) on June 30, 2012.

The requested change to the TS 3.8.1 for Required Action A.2 is needed to allow for preventive maintenance to be performed on the 4.16 kV Class 1E breaker cubicles on both units. Inspections have determined that a number of bottle (bushing) flanges are cracked. The existence of cracks in bottle flanges does not impact the operability or reliability of the breakers. The bottle flanges replacement effort will require extensive work and cannot be completed within the existing 72-hour (3-day) Completion Time. The existing 72-hour Completion Time is entered because a bus outage, even on a shutdown unit, affects a required offsite AC power source of one train for the opposite unit. The requested once-per-train Completion Time of 10 days is to allow for the replacement of all bottle flanges in the 4.16 kV Class 1E breaker cubicles of each unit.

The proposed ten days Completion Time is based on limitations of physical restraints to perform the work. Due to these limitations, a maximum of four breaker positions can be worked simultaneously, requiring a 7 day maintenance period. An additional 1 day is required for testing, final Foreign Materials Exclusion (FME) inspections, and review and release of all orders for Operations to return to service. Operations will require approximately 1 day at the beginning for clearing the system for maintenance and 1 day at the end to return the bus to service.

2. DETAILED DESCRIPTION

This proposed change revises LCO 3.8.1, "AC Sources – Operating" Completion Time for Required Action A.2 with one required offsite circuit inoperable from:

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 <u>AND</u> Once per 8 hours Thereafter
	<u>AND</u> A.2 Restore required Offsite circuit to OPERABLE status.	72 hours <u>AND</u> 17 days from discovery of failure to meet LCO

To:

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 <u>AND</u> Once per 8 hours Thereafter
	<u>AND</u> A.2 Restore required Offsite circuit to OPERABLE status.	-----NOTE----- The Completion Time may be Extended to 10 Days once per Train prior to 7/01/2112 to perform maintenance ----- 72 hours <u>AND</u> 17 days from discovery of failure to meet LCO

3. TECHNICAL EVALUATION

3.1 Introduction

The offsite transmission system, the switchyard, and the onsite distribution system for the San Onofre Nuclear Generating Station (SONGS) are designed to provide electric power to plant electrical equipment under all plant operating conditions. The electrical system that serves SONGS 2 and 3 provides adequate reliable power sources to all SONGS 2 and 3 electrical equipment for startup, normal operation, safe shutdown, and all emergency situations.

The onsite power system includes the Class 1E power systems which provide auxiliary AC and DC power for equipment used to shut down the reactor safely following a Design Basis Event (DBE). The onsite Class 1E power system is divided into two separate redundant load groups. Each safety-related 4.16 kV load group bus of each unit is supplied by two (normal and alternate preferred) offsite power sources and one standby [Emergency Diesel Generators (EDG)] power source. In the event that the normal preferred power source fails to function, the safety-related loads connected to it will transfer to the alternate preferred power source via the opposite unit through cross-tie circuit breakers.

Technical Specification 3.8.1, "A.C. Sources - Operating" requires that in Modes 1 through 4 there are two OPERABLE qualified circuits between the offsite transmission network and the onsite electrical distribution system. The SONGS-specific Bases for Technical Specification 3.8.1 define these offsite power circuits such that two sources are required to each 4.16 kV load group bus in order to meet the Limiting Condition for Operation (LCO). Technical Specification 3.8.2, "A.C. Sources - Shutdown," requires that in MODES 5 and 6 there is one OPERABLE qualified circuit between the offsite transmission network and the onsite electrical distribution system. Technical Specification 3.8.9, "Distribution Systems - Operating," requires that in MODES 1 through 4 there are two OPERABLE electrical distribution systems. Technical Specification 3.8.10, "Distribution Systems - Shutdown," requires that in MODES 5 and 6 there is one OPERABLE electrical distribution system.

The 4.16 kV Class 1E buses of each unit must be energized in order to provide alternate preferred power to the opposite SONGS unit. In order to perform the planned bottle replacement, a 4.16 kV bus must be made inoperable on a shutdown unit. This meets TSs 3.8.2 and 3.8.10 for the shutdown unit, as there are two OPERABLE offsite power circuits to a single OPERABLE electrical distribution system. For the opposite (operating) unit, however, TS 3.8.1 is not met because one 4.16 kV bus has only one OPERABLE qualified offsite power circuit normal preferred power source. Condition A of TS 3.8.1 must be entered, resulting in a 72-hour Completion Time.

3.2 System Description

The 4.16 kV Class 1E system is designed to provide sufficient power to the 4.16 kV Class 1E loads required during normal plant operation, safe shutdown of the plant, and the mitigation and control of accident conditions. In order to ensure this capability, the 4.16 kV Class 1E System is separated into two independent redundant load groups A (bus A04) and B (bus A06). The Class 1E AC system distributes power at 4.36 kV (nominal 4.16 kV switchgear), 480 VAC, and 120 VAC to safety-related loads. Updated Final Safety Analysis Report (UFSAR) Table 8.3-1 lists all the safety-related loads supplied from the Class 1E AC system. Figure III-1, "1E 4.16kV Electrical Distribution System," is provided as Attachment 7 and shows the Class 1E AC distribution system.

Two offsite power supply feeders (normal and alternate preferred power sources) and one standby (EDG) supply feeder supply power to each 4.16 kV Class 1E load group bus of each unit. In the event that the normal preferred offsite power feeder fails to function, the safety-related loads connected to it will transfer to the alternate preferred power feeder via the opposite unit through cross-tie circuit breakers. Should both preferred power source feeders become de-energized, the safety-related loads on each bus are picked up by the standby (EDG) power source assigned to that bus.

The Class 1E AC buses are normally supplied from the offsite source through their own unit's reserve auxiliary transformers. This power source is referred to as the normal preferred power source. This is the immediately available offsite power source, even at the minimum switchyard (grid) voltage of 218 kV, under emergency conditions.

As an example, for the Unit 3 breaker bottle flanges replacement, the Unit 2 Class 1E AC buses may also be supplied from the offsite source through the Unit 2's OPERABLE Class 1E AC bus of the same load group via cross-tie breakers. The train A cross-tie is from 3XR1 to 2XR1 via cross-tie breakers at 3A04 and 2A04 and the Train B cross-tie is from 3XR2 to 2XR2 via cross-tie breakers at 3A06 and 2A06. This power source is referred to as the alternate preferred power source. This is the delayed offsite power source and this source is not designed for auto-loading (sequencing) of the required Class 1E loads following a Safety Injection Actuation Signal (SIAS) at the minimum switchyard (grid) voltage of 218 kV under emergency conditions. The alternate preferred power source is designed for providing power to Class 1E equipment of both units simultaneously at the normal switchyard (grid) operating voltage.

For each load group, one 4.16 kV feeder circuit breaker is provided for the normal preferred power source, and another 4.16 kV feeder circuit breaker is connected to the alternate preferred power source through the Class 1E bus of the opposite unit. The normal preferred power source to each bus is electrically interlocked with the alternate preferred power source. In the unlikely event of loss of the normal preferred power source to a load group during normal operation, undervoltage relays (loss of voltage relays or sustained degraded

voltage relays) on the 4.16 kV Class 1E bus will cause an automatic transfer to the alternate preferred power source, if available.

Following a unit shutdown, a third preferred power source could be established by manually removing the link in the isolated phase bus between the generator and the main power transformer of the non-operating unit through the supply breaker from the unit auxiliary transformer.

An offsite circuit includes all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E bus or buses.

During MODES 1-4, both Train A Bus 2(3) A04 and Train B Bus 2(3) A06 are required to be operable. For these buses to be declared operable, their corresponding EDG must also be operable in addition to the two physically independent normal preferred and alternate preferred power sources. As the alternate preferred power is supplied through the opposite Unit's bus, the opposite Unit's Class 1E bus is also required to be operable.

During MODES 5 and 6, only one preferred power source and one train of the 4.16 kV Class 1E system, with its associated EDG, are required to be operable as a minimum. As the alternate preferred power is supplied through the opposite unit's bus, the opposite Unit's Class 1E bus is also required to be operable.

In the event of loss of all the offsite power sources or loss of normal preferred power source (degraded or loss of voltage) concurrent with a SIAS, the Class 1E AC system will be powered from the EDG which is the standby power source.

The 4.16 kV Class 1E system is designed to remain connected to the normal preferred power source unless the SONGS switchyard voltage drops and remains below the minimum emergency voltage of 218 kV. In addition, the degraded grid and loss of voltage relays are set to protect the Class 1E equipment from degraded grid conditions.

There are no portions of the 4.16 kV Class 1E system that are shared between Units 2 and 3 during normal operation except the alternate preferred power source which is supplied through the 4.16 kV Class 1E buses of the opposite unit.

3.3 Deterministic Evaluation

The 4.16 kV Class 1E system provides a stable and reliable AC power source to all the 4.16 kV Class 1E loads during different modes of operation, and the mitigation and control of accident conditions. Two offsite power supply feeders (normal and alternate preferred power sources) and one standby (EDG) supply feeder supply power to each 4.16 kV Class 1E load group bus (Train A 2(3)

A04 and Train B 2(3) A06) of each unit. The 4.16 kV Class 1E system is designed to remain connected to the normal preferred power source unless the SONGS switchyard voltage drops below the minimum emergency voltage of 218 kV. In addition, the degraded grid and loss of voltage relays are set to protect the Class 1E equipment from degraded grid conditions.

During normal operation, if the normal preferred offsite power feeder fails to function, the safety-related loads connected to it will transfer to the alternate preferred power feeder via the opposite unit through cross-tie circuit breakers. In the event of loss of all the offsite power sources, or loss of normal preferred power source (degraded or loss of voltage) concurrent with a SIAS, the Class 1E AC system will be powered from the EDG, the standby power source, if available.

The combination of defense-in-depth and safety margin inherent in the AC power sources ensures adequate power for the 4.16 kV Class 1E loads and supports one time extension for each 4.16 kV bus (2A04, 2A06, 3A04 and 3A06) of the Completion Time from 72 hours to 10 days for once-per-train preventive maintenance.

3.3.1 Defense-In-Depth Evaluation

As described above, the 4.16 kV Class 1E system of each SONGS unit is separated into two independent load groups A (bus 2(3) A04) and B (bus 2(3) A06). The system design configuration ensures that each of the two buses is electrically and physically isolated from each other. For each load group bus, one 4.16 kV feeder circuit breaker is provided for the normal preferred power source and another 4.16 kV feeder circuit breaker is connected to the alternate preferred power source through the Class 1E bus of the similar load group of the opposite unit. Removal from service of a 4.16 kV bus of one unit (2A04 or 2A06) affects the alternate preferred power source to only one 4.16 kV bus of the other unit (3A04 or 3A06). In this configuration, the redundant 4.16 kV Class 1E bus of the operating unit would have both offsite power circuits and an onsite power source available whereas the affected 4.16 kV bus on the operating unit would have one offsite power circuit (normal preferred power source) and an onsite power source available. Each redundant 4.16 kV Class 1E bus has capability to feed all the 4.16 kV Class 1E loads required during normal plant operation, safe shutdown of the plant, and the mitigation and control of accident conditions.

The defense-in-depth philosophy requires multiple means or barriers to be in place to accomplish safety functions and prevent the release of radioactive material. During operation with an alternate preferred power circuit unavailable to one of the two redundant 4.16 kV Class 1E buses, each 4.16 kV bus will be capable to provide power for normal plant operation, safe shutdown of the plant, and the mitigation and control of accident conditions. The affected redundant 4.16 kV Class 1E bus will not be able to provide power to its loads if normal preferred power source and the associated EDG fail during a Design

Basis Event (DBE). Should a Loss of Offsite Power (LOOP) occur during a DBE, the impact will be similar whether the alternate preferred power circuit was available or unavailable as the 4.16 kV Class 1E loads would be transferred to the associated bus EDG. SONGS has a common switchyard with the same probability of losing one or both offsite circuits from the switchyard to the 4.16 kV Class 1E buses.

A complete LOOP, which is a bounding case in the Probabilistic Risk Analysis (PRA), will result in a shut down of the operating unit and unavailability of an alternate preferred power circuit to a redundant 4.16 kV Class 1E bus.

SONGS 4.16 kV Class 1E and 480 VAC Systems are in compliance with the requirements of General Design Criterion (GDC) 17. Each Class 1E load group has the required independence, capacity, redundancy, and testability to ensure the functioning of ESF systems. Independence by physical separation of components and cables minimizes the vulnerability of redundant systems to any single credible accident.

Two physically independent sources of offsite power provide power to the Class 1E Electrical Distribution System of each unit. The offsite electric power supply capacity and isolation provisions ensure that failure of a single component will not prevent safety related systems from performing their safety functions. As discussed above, one of these circuits is designed to be available immediately following a LOCA to ensure that core cooling, containment integrity, and other vital safety functions are maintained as required by 10 CFR 50 Appendix A under GDC 17. The second circuit (alternate preferred power supply) is treated as a delayed source per 10 CFR 50 Appendix A under GDC 17. The alternate preferred power source, even though automatically available, is not designed for auto loading (sequencing) of the required Class 1E loads following a LOCA at the emergency condition minimum switchyard (grid) voltage of 218 kV. The alternate preferred power source is designed for providing power to the Class 1E equipment of both units simultaneously at the normal switchyard (grid) operating voltage, 226 kV to 232 kV.

The Class 1E Electrical Distribution System is also furnished with two EDGs for each unit. Each EDG and associated Class 1E switchgear is capable of supplying sufficient power, assuming the unavailability of offsite power, for the operation of the Engineered Safety Features (ESF) systems required with or without a DBA.

SONGS design meets the requirements of 10 CFR 50 Appendix A under GDC 17 by providing two offsite power sources (normal and alternate preferred power sources) and one standby (EDG) power source to each 4.16 kV Class 1E load group bus of each unit. IEEE 765 interprets the requirements given in Appendix A of GDC 17 for Preferred Power Supply (PPS) connections to the onsite Class 1E power distribution system. Per IEEE 765, the two circuits may be connected by way of the non-Class 1E distribution system to the redundant

Class 1E bus with a single circuit to each bus but direct connection of the two circuits to each redundant Class 1E bus may further enhance availability. Thus SCE meets 10 CFR 50 Appendix A GDC 17 minimum requirements per guidance of IEEE 765, when alternate preferred power source circuit is only available to one redundant 4.16 kV Class 1E load group bus of the operating unit due to removal of the associated 4.16 kV Class 1E load group bus of the opposite unit. As such, removal of a 4.16 kV Class 1E bus of a shut down unit has minimal impact on the operating unit.

3.3.2 Safety Margin Evaluation

The proposed extension of the alternate preferred power source circuit TS Completion Time for one redundant train at a time remains consistent with the codes and standards applicable to SONGS AC sources and electrical distribution system. With the alternate preferred power source circuit unavailable to one of the two redundant 4.16 kV Class 1E buses at a time, the operating unit meets 10 CFR 50 Appendix A GDC 17 minimum requirements, per guidance of IEEE 765.

The Class 1E AC buses are normally supplied from the offsite source through their own unit's reserve auxiliary transformers. This power source is referred to as the normal preferred power source. In the event of loss of all the offsite power sources or loss of normal preferred power source (degraded or loss of voltage) concurrent with a SIAS, the Class 1E AC system will be powered from the EDG, the standby power source, if available. The 4.16 kV Class 1E system is designed to remain connected to the normal preferred power source unless the SONGS switchyard voltage drops below the minimum emergency voltage of 218 kV.

Should a LOOP occur or a normal preferred power source circuit is lost during a DBE, the impact will be effectively equivalent whether alternate preferred power circuit was available or unavailable, as the 4.16 kV Class 1E loads would be transferred to the associated bus EDG. SONGS has a common switchyard and probability of losing one or both offsite circuits from the switchyard to the 4.16 kV Class 1E buses is effectively equivalent. The simultaneous outage of a redundant 4.16 kV Class 1E bus in the opposite unit, causing the alternate preferred power source circuit to be unavailable for a single train, and failure of the normal preferred power source, along with the failure of associated EDG during a DBE, is unlikely due to postulating multiple failures. In this condition, the redundant train of 4.16 kV Class 1E load group bus will automatically actuate to mitigate the accident, and the affected unit will remain within the bounds of the accident analysis. Since the probability of these events occurring simultaneously during a planned maintenance activity on a single train has shown to be low, there is minimal safety impact due to the proposed one time per train extended Completion Time.

3.4 Probabilistic Risk Assessment (PRA)

In the SONGS PRA, the 1E 4.16 kV AC buses are modeled to be normally powered from the offsite power sources. In the event of a loss of offsite power (LOOP) event, these buses are powered from the other unit offsite power sources (through the 4.16 kV cross-tie), if available, or the own unit's same-train onsite emergency EDGs. In the event of a station blackout (SBO) event, the 1E 4.16 kV buses can be also powered from the other unit's same-train EDG via manual EDG cross-tie operator action. This unit-to-unit 4.16 kV cross-tie for the EDG is only available in accordance with 10 CFR 50.54(x).

Since the allowed outage time extensions are to be applicable to each train of 1E 4.16 kV power, calculations are performed for each bus to determine which bus outage is more risk significant. The most risk significant bus is chosen for all the risk calculations. In addition, since there is a single PRA model for SONGS Units 2 and 3, the calculations are only performed for Unit 2.

The Unit 3 buses 3A04 and 3A06 will be out of service, one train at a time, first (in 2010) during the Unit 3R16 outage. The risk calculations are performed to assess the impact on the online unit (in this case Unit 2), which will enter TS LCO 3.8.1 condition A.2 for one required offsite circuit inoperable. The risk results will also be applicable to the Unit 2R17 outage in 2012.

The impact of the proposed extension of the 1E 4.16 kV bus Completion Time on plant safety was evaluated using PRA calculations. These calculations provide a quantitative evaluation of risk in terms of average Core Damage Frequency (CDF) and Large Early Release Frequency (LERF). This evaluation included consideration of the Maintenance Rule program based on 10 CFR 50.65(a)(4) to control the performance of other potentially high risk tasks during a bus outage, as well as consideration of specific compensatory measures (or risk management actions) to manage risk. The risk evaluation was based on the three-tiered approach suggested in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decision making: Technical Specifications", as follows:

Tier 1 – PRA Capability and Insights

Tier 2 – Avoidance of Risk-Significant Plant Configurations

Tier 3 – Risk-Informed Configuration Risk Management Program

Evaluations addressing each of these tiers are provided below. The PRA model serves as the primary tool for these evaluations. Therefore, in order to establish the qualification of the PRA model, supplemental background information related to the development, application, and quality of the PRA model for SONGS are provided below.

3.4.1 SONGS PRA Model Development

The SONGS Units 2 and 3 Individual Plant Examination (IPE) for internal events study was completed in 1993 in response to NRC Generic Letter 88-20 and provides the foundation upon which the SONGS PRA is built. The PRA was then expanded following the submittal of the SONGS Units 2 and 3 IPE for external events (IPEEE) in 1995. From that time forward, the IPE and IPEEE models have been extensively revised and updated to reflect the as-built, as-operated plant using a proceduralized process to maintain the quality of the PRA.

The SONGS PRA has a broad scope characterized as a Level I and II, internal and external events, all modes PRA. A brief description of the scope's individual constituents is provided below:

- Level I: Assesses Core Damage Frequency (CDF)
- Level II: Assesses Large, Early Release Frequency (LERF)
- Internal Events: Assesses risk (CDF and LERF) due to events originating with the plant (e.g., LOCAs, loss of offsite power events, internal floods, etc.)
- External Events: Assesses risk (CDF and LERF) due to seismic and fire initiating events

All risk calculations quantitatively include the impact of internal and external events including seismic and fire. It is SONGS practice to include the contributions of internal and external events risk in applications of PRA (including all license submittals and configuration risk management practices).

The SONGS PRA utilizes the WinNUPRA PRA software code to develop event trees, fault trees, and to quantify accident sequence cutsets. To improve the quantification speed of the PRA in the Safety Monitor, the event tree model was converted to a "top logic" fault tree. The top logic methodology is consistent with the event tree / fault tree methodology and provides the same results. To ensure technical adequacy of the SONGS Safety Monitor (SM) quantification, a comprehensive verification and validation of the SM Model and results against WinNUPRA has been performed. Also, SCE periodically compares the results between the two PRA models to ensure SM model fidelity. The American Society of Mechanical Engineers (ASME) PRA Standard Peer Review of the SONGS PRA in June 2003 was performed against the Safety Monitor model and results. The top logic modeling of the event trees was explicitly reviewed during the peer review and no Facts and Observations (F&Os) regarding the use or development of the top logic modeling were identified by this review.

To verify and ensure quality, the SONGS Living PRA model has been subjected to extensive peer and regulatory review. The following sections describe the

independent reviews performed on the SONGS Units 2 and 3 internal events PRA model, seismic PRA model, and fire PRA model.

3.4.2 Internal Events PRA Quality Reviews

The following reviews have been performed on SONGS internal events PRA:

- Regulatory Review – Review of SCE’s Level I and Level II IPE and IPEEE submittals and risk-informed application-specific applications performed at various times since 1993.
- Independent Peer Review – Comprehensive independent review of the SONGS Units 2 and 3 Level I and Level II internal events all modes (full power and shutdown operations) Living PRA performed in July 2006 – April 2007.
- Westinghouse Pre-Certification Review – Evaluation of the SONGS Units 2 and 3 PRA against the Combustion Engineering Owner’s Group (CEOG) Peer Certification Guidance (which mirrors Nuclear Energy Institute [NEI] Peer review guidance NEI-001) and against the high level requirements of Revision 14a of the ASME Standard performed in February 2002.
- SCE ASME Standard Self-Assessment – Self-assessment evaluation of the SONGS Units 2 and 3 PRA Level I and Level II at power, internal events against the ASME Standard (ASME RA-S-2002) performed in March 2003.
- CEOG ASME PRA Peer Review – Utility peer review of the SONGS Units 2 and 3 Level I and Level II at power, internal events PRA against the ASME Standard (ASME RA-Sa-2002) performed in June 2003.
- Independent Assessment Against ASME PRA Standard – Consultant peer review of the SONGS Units 2 and 3 Level I and Level II at power, internal events PRA against the ASME Standard (ASME RA-Sa-2002) performed in 2004/2005.

All F&Os received during the June 2003 ASME PRA Peer Review and the Independent Assessment performed in 2004/2005 against the ASME PRA Standard have been resolved. Following the completion of the F&O resolution effort, SONGS units 2 and 3 PRA capability category assessments were performed for the supporting requirements that were rated as Capability Category I, not reviewed, or as not meeting the minimum requirements during the reviews. These assessments, documented in Appendix B of IPE-CERT-003, “Peer Review F&O Resolutions and Capability Category Assessment Report,” and IPE-CERT-004, “Independent Assessment F&O Resolutions and Capability Category Assessment Report,” determined the extent to which the revised PRA meets Capability Category II requirements in the ASME PRA Standard, Addendum B, the ASME Standard of record at the time the assessments were performed.

With the exception shown in Table 3-1 and described here, the SONGS Units 2 and 3 PRA has been assessed to meet either the Capability Category II requirement or single requirement across all three capability categories for all Supporting Requirements (SRs). The assessed impact of this one ASME Standard Supporting Requirement (which was split into two SRs in the ASME Addendum B) is shown in Table 3-1 below. The details of the assessment of the SONGS Units 2 and 3 PRA compliance with Regulatory Guide 1.200 are documented in IPE-CERT-005, "Regulatory Guide 1.200 Compliance Documentation."

These reviews demonstrate that the model represents the current plant design, configuration and current operating practices to the extent required to support risk-informed applications. The PRA maintenance process including the commitment to update the model periodically to reflect changes that impact the significant accident sequences was also reviewed and concluded that it is consistent with the PRA Standard.

**Table 3-1
ASME PRA Standard Supporting Requirements
Less than Capability Category II**

Index No. LE-C	Capability Category I	Capability Category II / III	Assessment	Impact
LE-C2a	INCLUDE conservative treatment of feasible operator actions following the onset of core damage. An acceptable conservative treatment of operator actions is provided in the event trees of NUREG/CR-6595.	Include realistic treatment of feasible operator actions following the onset of core damage consistent with applicable procedures, e.g., Emergency Operating Procedures (EOPs)/Severe Accident Management Guidelines (SAMGs), proceduralized actions, or Technical Support Center guidance.	Cat I	LERF-specific HFEs are not part of the current SCE LERF model as system-level HFEs are developed in the Level 1 analysis documentation. The current SCE LERF model does not credit SAMG operator actions or any actions taken by the Technical Support Center. Due to the design of the SONGS large, dry containment, the conservative LERF model/estimate does not have a significant impact on the results. Therefore, an ASME Capability Category I approach is acceptable with respect to this requirement.
LE-C2b	No requirement to address repair.	REVIEW significant accident progression sequences resulting in a large early release to determine if repair of equipment can be credited. JUSTIFY credit given for repair [i.e., ensure that plant conditions do not preclude repair and actuarial data exists from which to estimate the repair failure probability (see SY-A22, DA-C14, and DA-D8). AC power recovery based on generic data applicable to the plant is acceptable.	Cat I	The current SCE LERF model does not credit equipment repair. Due to the design of the rugged SONGS large, dry containment, the conservative LERF model/estimate does not have a significant impact on the results. Therefore, an ASME Capability Category I approach is acceptable with respect to this requirement.

3.4.3 Seismic PRA Quality Review

The SONGS seismic PRA was reviewed against the American Nuclear Society (ANS) External Events Standard by ABS Consulting. This review was documented in Electric Power Research Institute (EPRI) report 1009074, "Trial Plant Review of an ANS External Event PRA Standard," 2003. In the report, it states:

"Overall, it is concluded that the SONGS seismic PRA meets the requirements of Capability Category I and in most cases Capability Category II. In order to comply with all technical requirements of Category II, a full uncertainty analysis would be required that includes the uncertainties in the seismic hazard, the uncertainty in the fragilities, and the Human Reliability

Analysis (HRA). In addition, a complete sensitivity study would be required to address the effect of correlation assumptions on the computed CDF and LERF. The level of documentation would also have to be enhanced to summarize the information requested in the Standard, or to clearly list or reference all supporting Tier 2 documentation and to expand on the peer review conducted.”

The SONGS seismic PRA utilized the mean seismic hazard curve and mean equipment fragility curve. Comprehensive propagation of the uncertainties in the seismic hazard, equipment fragilities, and HRA would have provided comprehensive CDF and LERF distributions. For this application, where the risk increase is a measure of acceptability, this comment does not impact the conclusions of this analysis. In terms of seismic failure correlation, the ANS Standard requires that sensitivity studies be performed to assess the sensitivity of CDF and LERF to the assumptions used for dependency and correlations. SCE assumed complete seismic correlation for like components in a redundant safety train and no seismic correlation for dissimilar components. In the EPRI report, it states that this conservative treatment is typical and that very few seismic PRAs conducted over the past 20 years would satisfy this requirement. The EPRI report also states that “At this point in time, meeting this requirement is difficult to meet for two reasons:

- 1) There is little background and experience on correlation of seismic failures. Assignment of partial correlation on response and capacity would be subjective.
- 2) The software to treat partial correlation of seismic failures is not readily available to the public.”

Overall, it is concluded that the SONGS SEISMIC PRA meets the requirements of Capability Category I and in most cases Capability Category II.

From a seismic PRA perspective, the components providing the emergency power supply to the 1E 4.16 kV buses were all evaluated in the SONGS Seismic IPEEE. These components include the Class 1E EDGs, 4.16 kV buses, breakers and reserve auxiliary transformers (RATs). The evaluations included walk downs and inspections by a seismic review team comprised of Seismic Capability Engineers. The results of the walk downs and seismic component fragility evaluations determined that all but the reserve auxiliary transformers, which provide offsite power supply to the 1E 4.16 kV buses, were screened out of the analysis based on their high seismic capacities. The seismic failure susceptibility of the reserve auxiliary transformers was captured by their seismic fragilities in the seismic portion of the PRA model.

3.4.4 Internal Fire PRA Review

The SONGS Fire PRA was independently reviewed by Erin Engineering as part of the Fire Protection Program Self-Assessment. The review was performed against the IPEEE Fire PRA. The study, performed in October 2000 and documented in ERIN Report 108-0003.R01, identified several technical and documentation issues that were

grouped in two bins. The first bin involves “overly conservative analyses”, and the second bin involves “incomplete treatment of fire scenarios”.

- 1) Overly conservative analysis: A major part of the original fire analysis assumed that any fire would result in maximum consequential damage regardless of the location of the fire in the room. This issue was focused on the safety related train A and B switchgear rooms.
- 2) Incomplete treatment of fire scenarios: The study identified that only a large fire in the Auxiliary Feedwater (AFW) Pump room was analyzed and that smaller partially damaging fires were non-conservatively excluded.

To address these two issues, two studies were performed by ABS Consulting: 1) “Fire Risk Analysis: AFW Pump Room Reassessment, August 31, 2001,” and 2) “Fire Risk Analysis: Switchgear Room Reassessment, September 30, 2001.” The risk analysis for the switchgear room was revised to remove overly conservative assumptions and updated with newer techniques and data. The risk analysis for the AFW pump room was revised to include a comprehensive set of fire scenarios. Although additional fire scenarios were added which increased risk, the overall risk was reduced due to the presence of two automatic fire suppression systems that were not previously included in the original analysis. This resolves the aforementioned issues.

3.4.5 Tier 1: PRA Analysis

Risk-informed support for the proposed change is based on PRA calculations performed to quantify the changes in CDF and LERF resulting from the once-per-train increased Completion Time for the 1E 4.16 kV buses. To determine the effect of the proposed once-per-train 10-day Completion Time for a 1E 4.16 kV bus, the guidance suggested in Regulatory Guide 1.174 and Regulatory Guide 1.177 was used. The following Tier 1 PRA analysis elements were addressed:

- Tier 1 – Single Allowed Outage Time (AOT) and Yearly AOT Risk Analysis
- Tier 1 – Sensitivity Analyses (performed to ensure that the conclusions of the analysis would not change if parameters potentially affecting the calculation results were changed to reflect the range of uncertainty in those parameters)
- Assessment of the Cumulative Effect of Previously Granted Extensions
- Transition and Shutdown Risk Analysis

3.4.5.1 Tier 1 – Single AOT and Yearly AOT Risk Analysis

For the nominal analysis, the Train A bus 3A04 (and similarly Train B bus 3A06) was used to assess the impact of not having the power cross-tie capability for the affected train on the online Unit 2 in the following calculations specified by Regulatory Guides 1.174 and 1.177:

- R_0 : Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) (with the subject bus 3A04 test and maintenance unavailability equal to zero and nominal expected unavailabilities used for all other equipment)
- R_1 : Conditional CDF and LERF with subject bus 3A04 unavailable (with nominal expected equipment unavailabilities, except the subject bus 3A04 test and maintenance unavailability set to logical "TRUE")
- Single AOT Risk: Incremental conditional core damage probability (ICCDP)/ Incremental conditional large early release probability (ICLERP) = (Conditional CDF/LERF minus baseline CDF/LERF) times duration of proposed Completion Time (10 days)
- Yearly AOT Risk for CDF and LERF (Increase in CDF and LERF based on downtime frequency per year, f , and mean downtime duration associated with the AOT, days (d))

All calculations used a truncation limit of $1E-12$ /yr. When the Unit 3 Train A bus is out of service (OOS), the Unit 2 Train A common equipment is powered from the online unit (i.e., when bus 3A04 is OOS, the Unit 2 Train A common equipment is powered from the online Unit 2). The resulting single AOT risk (e.g., ICCDP and ICLERP) and yearly AOT risk for CDF and LERF for 1E 4.16 kV bus 3A04 are shown in Table 3-2 below.

**Table 3-2
Risk Calculations for 1E 4.16 kV Bus 2(3)A04**

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	6.16E-5 /yr	3.49E-6 /yr
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	4.74E-5 /yr	2.54E-6 /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	1.42E-5 /yr	9.50E-7 /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	3.9E-7	2.6E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	7.8E-7 /yr	5.2E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

Similarly, the resulting single AOT risk (i.e., ICCDP and ICLERP) and yearly AOT risk for CDF and LERF for 1E 4.16 kV bus 3A06 are shown in Table 3-3 below.

**Table 3-3
Risk Calculations for 1E 4.16 kV Bus 2(3)A06**

		Bus 2(3)A06	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	5.39E-5 /yr	3.05E-6 /yr
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	4.74E-5 /yr	2.54E-6 /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	6.50E-6 /yr	5.10E-7 /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	1.8E-7	1.4E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	3.6E-7 /yr	2.8E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that both 1E 4.16 kV bus outages for 2(3)A04 and 2(3)A06 meet the acceptance criteria of 5E-7 for ICCDP and 5E-8 for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of 1E-6/yr and 1E-7/yr for CDF and LERF increases, respectively, in Regulatory Guide 1.174. It is observed that the risk results for 2(3)A04 are higher than those for 2(3)A06. The Train A 1E 4.16 kV bus 2(3)A04 supports the Train A 480 VAC buses 2(3)B04 and 2(3)B24, which support Train A DC buses 2(3)D1 and 2(3)D3. The Train B 1E 4.16 kV bus 2(3)A06 supports the Train B 480 VAC buses 2(3)B06 and 2(3)B26, which support Train B DC buses 2(3)D2 and 2(3)D4. The DC buses 2(3)D1 and 2(3)D3 are more risk significant than 2(3)D2 and 2(3)D4 since they support more risk important equipment (e.g., bus 2(3)D3 supports control of the turbine-driven AFW pump steam supply valve 2(3)HV4716).

The PRA results are conservative because the 1E 4.16 kV cross-tie breakers and the EDG's common cause failure (CCF) basic events were not revised when a bus is OOS. Additionally, the Tier 1 PRA results do not credit any of the compensatory measures that will be put in place as part of the Tier 2 risk management to avoid potential risk-significant plant configurations.

3.4.5.2 Sensitivity Analyses

Sensitivity analyses were performed to ensure that the conclusions of the analysis would not change if parameters potentially affecting the calculation results were changed to reflect the range of uncertainty in those parameters. The figures of merit from the sensitivity analyses were ICCDP/ICLERP values and total increase in yearly CDF/LERF. Since the nominal risk results for bus 2(3)A04 (see Table 3-2) are higher than those for bus 2(3)A06 (see Table 3-3), the sensitivity calculations are performed for bus 2(3)A04 (the bounding case). Per guidance provided in NEI 00-04, "10 CFR 50.69 SSC Categorization Guideline", the selected initiating event frequency or component failure probability basic events were increased to their 95th percentile values to perform the sensitivity analyses. When no credit was taken for an operator action, its human error probability was increased to unity. The sensitivity analyses performed included:

- Increase the loss of offsite power initiating event frequency to its 95th percentile value to address the uncertainty in the reliability of the offsite power system and dependence of the 1E 4.16 kV buses on the EDGs.
- Increase the EDG failure probabilities to their 95th percentile values to address uncertainty in the reliability of the backup power to the 1E 4.16 kV buses.
- Increase the turbine-driven auxiliary feedwater pump (P140) failure probabilities to their 95th percentile values to address the uncertainty in the reliability of the pump, which provides the secondary side heat removal function during a station blackout (SBO) event.
- This is a once-per-train extension request to perform the 1E 4.16 kV breaker preventive maintenance and will not be used for any corrective maintenance (CM). Hence, consistent with the guidance provided in Regulatory Guide 1.177, there is no need to perform a common cause failure (CCF) sensitivity analysis for CM by replacing the 1E 4.16 kV cross-tie breaker CCF probabilities with the breaker CCF parameters (i.e., \forall factors). However, to address the uncertainty in the reliability of the 1E 4.16 kV cross-tie breakers, their CCF probabilities were increased to their 95th percentile values. This is more bounding than increasing the breaker independent failure probabilities.
- Remove credit for the manual EDG cross-tie by setting the operator action human error probability value to 1.0.

3.4.5.2.1 Increase Loss of Offsite Power Frequency to the 95th Percentile Value

In this sensitivity case, the loss of offsite power initiating event frequency was increased to its 95th percentile value to address the uncertainty in the reliability of the offsite power system and dependence of the 1E 4.16 kV buses on the EDGs. The affected basic event is INIT-LOP. Its baseline (mean) value of 2.66E-02/yr was increased to its 95th percentile value of 6.80E-02/yr. The results of the sensitivity analysis are provided in Table 3-4.

**Table 3-4
Sensitivity Calculations for 2(3)A04
Increase Loss of Offsite Power Frequency to the 95th Percentile Value**

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	6.66E-5 /yr	3.81E-6 /yr
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	4.95E-5 /yr	2.68E-6 /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	1.71E-5 /yr	1.13E-6 /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	4.7E-7	3.1E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	9.4E-7 /yr	6.2E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that a 1E 4.16 kV bus 2(3)A04 outage meets the acceptance criteria of 5E-7 for ICCDP and 5E-8 for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of 1E-6 per year for CDF increases and 1E-7 per year for LERF increases in Regulatory Guide 1.174.

3.4.5.2.2 Increase EDG Failure Probabilities to their 95th Percentile Values

In this sensitivity case, the EDG failure probabilities were increased to their 95th percentile values to address uncertainty in the reliability of the backup power to the 1E 4.16 kV buses. The affected basic events are failure to start and failure to run for all four EDGs (2G002, 2G003, 3G002, and 3G003). The baseline (mean) and the 95th percentile values for the affected EDGs basic events are summarized in Table 3-5 below.

**Table 3-5
EDG Baseline and 95th Percentile Basic Event Values**

Basic Event (BE)	Description	Baseline BE Value	95th Percentile BE Value
U-DG2G2----S	EDG 2G2 FAILS TO START ON DEMAND - TRAIN A ESF POWER	2.33E-03	5.52E-03
U-DG2G3----S	EDG 2G3 FAILS TO START ON DEMAND - TRAIN B ESF POWER	2.33E-03	5.52E-03
U-DG3G2----S	EDG 3G2 FAILS TO START ON DEMAND	2.33E-03	5.52E-03
U-DG3G3----S	EDG 3G3 FAILS TO START ON DEMAND	2.33E-03	5.52E-03
U-DG2G2--1DR	EDG 2G2 FAILS TO RUN FOR 1 DAY FOLLOWING FIRE	3.66E-02	6.13E-02
U-DG2G3--1DR	EDG 2G3 FAILS TO RUN FOR 1 DAY FOLLOWING FIRE	3.66E-02	6.13E-02
U-DG3G2--1DR	EDG 3G2 FAILS TO RUN FOR 1 DAY FOLLOWING FIRE	3.66E-02	6.13E-02
U-DG3G3--1DR	EDG 3G3 FAILS TO RUN FOR 1 DAY FOLLOWING FIRE	3.66E-02	6.13E-02

The results of the sensitivity analysis using the 95th percentile values in Table 3-5 are provided in Table 3-6.

Table 3-6
Sensitivity Calculations for 2(3)A04
Increase EDG Failure Probabilities to their 95th Percentile Values

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	<i>6.75E-5 /yr</i>	<i>3.96E-6 /yr</i>
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	<i>4.95E-5 /yr</i>	<i>2.70E-6 /yr</i>
5	Increase in CDF/LERF (Line 3 – Line 4)	<i>1.80E-5 /yr</i>	<i>1.26E-6 /yr</i>
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	4.9E-7	3.5E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	9.8E-7 /yr	6.9E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that a 1E 4.16 kV bus 2(3)A04 outage meets the acceptance criteria of 5E-7 for ICCDP and 5E-8 for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of 1E-6 per year for CDF increases and 1E-7 per year for LERF increases in Regulatory Guide 1.174.

3.4.5.2.3 Increase Turbine Driven (TD)-AFW Pump (P140) Failure Probabilities to their 95th Percentile Values

In this sensitivity case, the turbine-driven auxiliary feedwater pump (P140) failure probabilities are increased to their 95th percentile values to address the uncertainty in the reliability of the pump, which provides the secondary side heat removal function during a station blackout (SBO) event. The baseline (mean) value of 7.19E-04 for P140 failure to start probability was increased to its 95th percentile value of 2.99E-03. Similarly, the baseline (mean) value of 4.22E-03 for P140 failure to run probability was increased to its 95th percentile value of 1.15E-02. The results of this calculation are provided in Table 3-7.

Table 3-7
Sensitivity Calculations for 2(3)A04
Increase P140 Failure Probabilities to their 95th Percentile Values

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	6.52E-5 /yr	3.72E-6 /yr
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	4.94E-5 /yr	2.67E-6 /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	1.58E-5 /yr	1.05E-6 /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	4.3E-7	2.9E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	8.7E-7 /yr	5.8E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that a 1E 4.16 kV bus 2(3)A04 outage meets the acceptance criteria of 5E-7 for ICCDP and 5E-8 for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of 1E-6 per year for CDF increases and 1E-7 per year for LERF increases in Regulatory Guide 1.174.

3.4.5.2.4 Increase 1E 4.16 kV Cross-tie Breaker common cause failure CCF Probabilities to their 95th Percentile Values

This is a once-per-train extension request to perform the 1E 4.16 kV breaker bottle flange preventive maintenance only and will not be used for any corrective maintenance (CM). Consistent with the guidance provided in Regulatory Guide 1.177, there is no need to perform a CCF sensitivity analysis by adjusting the CCF probabilities of the remaining available cross-tie breakers during the outage of a 1E 4.16 kV bus and its associated cross-tie breakers due to corrective maintenance. Therefore, the 1E 4.16 kV cross-tie breaker CCF probabilities will not be replaced with the breaker CCF parameters (i.e., ∇ factors). However, to address the uncertainty in the reliability of the 1E 4.16 kV cross-tie breakers, their CCF probabilities were

increased to their 95th percentile values. This is more bounding than increasing the breaker independent failure probabilities.

The affected basic events are eleven (11) CCF to close for all four 1E 4.16 kV cross-tie breakers (2A0417 and 3A0416 for Train A and 2A0619 and 3A0603 for Train B). The baseline (mean) and the 95th percentile values for the affected breakers CCF basic events are summarized in Table 3-8 below.

**Table 3-8
Cross-tie Breaker Baseline and 95th Percentile CCF Basic Event Values**

Basic Event (BE)	Description	Baseline BE Value	95th Percentile BE Value
U-C2CC0001-N	CCF OF EP 4.1 kV BKR 2A417, 2A619, 3A416, 3A603	2.71E-06	1.58E-05
U-C2CC0002-N	CCF OF EP BKR 2A417, 2A619, 3A416	1.83E-06	1.01E-05
U-C2CC0003-N	CCF OF EP BKR 2A417, 2A619, 3A603	1.83E-06	1.01E-05
U-C2CC0004-N	CCF OF EP BKR 2A417, 3A416, 3A603	1.83E-06	1.01E-05
U-C2CC0005-N	CCF OF EP BKR 2A619, 3A416, 3A603	1.83E-06	1.01E-05
U-C2CC0006-N	CCF OF EP BKR 2A417, 2A619	9.26E-06	3.82E-05
U-C2CC0007-N	CCF OF EP BKR 2A417, 3A416	9.26E-06	3.82E-05
U-C2CC0008-N	CCF OF EP BKR 2A417, 3A603	9.26E-06	3.82E-05
U-C2CC0009-N	CCF OF EP BKR 2A619, 3A416	9.26E-06	3.82E-05
U-C2CC0010-N	CCF OF EP BKR 2A619, 3A603	9.26E-06	3.82E-05
U-C2CC0011-N	CCF OF EP BKR 3A416, 3A603	9.26E-06	3.82E-05

The results of the sensitivity analysis using the 95th percentile values in Table 3-8 are provided in Table 3-9.

**Table 3-9
Sensitivity Calculations for 2(3)A04
Increase 1E 4.16 kV Cross-tie Breaker CCF Probabilities to their 95th
Percentile Values**

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R ₁ = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	6.16E-5 /yr	3.49E-6 /yr
4	R ₀ = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	4.74E-5 /yr	2.54E-6 /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	1.42E-5 /yr	9.50E-7 /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	3.9E-7	2.6E-8
7	Downtime Frequency per year, <i>f</i>	2 /year ^a	
8	Mean Downtime Duration in AOT, <i>d</i>	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	7.8E-7 /yr	5.2E-8 /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that a 1E 4.16 kV bus 2(3)A04 outage meets the acceptance criteria of 5E-7 for ICCDP and 5E-8 for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of 1E-6 per year for CDF increases and 1E-7 per year for LERF increases in Regulatory Guide 1.174.

3.4.5.2.5 No Credit for Manual EDG Cross-Tie

The SONGS PRA model credits a manual cross-tie of the EDGs between the two units. In the event of a loss of offsite power, if the unit's own EDGs fail to provide power to the 1E 4.16 kV buses, per procedure and in accordance with the provisions of 10 CFR 50.54(x), operators effect the manual cross-tie to the opposite unit's EDG. This is a proceduralized and well-trained operator action. In this sensitivity analysis, the credit for the manual EDG cross-tie is removed from the model by setting the operator action human error probability value to 1.0. The affected basic events for the cross-tie operator action for different initiating events are U-HC3A4A660V, U-HC3A4A6SEIS60V, USHC3A4A660V50FT, USHC3A4A660VOTHR, UHHCXTIEEDG—60U and UHHCXTIEEDG—4HU.

The results of the sensitivity analysis with no credit for the manual EDG cross-tie are provided in Table 3-10.

Table 3-10
Sensitivity Calculations for 2(3)A04
No Credit for the Manual EDG Cross-tie

		Bus 2(3)A04	
		TS 3.8.1	
		CDF	LERF
1	Present Allowed Outage Time (AOT)	3 days	
2	Proposed AOT	10 days	
3	R_1 = Conditional CDF/LERF (Component UNAVAILABLE, others nominal maintenance)	$8.74E-5$ /yr	$5.79E-6$ /yr
4	R_0 = Conditional CDF/LERF (Component AVAILABLE, others nominal maintenance)	$7.78E-5$ /yr	$5.18E-6$ /yr
5	Increase in CDF/LERF (Line 3 – Line 4)	$9.60E-6$ /yr	$6.10E-7$ /yr
6	Single AOT Risk (ICCDP/ICLERP) - proposed 10 day AOT (RG 1.177) (Line 5) * 10 days / 365 days	$2.6E-7$	$1.7E-8$
7	Downtime Frequency per year, f	2 /year ^a	
8	Mean Downtime Duration in AOT, d	10 days ^b	
9	Yearly AOT Risk, ΔCDF and ΔLERF (RG 1.174) (Line 5) * (Line 8)/365 * (Line 7)	$5.3E-7$ /yr	$3.3E-8$ /yr

^a - Preventive maintenance consists of 1 PM /year /bus. No corrective maintenance bus outages will be scheduled. Therefore $f = 1 \text{ PM /yr/bus} * 2 \text{ buses} + 0 \text{ CM} = 2 \text{ /year}$

^b - It is estimated that the duration will be 10 days for each bus repair outage.

The results indicate that a 1E 4.16 kV bus 2(3)A04 outage meets the acceptance criteria of $5E-7$ for ICCDP and $5E-8$ for ICLERP in Regulatory Guide 1.177, and the acceptance criteria of $1E-6$ per year for CDF increases and $1E-7$ per year for LERF increases in Regulatory Guide 1.174.

It is noted that with 3A04 being out of service, the risk increase (i.e., $R_1 - R_0$) is lower in the case of no credit for the EDG cross-tie (see Table 3-10) compared to that when EDG cross-tie is credited (see Table 3-2). In the case of no EDG cross-tie, the online unit 1E 4.16 kV bus is impacted by only losing the offsite power source from the other unit bus (i.e., from 3A04 in this run), whereas in the case of EDG cross-tie credit, the online unit 1E 4.16 kV bus is impacted by losing both the offsite power source as well as the EDG from the other unit. As a result, the nominal (or baseline) calculations (as shown in Tables 3-2 and 3-3) and all the other sensitivity calculations (as shown in Table 3-4 through Table 3-9) are performed with credit for the manual EDG cross-tie.

3.4.6 Cumulative Effect of Previously Granted Extensions

The cumulative effect of previously granted Completion Time extensions was also evaluated, as discussed below. Eight other Completion Time changes (seven extensions and one reduction) have been granted to SONGS:

- Low Pressure Safety Injection from 3 to 7 days
- Containment Spray: from 3 to 7 days
- Safety Injection Tank from 1 hour to 24 hours
- EDG from 3 to 14 days
- Containment Isolation Valves: from 4 hours to system AOT
- Emergency Chillers: from 7 to 14 days
- DC Batteries and Battery Chargers: 2 hours to 4 days (with DC Bus Cross-tie)
- Recirculation Actuation Signal / Emergency Feedwater Actuation Signal
AOT constraint: unlimited AOT to 7 days

The SONGS PRA model has undergone changes over the years to reflect design changes, procedure changes, model scope changes (internal events, seismic and fire events), and data updates including the test and maintenance unavailability data based on actual plant component unavailabilities for which AOT extensions were granted. The average core damage and large, early release frequencies calculated for the 1E 4.16 kV bus analysis reflect the cumulative impact of the previously granted technical specification AOT time extensions and the proposed bus AOT change. Taken together, the total changes in CDF and LERF remain below the Regulatory Guide 1.174 guideline values.

3.4.7 Transition and Shutdown Risk

Transition and shutdown risk are not quantified since the AOT extension is not expected to be used for planned maintenance in MODES 2-4. Therefore, no attempt to balance any increased operational risk against transition and shutdown risk is made in this submittal. The proposed AOT extension will be used during shutdown for the opposite unit (i.e., the unit undergoing maintenance). Since that configuration will be in accordance with existing TSs no additional analysis is needed. Therefore it is a commitment of this submittal to only initiate the proposed condition in MODE 1 of the operating unit. One train will be worked at a time, thereby only affecting a single train on the operating unit.

3.4.8 Tier 2: Avoidance of Risk-Significant Plant Configurations

Reasonable assurance must be provided that risk-significant plant equipment outage configurations will not occur when a 1E 4.16 kV bus is out of service consistent with the proposed TS change. This can be determined by calculating the basic event CDF risk achievement worth (RAW) importance measures for the case where the 1E 4.16 kV bus 3A04 (the bounding case) is OOS. The calculated basic event RAW values are then converted to their associated configuration-

specific CDF values. These configuration-specific CDF values are compared with the threshold CDF value of $1E-3/\text{yr}$ provided in NUMARC 93-01, Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities" [Reference 6] for avoiding these plant configurations when scheduling equipment maintenance activities. Similar calculations are performed for LERF using a threshold value of $1E-4/\text{yr}$. When a component's basic event RAW results in a configuration-specific CDF/LERF greater than $1E-3/1E-4$ per year, the component could potentially contribute to a Tier 2 configuration.

The Tier 2 evaluation determined that there are several equipment (e.g., online unit 1E 4.16 kV buses, AFW pumps, and switchgear room normal HVAC cooling unit) that would be Tier 2 candidates.

Specifically, the following equipment is required to be made available and protected. These requirements are contained in the proposed TS Bases change associated with this license amendment request:

Online Unit Compensatory Measures - On-Line Unit

- Protect the available offsite sources: via switchyard barriers and 4.16 kV cross-tie breaker barriers.
- Protect both onsite sources (barriers) – EDGs G002 and G003, and protect the available switchgear room.
- Ensure the protected train is the train with the OPERABLE 4.16 kV cross-tie.
- Ensure common equipment (1E 480 VAC buses BQ/BS, emergency chillers, control room emergency cooling units) are aligned to the on-line unit.
- Protect AFW pumps – P141, P504, and P140.
- Protect switchgear room normal HVAC cooling unit E430 and exhaust fan MA165.
- Do not allow any switchyard work, or train work on the protected train.
- Only initiate this condition in MODE 1 of the online unit.

Outage Unit Compensatory Measures - Outage Unit

- Protect the available train offsite source: via switchyard barriers and 4.16 kV cross-tie breaker barriers.
- Protect the available train onsite source, EDG and 4.16 kV bus.

- Protect all available train safety function equipment CCW (component cooling water), SWC (saltwater cooling), SDC (shutdown cooling).
- Do not allow any work in the switchyard or on the protected train that is providing safety function fulfillment.
- Scheduling: Work the supply cubicles and cross-tie cubicle bottle flange replacements first, allowing for an "emergency" return to service.

Based on this analysis and the compensatory measures listed above for both the online unit and outage unit, there is reasonable assurance that risk-significant plant equipment configurations will not occur when a 1E 4.16 kV bus is out-of-service consistent with the proposed Technical Specification.

It is recognized that TS Limiting Condition for Operation (LCO) 3.0.3 must be entered if the other 1E 4.16 kV bus for the on-line unit becomes inoperable. In addition, increases in risk posed by potential combinations of equipment out-of-service will be managed under the SONGS 10 CFR 50.65(a)(4) Maintenance Rule (MR) risk management program.

3.4.9 Tier 3: Risk Assessment and Management Program for Planned Maintenance

SONGS maintains a "living" PRA model to evaluate the impacts of maintenance activities and planned equipment outages on plant risk levels. The impacts of these activities on calculated CDF and LERF are identified for management review on a weekly and as needed daily basis, prior to initiating these activities. This risk-informed approach to work planning provides assurance that plant risks will be controlled during the proposed once-per-train 10-day Completion Time for restoring an inoperable 1E 4.16 kV bus to operable status.

The SONGS 10 CFR 50.65(a)(4) Maintenance Rule risk management program fully satisfies the recommendations of RG 1.177 Tier 3. The SONGS risk management program performs full PRA analyses of all planned maintenance configurations at power in advance by using the Safety Monitor. The PRA model in the Safety Monitor is a comprehensive, component level, core damage, and large early release model. As discussed in Sections 3.4.2 and 3.4.6, the SONGS risk management program has been previously evaluated by the NRC in its review and approval of previously granted TS AOT extensions. Configurations that approach or exceed the NUMARC 93-01 risk limits (1E-3 /yr for CDF, 1.0E-6 for Incremental Core Damage Probability (ICDP) and 1.0E-7 for Incremental Large Early Release Probability (ILERP)) are avoided or addressed by compensatory measures. This program is administered through plant procedure SO23-XX-10, "Maintenance Rule Risk Management Program Implementation." In the Maintenance Rule Risk Management Program (MRRMP) procedure, the following guidelines are provided which control the instantaneous and cumulative incremental risk:

- The established quantitative risk management actions thresholds consider temporary risk increases associated with the configuration-specific CDF or LERF, as well as the Incremental Core Damage Probability (ICDP) and Incremental Large Early Release Probability (ILERP).
- ICDP and ILERP, for a specific planned configuration, with respect to establishing risk management actions, should be considered as follows in Table 3-11:

**Table 3-11
NUMARC 93-01 ICDP and ILERP Thresholds**

ICDP		ILERP
$> 10^{-5}$	configuration should not normally be entered voluntarily	$> 10^{-6}$
$10^{-6} - 10^{-5}$	assess non-quantifiable factors, and establish risk management actions	$10^{-7} - 10^{-6}$
$< 10^{-6}$	normal work controls	$< 10^{-7}$

- In the MRRMP program, plant configurations with an instantaneous core damage frequency of greater than 1E-3/year and/or a large early release frequency of 1E-4/year are high risk configurations that are not entered into voluntarily. In addition, the MRRMP procedure ensures that the cumulative incremental risk of planned configurations is managed to acceptable levels.

Emergent configurations are identified and analyzed by the on-shift staff for prompt determination of whether risk management actions are needed. The configuration analysis and risk management processes are fully proceduralized in compliance with the requirements of the MR(a)(4).

The SONGS risk management program requires analysis and management of all configuration risks. The 1E 4.16 kV buses are explicitly included in the MR(a)(4) scope and their removal from service is monitored, analyzed and managed using the Safety Monitor tool. In addition, possible loss of offsite power hazards (grid loading / stability, switchyard, or other electrical maintenance, and external events such as severe weather) are all modeled and explicitly accounted for in the MR(a)(4) program. When a configuration approaches the MR(a)(4) risk limits, plant procedures direct the implementation of risk management actions in compliance with the regulations. If the configuration is planned, these steps must be taken in advance.

Individually, a single bus outage does not approach the required risk management thresholds of the MR(a)(4) regulation. While combinations of unavailable equipment and/or evolutions, including a bus outage, may approach the limits and even require risk management actions, the risks arising from these configurations will be dominated by factors other than the bus outage. As a result, the risk significance of a bus outage does not warrant limitations upon other equipment.

3.5 Conclusions

The results of the deterministic evaluation and risk-informed assessment described above provide high assurance that the equipment required to safely shutdown the plant and mitigate the effects of a Design Basis Accident will remain capable of performing their safety function when the alternate preferred power source circuit is unavailable to one of the two redundant 4.16 kV Class 1E buses of the operating unit. The deterministic evaluation concluded that the proposed change is consistent with the defense-in-depth philosophy, in that: 1) there continue to be multiple means available to accomplish the required safety functions and prevent the release of radioactive material in the event of an accident; and 2) multiple barriers currently exist and additional barriers will be provided to minimize the risk associated with entering the extended alternate preferred power source TS Completion Time for one redundant train at a time so that protection of the public health and safety is assured. SONGS continues to meet 10 CFR 50, Appendix A, GDC 17 minimum requirements with the alternate preferred power source circuit unavailable to one of the two redundant 4.16 kV Class 1E buses at a time.

The risk-informed assessment concluded that the increase in plant risk is small and consistent with the NRC's Safety Goal Policy Statement, as implemented via the NRC Standard Review Plan (SRP), (NUREG-0800), Regulatory Guide (RG) 1.174, and RG 1.177.

The risk evaluation supports the once-per-train extension of the 1E 4.16 kV bus TS Completion Time from 72 hours to 10 days. The increases in annual core damage frequency and large, early release frequency associated with the proposed change to the TS Completion Time are $7.8E-7$ /yr and $5.2E-8$ /yr, respectively, which are characterized as "very small changes" by RG 1.174. The incremental conditional core damage and large, early release probabilities associated with the proposed TS allowed outage time change are $3.9E-7$ and $2.6E-8$, respectively, which are within the acceptance criteria in RG 1.177.

The sensitivity calculations confirm that the criteria in RG 1.174 and RG 1.177 are met when considering the uncertainty in key attributes of the model impacting the importance of the 1E 4.16 kV buses.

The evaluation identified configurations that could occur during an outage of a 1E 4.16 kV bus that would require Tier 2 restrictions per RG 1.177. Therefore, specific compensatory measures for both the online unit and the outage unit will be

implemented for planned 1E 4.16 kV breaker repair activities that will render a 1E 4.16 kV bus inoperable and are included in the proposed TS Bases for TS 3.8.1.

4. REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

Technical Specification (TS) 3.8.1, "AC Sources - Operating"

Technical Specification (TS) 3.8.1, "AC Sources - Operating," requires that two physically independent qualified circuits be supplied to the onsite Class 1E AC Electrical Power Distribution System. The Class 1E AC Electrical Power Distribution System consists of two 4.16 kV Engineered Safety Feature (ESF) buses, each having at least one separate and independent offsite source of power as well as a dedicated onsite EDG source.

Appendix A to Part 50 – General Design Criteria for Nuclear Power Plants

Criterion 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 assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

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

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

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 electric power supplies."

The onsite electric power system includes two safety-related load groups. The load groups are redundant in that each load group is capable of assuring items 1 and 2 above. Sufficient independence is provided between redundant load groups to ensure that postulated single failures affect only a single load group and are limited to the extent of total loss of that load group. The proposed amendment only reduces availability of alternate preferred power source circuit (delayed source) to only one redundant 4.16 kV Class 1E load group due to removal of the associated 4.16 kV Class 1E load group bus of the opposite unit. The other redundant 4.16 kV Class 1E load group bus of the operating unit will have both preferred power source circuits available. The redundant load group remains intact in order to provide for the measures specified in items 1 and 2 above.

In the case of loss of offsite power, the Class 1E system is automatically isolated from the remaining portion of the standby onsite power system. Undervoltage relays are provided on the Class 1E buses to trip the breakers if offsite power is lost.

Protection such as voltage restraint overcurrent, reverse power, and undervoltage are provided to trip the EDG circuit breaker, if abnormal conditions occur while the EDG is synchronized to the preferred power source during a test, which prevents damage to or shutdown of the EDG. In addition, each load group of the Class 1E power system is electrically and physically isolated from the redundant load group. The combination of these factors minimizes the probability of losing electric power from the standby onsite power supplies as a result of the loss of power from the transmission system.

Criterion 18 – *Inspection and testing of electric power systems.* "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 operation 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."

The Class 1E system is designed to permit:

1. Periodic inspection and testing during equipment shutdown of wiring, insulation, connections, and relays to assess the continuity of the systems and the condition of components.
2. During normal plant operation, periodic testing of the operability and functional performance of standby onsite power supplies, circuit breakers and associated control circuits, relays and buses.
3. During plant shutdown, testing of the operability of the Class 1E system as a whole. Under conditions as close to design as practical, the full operational sequence that brings the system into operation, including operation of signals of the engineered safety features actuation system and the transfer of power between the offsite and the standby onsite power systems, will be tested.

The proposed change does not affect any design features or plant operations.

4.2 Precedent

A review of license amendment requests submitted to the NRC by other licensees has identified a precedent for extending the Completion Time for TS 3.8.1. NRC letter dated October 3, 2006 "Oconee Nuclear Station Units 1, 2, and 3 - Exigent Technical Specification One-time Change Request to Extend the Allowed Outage Time for Keowee Hydro Unit 2 (KHU2) (TAC No. MD3070, MD3071, and MD3072)" revised TS 3.8.1, "AC Sources - Operating to allow a one time Completion Time of 30 days for the Oconee Nuclear Site to allow for an extended KHU2 repair outage.

4.3 Significant Hazards Consideration

Southern California Edison (SCE) has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the standards set forth in 10 CFR 50.92, Issuance of Amendment, as discussed below:

- 4.3.1 Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

This proposed Technical Specification amendment provides a one-time per train extension of the Completion Time of Condition A of Technical Specification 3.8.1, "AC Sources – Operating." Condition A will be revised on a one-time basis to allow a Completion Time of 10 days. This one-time change would be used once on each train on each unit. The revised Completion Time accommodates maintenance which is to be performed on the 4.16 kV Class 1E breaker cubicles on both units to replace cracked bottle (bushing) flanges. The bottle flange replacement requires extensive work and cannot be completed within the existing 72-hour (3-day) Completion Time.

The consequences associated with extending the Completion Time by 7 days have been evaluated in a Probabilistic Risk Assessment (PRA) and there is no significant increase in the probability or consequences of an accident previously evaluated. Further, the additional time to effect repairs to the bus bar bottles will permit SCE to avoid an unplanned forced shutdown of both SONGS Units and the potential safety consequences and operational risks associated with that action.

The minimum requirements of 10 CFR 50 Appendix A, GDC 17 with the alternate preferred power source circuit unavailable to one of the two redundant 4.16 kV Class 1E buses at a time continue to be met.

An evaluation, using Probabilistic Risk Assessment (PRA) methods, confirmed that the increases in annual core damage frequency and large, early release frequency associated with the proposed change to the TS Completion Time are characterized as "very small changes" by RG 1.174. The incremental conditional core damage and large, early release probabilities, associated with the proposed TS allowed outage time change are within the acceptance criteria in RG 1.177. Extending this Completion Time has been determined to not have a significant impact on the probability or consequences of an accident previously evaluated.

Consequently, this change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

4.3.2 Does the proposed change create the possibility of a new or different kind of accident from accident previously evaluated?

Response: No.

The request for this one-time per train Technical Specification change involves an extension of the Completion Time for Technical Specification 3.8.1, Required Action A.2, associated with restoring compliance with the Technical Specification. The proposed change will not physically alter the present plant configuration nor adversely affect how the plant is currently operated. The plant configuration that would result from use of the revised Completion Time is currently allowed by existing Technical Specifications, only for a shorter duration. This Completion Time change does not create a new or different kind of accident from any kind of accident previously evaluated.

Consequently, there is no possibility of a new or different kind of accident due to this change.

4.3.3 Does the proposed change involve significant reduction in a margin of safety?

Response: No.

This proposed Technical Specification amendment provides a one-time per train extension of the Completion Time of Condition A of Technical Specification 3.8.1, "AC Sources – Operating." Condition A will be revised on a one-time basis to allow a Completion Time of 10 days. This one-time change would be used once on each train on each unit. The revised Completion Time accommodates maintenance which is to be performed on the 4.16 kV Class 1E breaker cubicles on both units to replace cracked bottle (bushing) flanges. The bottle flanges replacement requires extensive work and cannot be completed within the existing 72-hour (3-day) Completion Time.

Further, the additional time to effect replacement of bottles will permit SCE to avoid an unplanned forced shutdown of both SONGS Units and the potential safety consequences and operational risks associated with that action.

The minimum requirements of 10 CFR 50 Appendix A, GDC 17 with the alternate preferred power source circuit unavailable to one of the two redundant 4.16 kV Class 1E buses at a time continues to be met.

An evaluation, using Probabilistic Risk Assessment (PRA) methods, confirmed that the increases in annual core damage frequency and large, early release frequency associated with the proposed change to the TS Completion Time are characterized as "very small changes" by RG 1.174. The incremental conditional core damage and large, early release probabilities, associated with the proposed TS allowed outage time change are within the acceptance criteria in RG 1.177. It has been confirmed that extending this Completion Time will not result in a significant reduction in a margin of safety.

Consequently, there is no significant reduction in a margin of safety due to this change.

Based on the above, Southern California Edison concludes that the proposed amendments present no significant hazards consideration under the substance set forth in 10 CFR 50.92(c), and accordingly, a finding of no significant hazards consideration is justified.

4.4 Conclusion

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 Commissions' regulations, and (3) the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

5. ENVIRONMENTAL CONSIDERATION

The proposed amendment does not change any requirements with respect to the installation of or use of a facility component located within the restricted area, as defined in 10 CFR 20, or change any inspection or surveillance requirement. The proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amount of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6. REFERENCES

1. U.S.N.R.C. Regulatory Guide 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes To The Licensing Basis," July 1998.
2. U.S.N.R.C. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," August 1998.
3. "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME RA-S-2002, ASME, April 2002.
4. U.S.N.R.C. Regulatory Guide 1.200, "An Approach For Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, January 2007.
5. Nuclear Energy Institute, NEI 00-04, "10 CFR 50.69 SSC Categorization Guideline," July 2005.
6. NUMARC 93-01, Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities", April 2002.
7. SO23-XX-10, Maintenance Rule Risk Management Program Implementation, Revision 3.
8. SONGS Units 2 and 3 Living PRA Model (as of February 25, 2010 | PRACP-010-0003).
9. SCE Nuclear fuels Management Probabilistic Risk Assessment Report PRA-10-005 "PRA Evaluation of Allowed Outage Time Extension for SONGS Units 2 and 3 Technical Specification 3.8.1, AC Source - Operating (Extension from 72 hours to 10 days)" dated May, 2010.

Attachment 1

List of Regulatory Commitments

List of Regulatory Commitments

The following table identifies the regulatory commitments in this document. Any other statements in this submittal represent intended or planned actions, are provided for information purposes, and are not considered to be regulatory commitments.

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE (if applicable)
	One-time/train	Continuing Compliance	
<i>Online Unit Compensatory Measures</i>			
1) SCE will			
<ul style="list-style-type: none"> Protect the available offsite source: via switchyard barriers and 4.16 kV cross-tie breaker barriers. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Protect both onsite sources (barriers) – EDGs G002 and G003, and protect the available switchgear room. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Ensure the protected train is the train with the Operable 4.16 kV cross-tie. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Ensure common equipment (1E 480 VAC bus BQ/BS, emergency chillers, control room emergency cooling units) are aligned to the on-line unit. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Protect AFW pumps – P141, P504, and P140. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Protect switchgear room normal HVAC cooling unit E430 and exhaust fan MA165. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Do not allow any switchyard work, or train work on the protected train. 	X		Expires on June 30, 2012 at 2400 hours
<ul style="list-style-type: none"> Only initiate this condition in MODE 1 of the online unit. 	X		Expires on June 30, 2012 at 2400 hours

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE (if applicable)
	One-time/train	Continuing Compliance	
<p><i>Outage Unit Compensatory Measures</i></p> <p>1) SCE will</p> <ul style="list-style-type: none"> • Protect the available train offsite source: via switchyard barriers and 4.16 kV cross-tie breaker barriers. • Protect the available train onsite source, EDG and 4.16 kV bus. • Protect all available train safety function equipment CCW (component cooling water), SWC (saltwater cooling), SDC (shutdown cooling). • Do not allow any work in the switchyard or on the protected train that is providing safety function fulfillment. • Scheduling: Work the supply cubicles and cross-tie cubicle bottle flange replacements first, allowing for an "emergency" return to service. 	X		Expires on June 30, 2012 at 2400 hours
	X		Expires on June 30, 2012 at 2400 hours
	X		Expires on June 30, 2012 at 2400 hours
	X		Expires on June 30, 2012 at 2400 hours
	X		Expires on June 30, 2012 at 2400 hours

Attachment 2

Proposed Technical Specifications Markup Pages, Unit 2

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; and
- b. Two diesel generators (DGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<p>A. One required offsite circuit inoperable.</p>	<p>A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.</p> <p><u>AND</u></p> <p>A.2 Restore required offsite circuit to OPERABLE status.</p>	<p>1 hour</p> <p><u>AND</u></p> <p>Once per 8 hours thereafter</p> <div style="border: 1px solid black; border-radius: 50%; padding: 10px; width: fit-content; margin: 10px auto;"> <p>-----NOTE----- The Completion Time may be extended to 10 days once per train prior to 7/01/2012 to perform maintenance.</p> </div> <p>72 hours</p> <p><u>AND</u></p> <p>17 days from discovery of failure to meet LCO</p>

(continued)

Attachment 3

Proposed Technical Specifications Markup Pages, Unit 3

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; and
- b. Two diesel generators (DGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<p>A. One required offsite circuit inoperable.</p>	<p>A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.</p> <p><u>AND</u></p> <p>A.2 Restore required offsite circuit to OPERABLE status.</p>	<p>1 hour</p> <p><u>AND</u></p> <p>Once per 8 hours thereafter</p> <div style="border: 1px solid black; border-radius: 50%; padding: 10px; width: fit-content; margin: 10px auto;"> <p>-----NOTE----- The Completion Time may be extended to 10 days once per train prior to 7/01/2012 to perform maintenance.</p> </div> <p>72 hours</p> <p><u>AND</u></p> <p>17 days from discovery of failure to meet LCO</p>

(continued)

Attachment 4

Proposed Technical Specifications Pages, Unit 2

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; and
- b. Two diesel generators (DGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<p>A. One required offsite circuit inoperable.</p>	<p>A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.</p> <p><u>AND</u></p> <p>A.2 Restore required offsite circuit to OPERABLE status.</p>	<p>1 hour</p> <p><u>AND</u></p> <p>Once per 8 hours thereafter</p> <p>-----NOTE----- The Completion Time may be extended to 10 days once per train prior to 7/01/2012 to perform maintenance. -----</p> <p>72 hours</p> <p><u>AND</u></p> <p>17 days from discovery of failure to meet LCO</p>

(continued)

Attachment 5

Proposed Technical Specifications Pages, Unit 3

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; and
- b. Two diesel generators (DGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<p>A. One required offsite circuit inoperable.</p>	<p>A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.</p> <p><u>AND</u></p> <p>A.2 Restore required offsite circuit to OPERABLE status.</p>	<p>1 hour</p> <p><u>AND</u></p> <p>Once per 8 hours thereafter</p> <p>-----NOTE----- The Completion Time may be extended to 10 days once per train prior to 7/01/2012 to perform maintenance. -----</p> <p>72 hours</p> <p><u>AND</u></p> <p>17 days from discovery of failure to meet LCO</p>

(continued)

Attachment 6

Proposed Technical Specifications Bases Markup Pages, Unit 2

(Typical for both Units 2 and 3 - For information only)

NOTE:

Bases change B10-004 is on pages B 3.8-7 and B 3.8-7a. Bases pages B 3.8-1 through B 3.8-6 are included for reference.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The Class 1E Electrical Power Distribution System AC sources consist of the offsite power sources (normal preferred and alternate preferred power sources), and the standby (onsite) power sources (Train A and Train B Diesel Generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred (offsite) power sources and a single DG.

In Modes 1 through 4, the normal preferred power source (Offsite circuit #1) for each unit is Reserve Auxiliary Transformers XR1 and XR2 for the specific unit. XR1 feeds one 4.16 kV ESF bus (Train A) A04 and XR2 feeds the other 4.16 kV ESF bus (Train B) A06 of the onsite Class 1E AC distribution system for each unit. The alternate preferred power source (Offsite circuit #2) is the other unit's Reserve Auxiliary Transformers XR1 and XR2, or the other unit's Unit Auxiliary Transformer XU1 through the train oriented 4.16 kV ESF bus cross-ties between the two units. The 4.16 kV ESF bus alignment in the other unit determines which transformer(s) serves as the alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Reserve Auxiliary Transformer (XR1 or XR2), then that transformer is the required alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Unit Auxiliary Transformer (XU1), then that transformer is the required alternate preferred power source.

In Modes 5 and 6, when the main generator is not operating, each Class 1E Switchgear can be connected to a third preferred power source via the Unit Auxiliary Transformers by manually removing the links in the isolated phase bus between the Main Generator and the Main

(continued)

BASES (continued)

BACKGROUND
(continued)

transformer of the non-operating (Modes 5 and 6) unit and closing the 4.16 kV circuit breaker to the Unit Auxiliary transformer of the same unit. In this alignment, the Unit Auxiliary Transformer (XU1) serves as the required normal preferred power source of the unit and the alternate preferred power source for the ESF bus(es) in the other unit.

An offsite circuit includes all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus or buses.

During a Safety Injection Actuation Signal (SIAS), certain required ESF loads are connected to the ESF buses in a predetermined sequence. Within 77 seconds after the SIAS, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are placed in service.

The standby (onsite) power source for each 4.16 kV ESF bus is a dedicated DG. DGs G002 and G003 are dedicated to ESF buses A04 and A06, respectively. A DG starts automatically on a SIAS (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal. After the DG has started, it will automatically connect to its respective bus after the offsite power supply breaker is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with a SIAS signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on a SIAS alone. Following the trip of offsite power, an undervoltage signal strips selected loads from the ESF bus. When the DG is tied to the ESF bus, the permanently connected loads are energized. If one or more ESF actuation signals are present, ESF loads are then sequentially connected to their respective ESF bus by the programmed time interval load sequence. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of preferred power in conjunction with one or more ESF actuation signals, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

(continued)

BASES (continued)

BACKGROUND (continued) Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 4700 kW with 10% overload permissible for up to 2 hours in any 24 hour period. However, for standby class of service like the San Onofre DGs the manufacturer allows specific overload values up to 116.1% of continuous duty rating based on the total hours the DG is operated per year. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite power or all onsite AC power; and
- b. A worst case single failure.

The AC sources satisfy Criterion 3 of NRC Policy Statement.

LCO Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an Anticipated Operational Occurrence (AOO) or a postulated DBA.

(continued)

BASES (continued)

LCO
(continued)

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. Required offsite circuits are those circuits that are credited and required to be Operable per LCO 3.8.1.

Each required offsite circuit must be capable of maintaining frequency and voltage within specified limits, and accepting required loads during an accident, while connected to the ESF buses.

In Modes 1 through 4, the normal preferred power source (Offsite circuit #1) for each unit is Reserve Auxiliary Transformers XR1 and XR2 for the specific unit. XR1 feeds one 4.16 kV ESF bus (Train A) A04 and XR2 feeds the other 4.16 kV ESF bus (Train B) A06 of the onsite Class 1E AC distribution system for each unit. The alternate preferred power source (Offsite circuit #2) is the other unit's Reserve Auxiliary Transformers XR1 and XR2, or the other unit's Unit Auxiliary Transformer XU1 through the train oriented 4.16 kV ESF bus cross-ties between the two units. The 4.16 kV ESF bus alignment in the other unit determines which transformer(s) serves as the alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Reserve Auxiliary Transformer (XR1 or XR2), then that transformer is the required alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Unit Auxiliary Transformer (XU1), then that transformer is the required alternate preferred power source.

In Modes 5 and 6, when the main generator is not operating, each Class 1E Switchgear can be connected to a third preferred power source via the Unit Auxiliary Transformers by manually removing the links in the isolated phase bus between the Main Generator and the Main transformer of the non-operating (Modes 5 and 6) unit and closing the 4.16 kV circuit breaker to the Unit Auxiliary transformer of the same unit. In this alignment, the Unit Auxiliary Transformer (XU1) serves as the required normal preferred power source of the unit and the alternate preferred power source for the ESF bus(es) in the other unit.

Each DG must be capable of starting, accelerating to within specified frequency and voltage limits, connecting to its respective ESF bus on detection of bus undervoltage, and resetting the 4.16 kV bus undervoltage relay logic, in less than or equal to 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading

(continued)

BASES (continued)

LCO
(continued) sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot, DG in standby with the engine at ambient conditions, and DG operating in a parallel test mode. A DG is considered already operating if the DG voltage is ≥ 4161 and ≤ 4576 volts and the frequency is ≥ 59.7 and ≤ 61.2 Hz.

Proper sequencing of loads, including tripping of nonessential loads on a SIAS, is a required function for DG OPERABILITY.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with transfer capability to the other circuit, and not violate separation criteria.

APPLICABILITY The AC sources and associated automatic load sequence timers are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

- a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
- b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

A Note prohibits the application of LCO 3.0.4b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in the circumstance.

ACTIONS

A.1

To ensure a highly reliable power source remains with the one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on

(continued)

BASES (continued)

ACTIONS

A.1 (continued)

a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

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.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 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 Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

BASES (continued)

ACTIONS

A.2 (continued)

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.

An extended Completion Time (CT) for required Action A.2 provides a 10-day one time outage per train to allow for maintenance to be performed. This CT option is for use prior to 24:00 (midnight) on 6/30/2012 and is subject to the following compensatory measures being established for both Units 2 and 3 in accordance with the associated NRC amendment for this option.

Online Unit Compensatory Measures

- Protect the available offsite sources: via switchyard barriers and 4.16 kV cross-tie breaker barriers.
- Protect both onsite sources (barriers) - EDGs G002 and G003, and protect the available switchgear room.
- Ensure the protected train is the train with the Operable 4.16 kV cross-tie.
- Ensure common equipment (1E 480 VAC buses BQ/BS, emergency chillers, control room emergency cooling units) are aligned to the on-line unit.
- Protect AFW pumps - P141, P504, and P140.
- Protect switchgear room normal HVAC cooling unit E430 and exhaust fan MA165.
- Do not allow any switchyard work, or train work on the protected train.
- Only initiate this condition in MODE 1 of the online unit.

(continued)

BASES (continued)

ACTIONS

A.2 (continued)

Outage Unit Compensatory Measures

- Protect the available train offsite source: via switchyard barriers and 4.16 kV cross-tie breaker barriers.
- Protect the available train onsite source, EDG and 4.16 kV bus.
- Protect all available train safety function equipment CCW (component cooling water), SWC (saltwater cooling), SDC (shutdown cooling).
- Do not allow any work in the switchyard or on the protected train that is providing safety function fulfillment.
- Scheduling: Work the supply cubicles and cross-tie cubicle bottle flange replacements first, allowing for an "emergency" return to service.

B.1

To ensure a highly reliable power source remains when one of the required DGs is inoperable, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as turbine driven auxiliary feedwater pumps, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

(continued)

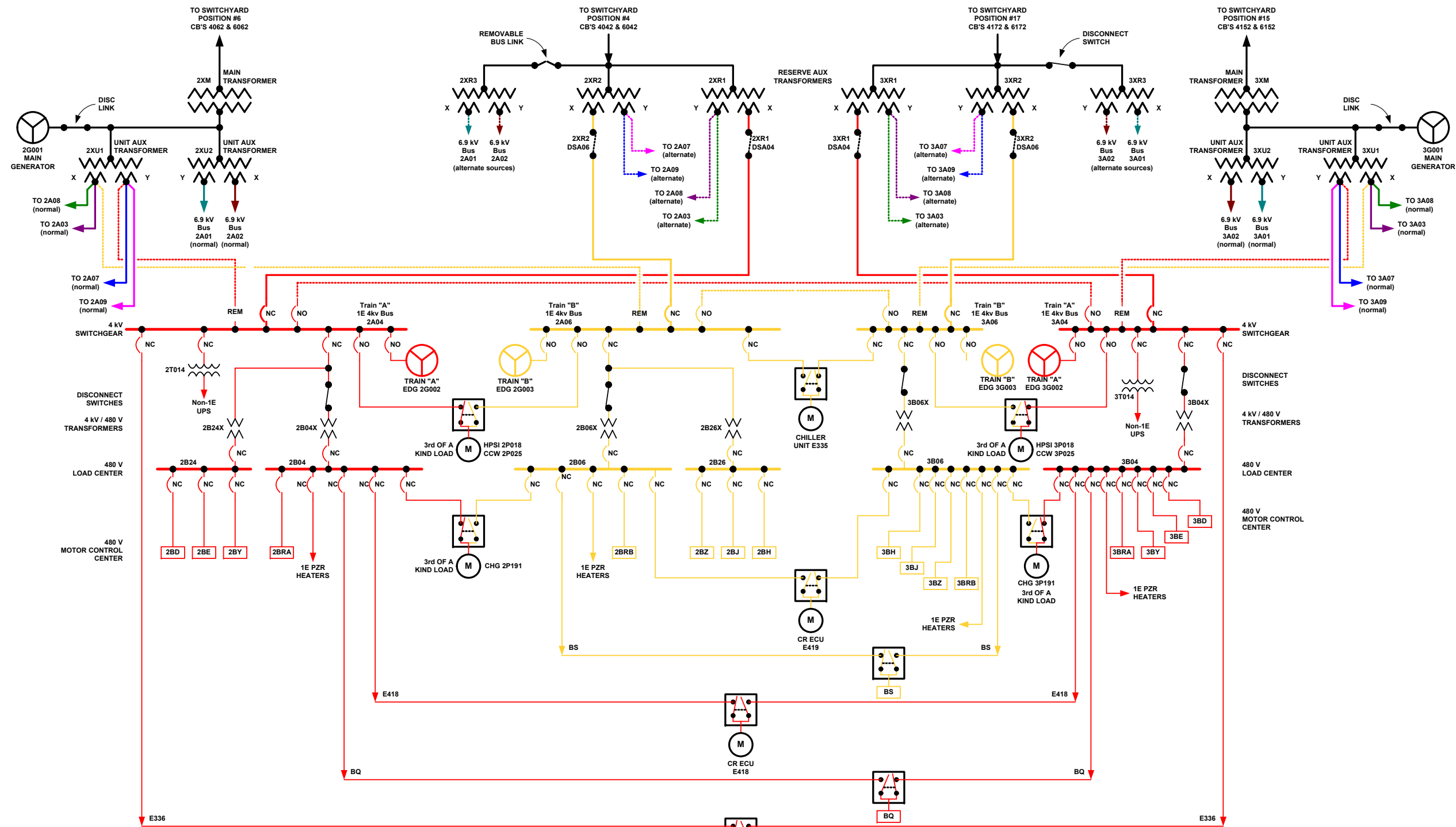
Attachment 7

Figure III-1 - 1E 4.16kV Electrical Distribution System

FIGURE III-1: 1E 4.16 kV ELECTRICAL DISTRIBUTION SYSTEM

| R

Best Available Image



LEGEND			
— 220 kv	— Train A - 4kv A04	— Non-1E 4kv A08	NC NORMALLY CLOSED
— 22 kv	— Train B - 4kv A06	— Non-1E 4kv A03	NO NORMALLY OPEN
— 6.9 kv - A01	— Train A - 480v B04	— Non-1E 4kv A07	REM BREAKER REMOVED
— 6.9 kv - A02	— Train B - 480v B06	— Non-1E 4kv A09	— NORMAL POWER
		— Lighting L01 & L02	— ALTERNATE POWER

RESOURCES:
30101