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PG&E Letter DCL-15 -091

U.S. Nuclear Regulatory Commission 10 CFR 50.90

ATTN: Document Control Desk
Washington, D.C. 20555-0001

Diablo Canyon Units 1 and 2
Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
License Amendment Request 15-04
Exigent Revision to Technical Specification 3.8.9, "Distribution Systems – Operating"

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.90, Pacific Gas and Electric Company (PG&E) hereby requests approval of the enclosed proposed amendment to Facility Operating License Nos. DPR-80 and DPR-82 for Units 1 and 2 of the Diablo Canyon Power Plant, respectively. The enclosed license amendment request (LAR) proposes to revise Technical Specification (TS) 3.8.9, "Distribution Systems – Operating."

The proposed change would revise the TS 3.8.9, Condition B, Required Action B.1 Completion Time (CT) from 2 hours to 24 hours.

This amendment request represents a risk-informed licensing change. The proposed change meets the criteria of Regulatory Guide (RG) 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.177, Revision 1, "An Approach for Plant Specific, Risk-Informed Decision making: Technical Specifications," for risk-informed changes.

On June 29, 2015, the output breaker for Unit 1 Inverter IY-14 spuriously opened deenergizing Vital 120 Volts Alternating Current (VAC) instrument panel PY-14. The breaker was closed, reenergizing PY-14 and returning IY-14 and PY-14 to Operable.

On July 20, 2015, the output breaker for Unit 1 Inverter IY-14 spuriously opened again. As with the June 29, 2015, occurrence, the breaker was closed, reenergizing PY-14 and returning IY-14 and PY-14 to Operable.

Due to the issues with the IY-14 output breaker, PG&E evaluated options for replacing the breaker online and determined current TS CTs are insufficient to support online replacement.

The output breaker for Inverter IY-14 is associated with TS 3.8.7, "Inverters – Operating." TS 3.8.7, Condition A, "One Required inverter inoperable," Required Action A.1 includes a note to, "Enter applicable Conditions and Required Actions of LCO 3.8.9, 'Distribution Systems – Operating' with any vital 120 VAC bus deenergized." TS 3.8.7, Condition A has a CT of 24 hours, however, TS 3.8.9, Condition B, only has a 2-hour CT. PG&E reviewed other TS and Equipment Control Guidelines (ECGs) impacted due to an inoperable 120 VAC vital bus subsystem inoperable and did not identify any actions less than 24 hours associated with a plant shutdown.

The purpose of this LAR is to revise TS 3.8.9, in support of replacing electronic style inverter output breakers online.

PG&E requests NRC approval of this LAR within three weeks of the submittal date to support replacing the output breaker for Unit 1 Inverter IY-14 online as a prudent measure to prevent potential transients, should the breaker spuriously open, and to improve overall plant safety. The existing output breaker design utilizes an electronic trip device to monitor the breaker current and initiate opening when appropriate. The apparent cause of the spurious opening of the breaker is false actuation of the electronic trip device in the breakers. To eliminate this apparent cause, the existing electronic style output breakers will be replaced with nonelectronic style breakers. Prompt replacement of the output breaker for Inverter IY-14 would eliminate this electronic trip failure mechanism. An installed spare output breaker on IY-14 has been temporarily paralleled with the normal output breaker to reduce the impact of a normal output breaker spurious opening, however, since both breakers are of the same electronic design, there is still a potential for loss of inverter output power from false actuation of the electronic trip device in the breakers. If this were to occur, and operators were unable to restore the inverter output power, the 24-hour CT would be sufficient to replace the normal output breaker and avoid an unnecessary shutdown.

Additionally, PG&E plans to replace all electronic style output breakers for the vital IY inverters with nonelectronic style breakers during or before Unit 1 Refueling Outage 19 (1R19) and Unit 2 Refueling Outage 19 (2R19). The 1R19 outage is scheduled for October 2015. The 2R19 outage is scheduled for May 2016. Exigent review and approval of this TS change would also provide additional opportunity (more maintenance outage windows) to appropriately schedule and replace Unit 2 IY breakers prior to 2R19.

The changes in this LAR are not required to address an immediate safety concern.

PG&E requests approval of this LAR within three weeks of the submittal date. PG&E requests the license amendment(s) be made effective upon NRC issuance, to be implemented within 7 days from the date of issuance.

PG&E makes no regulatory commitments (as defined by NEI 99-04) in this letter. This letter includes no revisions to existing regulatory commitments.

In accordance with site administrative procedures and the Quality Assurance Program, the proposed amendment has been reviewed by the Plant Staff Review Committee.

Pursuant to 10 CFR 50.91, PG&E is sending a copy of this proposed amendment to the California Department of Public Health.

If you have any questions or require additional information, please contact Mr. Hossein Hamzehee at 805-545-4720.

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

Executed on August 12, 2015.

Sincerely,

Barry S. Allen

Barry S. Allen
Vice President – Nuclear Services

mjrm/4557/50709593
Enclosure
cc: Diablo Distribution
cc/enc: Marc L. Dapas, NRC Region IV
Siva P. Lingam, NRR Project Manager
Gonzalo L. Perez, Branch Chief, California Dept of Public Health
John Reynoso, NRC Acting Senior Resident Inspector

Evaluation of the Proposed Change

License Amendment Request 15-04
Revision to Technical Specification 3.8.9, "Distribution Systems – Operating"

ATTACHMENTS:

1. Technical Specification Page (Markups)
2. Technical Specification (Retyped page)
3. Technical Specification Bases Page (Markups)

Evaluation of the Proposed Change

1. SUMMARY DESCRIPTION

This letter is an exigent request to amend Operating Licenses DPR-80 and DPR-82 for Units 1 and 2 of the Diablo Canyon Power Plant (DCPP), respectively.

The proposed change would revise the Operating Licenses to revise Technical Specification (TS) 3.8.9, "Distribution Systems – Operating."

The proposed change would revise the TS 3.8.9, Condition B, Required Action B.1 Completion Time (CT) from 2 hours to 24 hours to, "Restore 120 VAC vital bus subsystem to OPERABLE status," for "One 120 VAC vital bus subsystem inoperable."

2. DETAILED DESCRIPTION

<u>Proposed Amendment</u>

The proposed change would revise the TS 3.8.9, Condition B, Required Action B.1 CT from 2 hours to 24 hours to "Restore 120 VAC vital bus subsystem to OPERABLE status" for "One 120 VAC vital bus subsystem inoperable."

B.	One 120 VAC vital bus subsystem inoperable.	B.1	Restore 120 VAC vital bus subsystem to OPERABLE status.	~~2~~ hours 24

The proposed TS change is noted on the marked-up TS page provided in Attachment 1. The revised TS page is provided in Attachment 2. The TS Bases change is contained for information only in Attachment 3.

This LAR proposes a change to TS 3.8.9, "Distribution Systems – Operating." A change to TS 3.8.9, "Distribution Systems – Operating," was also proposed in PG&E Letter DCL-13-106, "Revision to Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 1, 'Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4B,'" dated November 25, 2013. If this LAR is approved prior to approval of the LAR discussed above, a new TS retyped page will be provided.

<u>System Description</u>

The onsite Class 1E electrical power distribution system is designed with three 4160 V and 480 V Vital Buses (F, G, and H) and three 125 VDC vital buses. The plant protection system (PPS) is designed with four Input Channels (I, II, III, and IV) powered from four 120 VAC Vital Buses (1, 2, 3, and 4). The four channels provide input to the solid state protection system (SSPS) Trains A and B. Each SSPS train actuates engineered safety feature (ESF) equipment in the three vital alternating current (AC) and direct current (DC) buses and certain nonvital equipment in the nonvital AC and DC buses.

There are three AC electrical power subsystems, each comprised of a primary ESF 4.16 kV bus and secondary 480 and 120 V buses, distribution panels, motor control centers and load centers. Each 4.16 kV ESF bus has two separate and independent offsite sources of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to the 500 kV offsite source. After a loss of this normal 500 kV offsite power source to a 4.16 kV ESF bus, a transfer to the alternate 230 kV offsite source is accomplished by utilizing a time delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16 kV ESF bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries.

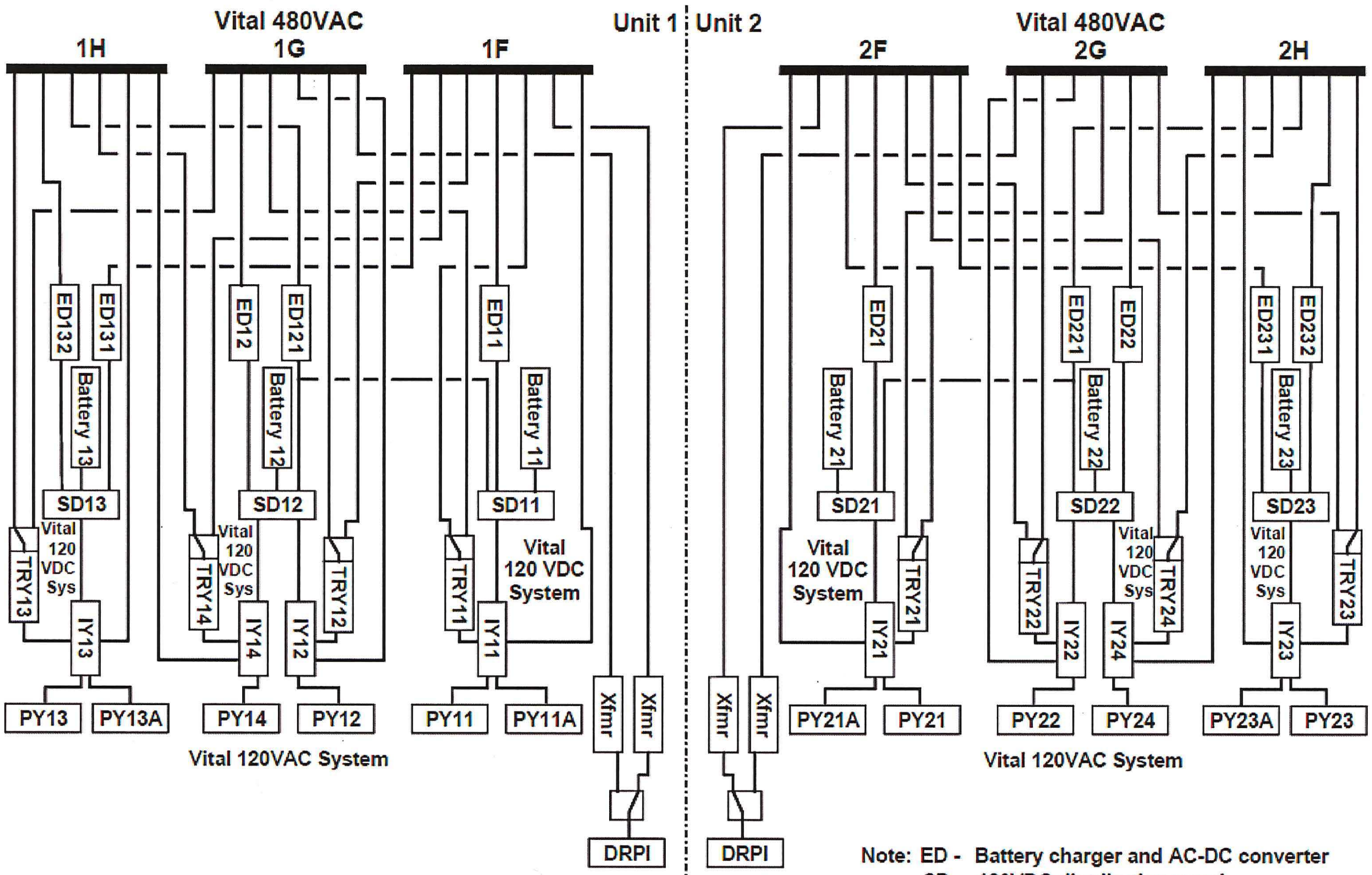
The 120 VAC vital buses are arranged in four buses and are normally powered from the inverters. The alternate power supply for the 120 VAC vital buses are Class 1E constant voltage source transformers powered from the same bus as the associated inverter, and its use is governed by Limiting Conditions for Operation (LCO) 3.8.7, "Inverters - Operating." Each constant voltage source transformer is powered from a Class 1E AC bus. In addition, each inverter can be powered from a bus other than its associated bus.

The Class 1E AC, DC, and 120 VAC vital bus electrical power distribution systems 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.

Figure 1 below provides an overview of the vital instrument power distribution system design.

Figure 1

Vital Instrument Power Distribution Overview



Note: ED - Battery charger and AC-DC converter
SD - 120VDC distribution panel
IY - UPS and DC - AC inverter (bypassable)
PY - 120VAC distribution panel
TRY- 480VAC-120VAC transformer and regulator

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Purpose for Proposed Amendment

On June 29, 2015, the output breaker for Unit 1 Inverter IY-14 spuriously opened deenergizing Vital 120 VAC Instrument Panel PY-14. The breaker was closed, reenergizing PY-14 and returning IY-14 and PY-14 to Operable.

On July 20, 2015, the output breaker for Unit 1 Inverter IY-14 spuriously opened again. As with the June 29, 2015, occurrence, the breaker was closed, reenergizing PY-14 and returning IY-14 and PY-14 to Operable.

Due to the issues with the breaker, PG&E evaluated options for replacing the breaker online and determined the current TS CT is insufficient to support online replacement.

The output breaker for Inverter IY-14 is associated with TS 3.8.7, "Inverters – Operating." TS 3.8.7, Condition A, "One Required inverter inoperable," Required Action A.1 includes a note to, "Enter applicable Conditions and Required Actions of LCO 3.8.9, 'Distribution Systems – Operating' with any vital 120 VAC bus deenergized." TS 3.8.7, Condition A has a CT of 24 hours, however, TS 3.8.9, Condition B, only has a 2-hour CT. PG&E reviewed other TS and Equipment Control Guidelines (ECGs) impacted due to an inoperable 120 VAC vital bus subsystem inoperable and did not identify any actions less than 24 hours associated with a plant shutdown.

The purpose of this LAR is to revise TS 3.8.9 in support of replacing 120 VAC vital bus inverter output breakers online.

PG&E requests NRC approval of this LAR within three weeks of the submittal date to support replacing the output breaker for Unit 1 Inverter IY-14 online as a prudent measure to prevent potential transients, should the breaker spuriously open, and to improve overall plant safety. The existing output breaker design utilizes an electronic trip device to monitor the breaker current and initiate opening when appropriate. The apparent cause of the spurious opening of the breaker is false actuation of the electronic trip device in the breakers. To eliminate this apparent cause, the existing electronic style output breakers will be replaced with nonelectronic style breakers. Prompt replacement of the output breaker for Inverter IY-14 would eliminate this electronic trip failure mechanism. An installed spare output breaker on IY-14 has been temporarily paralleled with the normal output breaker to reduce the impact of a normal output breaker spuriously opening, however, since both breakers are of the same electronic design, there is still a potential for loss of inverter output power from false actuation of the electronic trip device in the breakers. If this were to occur, and operators were unable to restore the inverter output power, the 24-hour CT would be sufficient to replace the normal output breaker and avoid an unnecessary shutdown.

Additionally, PG&E plans to replace all electronic style output breakers for the vital IY inverters with nonelectronic style breakers during or before Unit 1 Refueling Outage 19 (1R19) and Unit 2 Refueling Outage 19 (2R19). The 1R19 outage is scheduled for October 2015. The 2R19 outage is scheduled for May 2016. Exigent review and approval of this TS change would also provide additional opportunity (more maintenance outage windows) to appropriately schedule and replace Unit 2 electronic style output breakers for IY inverters prior to 2R19.

The output breakers for IY inverters are currently Operable. The new nonelectronic style breakers would eliminate a possible susceptibility to false actuation of the electronic trip device.

Risk-Informed Licensing Change

This LAR represents a risk-informed licensing change. The proposed change meets the criteria of Regulatory Guide (RG) 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," for risk-informed changes.

RG 1.177, Revision 1, discusses the acceptable reasons for requesting TS changes. The following categories apply to this LAR:

> Improvement to operational safety: A change to the TS can be made due to reductions in the plant risk or a reduction in the occupational exposure of plant personnel in complying with the TS requirements.
>
> Consistency with risk basis in regulatory requirements: TS requirements can be changed to reflect improved design features in a plant or to reflect equipment reliability improvements that make a previous requirement unnecessarily stringent or ineffective. TS may be changed to establish consistently-based requirements across the industry or across an industry group.
>
> Reduce unnecessary burdens: The change may be requested to reduce unnecessary burdens in complying with current TS requirements, based on operating history of the plant or the industry in general. This includes extending CT (1) that are too short to complete repairs when components fail with the plant at-power, (2) to complete additional maintenance activities at-power to reduce plant down time, and (3) provide increased flexibility to plant operators.

3. TECHNICAL EVALUATION

Background

There were 5 spurious Vital Instrument AC (IY inverter) output breaker openings in the last 9 years:

May 6, 2006:
Spurious opening of Inverter IY-24 output breaker during Unit 2 Refueling Outage 13

June 6, 2012:
Spurious opening of Inverter IY-14 output breaker during Unit 1 Refueling Outage 17

February 23, 2013:
Spurious opening of Inverter IY-23 output breaker during Unit 2 Refueling Outage 17

June 29, 2015:
Spurious opening of Unit 1 Inverter IY-14 output breaker on-line

July 20, 2015:
Spurious opening of Unit 1 Inverter IY-14 output breaker on-line

The apparent cause for the spurious actuation or opening of the output breakers, which causes a loss of their Vital Instrument AC Bus Distribution Panels, is a false actuation of the electronic trip device. All IY inverter output breaker failure events occurred at different time periods. In the Probabilistic Risk Assessment (PRA) analysis it is conservatively assumed that there is a potential for failure causes that may be common to the output breakers of all the Instrument AC Channels.

The extended allowed outage time (AOT) for the 120 VAC vital bus subsystem will be used to replace the current IY inverter electronic style breakers with nonelectronic style breakers which do not utilize an electronic trip device so they will not be susceptible to false electronic trip device actuation. Operating experiences from the industry and manufacturer of the breakers indicate that the nonelectronic style breakers are the industry norm for nuclear applications and DCPP is an outlier by having the electronic style output breakers.

Replacing the output breaker for Inverter IY-14 requires the removal of the affected channel of Instrument AC power from service. The analysis performed in the PRA calculation file provides a risk-informed basis for changing the LCO CT from 2 hours to 24 hours.

Impact on Defense-In-Depth and Safety Margins

Impact on Defense-in Depth

There are four 120 VAC vital buses that are normally powered by the Class 1E UPS inverters. The Class 1E UPS inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. The PPS is designed with four Input Channels (I, II, III, and IV) powered from the four 120 VAC Vital Buses (1, 2, 3, and 4). The four channels provide input to the SSPS Trains A and B. Two of the four 120 VAC vital buses have two separate 120 VAC power panels (PY panel) and the other two 120 VAC vital buses have only one associated power panel. Each 120 VAC panel is powered from the inverter though an output breaker on the inverter.

The SSPS input relays are fail-safe (with the exception of the input circuits that initiate containment spray (CS) and the radiation monitoring channels that initiate containment ventilation isolation).

Each SSPS train receives inputs on Channels 1, 2, 3, and 4. Inputs are powered from 120 VAC Class 1E busses associated with that Channel (1, 2, 3, and 4). Contacts of the SSPS input relays provide inputs to the logic portion of SSPS where the coincidence logic (2-out-of-3, 2-out-of-4) is performed. Therefore, loss of one 120 VAC Class 1E bus to the SSPS inputs, with the input fail-safe (exceptions noted above), will not prevent any of the SSPS trains from performing their coincident logic function.

The SSPS output slave relays require power to actuate. The output relays of SSPS Train A are powered by PY11/21 (Unit 1/Unit 2) and Train B are powered by PY14/24 (Unit 1/Unit 2). Therefore, deenergizing a 120 VAC Class 1E bus will only affect one train of SSPS output relays. The other train remains functional to perform its intended safety function.

The 120 VAC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

The 120 VAC vital buses are support systems for Reactor Trip Instrumentation, Engineered Safety Feature Actuation System (ESFAS) Instrumentation, and several other TS 3.3 Instrumentation Systems. In addition, the 120 VAC vital buses also support other TS equipment such as the Auxiliary Feedwater System by providing power to their associated control systems.

Loss or removal from service of any single PY panel to support IY inverter output breaker replacement will not cause a significant plant transient or reactor trip unless there is additional equipment out-of-service that will cause the coincidence for an ESF function to be met. Depending on the PY panel affected, the unexpected loss of a PY panel may cause system actuations that require Operator response. This is due to loss of systems such as the RCS Letdown flowpath, charging controls, and RCS makeup controls. In order to perform maintenance on the IY inverter output breakers, a planned deenergization of a PY panel would mitigate any plant control issues, by preemptively placing the plant in a condition where an operator response action would not need to be taken in a rapid fashion (e.g., excess letdown placed in service). No new accidents or transients would be introduced by increasing the CT for restoration of a PY panel.

Reactor Trip Instrumentation and ESFAS Instrumentation redundancy may be reduced while the PY panel is deenergized. Many bistables will be placed in the trip condition, lowering the redundancy to where a single channel failure would cause a reactor trip or safety injection. This would increase the likelihood of an inadvertent ESF initiation slightly. This potential impact of an inadvertent ESF initiation is not considered risk significant and has been evaluated as part of the overall PRA risk assessment.

No new operator actions related to the CT extensions are required to maintain plant safety. The Emergency Operating Procedures provide for instructions on how to respond to the anticipated system degradations in the event that a reactor trip or safety injection may occur during the period a PY panel is deenergized. Specifically, the EOPs provide direction on operation of the Auxiliary Feedwater System, the Steam Generator (SG) Power Operated Relief Valves, the Charging System, and RCS Letdown System.

The proposed change needs to meet the defense-in-depth principle, which consists of a number of elements. These elements and the impact of the proposed change on each follow:

- A reasonable balance among prevention of core damage, prevention of containment failure and consequence mitigation is preserved.

  Providing an extended CT for the inverter output breakers has a very small impact on Core Damage Frequency (CDF), a small impact on consequence mitigation, and a very small impact on Large Early Release Frequency (LERF). The proposed change does not significantly degrade the ability of one barrier to fission product release and compensate with an improvement of another. The balance between prevention of core damage and prevention of containment failure and consequence mitigation is maintained.

  Furthermore, no new accidents or transients are introduced with the proposed change. While in the TS condition for one 120 VAC vital bus subsystem inoperable, the likelihood of an inadvertent ESF initiation is slightly increased. This potential impact of an inadvertent ESF initiation is not considered risk significant and has been evaluated as part of the overall PRA risk assessment.

- Over-reliance on programmatic activities to compensate for weaknesses in plant design.

  The proposed change will provide sufficient time to replace electronic style inverter output breakers with nonelectronic style breakers. All safety systems will still perform their design functions and there will be no additional reliance on additional systems, procedures, or operator actions. The calculated risk increase for the CT changes is very small and additional control processes are not required to be put into place to compensate for any risk increase.

- System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system.

  The proposed change will provide additional time to complete existing TS 3.8.9, Required Action B.1. While in TS 3.8.9, Condition B, equipment redundancy is reduced.

  There are no proposed plant modifications that would impact plant design redundancy, independence, or diversity of the components, or on the ability of the plant to respond to a plant trip, safety injection (SI), or accident with diverse systems. With a single failure impacting a 120 VAC vital bus subsystem, or Condition entry for a limited duration, the redundant Operable equipment will continue to perform their design functions.

  The proposed change will allow for earlier replacement with components that are more reliable (not susceptible to false actuation of the electronic trip device) and will remain reliable after the proposed change is implemented.

- Defenses against potential common cause failures are maintained and the potential for introduction of new common cause failure mechanisms is assessed.

  Defenses against common cause failures are maintained. The CT extensions requested are not so significant that any new common cause failure mechanisms would occur. In addition, the operating environment for these components remains the same; therefore, new common cause failure modes are not expected. The number, design, and types of components used for 120 VAC subsystems remain the same with these changes so the system maintains the potential against common cause failures.

- Independence of barriers is not degraded.

  The barriers protecting the public and the independence of these barriers are maintained. Assessment of maintenance activities per 10 CFR 50.65 in accordance with existing PG&E procedures ensures that multiple systems will not be out-of-service simultaneously during the extended CT that could lead to degradation of these barriers, and an increase in risk to the public. In addition, the extended CT does not provide a mechanism that degrades the independence of the fuel cladding, RCS, and containment barriers.

- Defenses against human errors are maintained.

  No new operator actions related to the CT extensions are required to maintain plant safety. No changes to current operating, or maintenance procedures are required due to these changes. The increase in the CT provides additional time and flexibility to allow replacing the IY inverter electronic output breakers without requiring an unplanned shutdown or cooldown.

<u>Impact on Safety Margins</u>

During the time period that a 120 VAC PY panel is out-of-service per the proposed revision to TS 3.8.9 Condition B CT, there will not be a significant reduction in a margin of safety for any Design Basis Accidents (DBAs) evaluated in the Updated Final Safety Analysis Report (UFSAR).

The four 120 VAC systems are electrically downstream of the 4 kV and 480 VAC ESF equipment that is required for DBA mitigation. The removal from service due to maintenance or a single failure of any IY inverter output breaker can only impact a single ESF train of equipment. Therefore, a single failure in the instrumentation and control power supply system or its associated power supplies does not prevent the minimum safety functions from being performed.

Therefore, during the LCO time period, there will be at least one full train of ESF equipment available such that the Emergency Core Cooling System, Auxiliary Feedwater (AFW) system, and containment heat removal system comprised of CS and Containment Fan Cooler Units (CFCUs) will be able to ensure that adequate core cooling, RCS integrity and containment integrity are maintained for all DBAs.

The associated loss of instrument and control power for any given 120 VAC system will not adversely impact any ESF or reactor protection function. Any affected reactor protection bistables (with the exception of the input circuits that initiate CS and the radiation monitoring channels that initiate containment ventilation isolation) will be placed in the conservative tripped state and at least one full train of ESF equipment will be available during the LCO time period. In addition, the operator actions required to respond to the affected equipment for a deenergized 120 VAC panel are already explicitly defined and addressed in current operating procedures. In summary, there will be no adverse impact on any ESF equipment function required for DBA mitigation such that no fission product barrier design basis limit for fuel, RCS, or containment or safety limit described in the UFSAR will be exceeded or altered.

The proposed change does not involve a significant reduction in a margin of safety per 10 CFR 50.92.

Therefore, the proposed change has no impact on safety margins.

Assessment of Impact on Risk

A PRA has been performed using the NRC's three-tier approach described in RG 1.177, Revision 1. The three tiers consist of:

Tier 1 - PRA Capability and Insights
Tier 2 - Avoidance of Risk-Significant Plant Configurations, and
Tier 3 - Risk-Informed Configuration Risk Management

Tier 1: PRA Capability and Insights

PRA Capability

The scope, level of detail, and quality of the Diablo Canyon PRA (DCPRA) are sufficient to support a technically defensible and realistic evaluation of the risk change from this proposed CT extension. The DCPRA used in this evaluation is a full scope Level 1 and Level 2 PRA model that addresses internal, seismic and fire events at full power. The DCPRA is performed for Unit 1, but it is equally applicable to Unit 2 because the two units are essentially identical.

The DCPRA is based on the original 1988 DCPRA that was performed as part of the Long Term Seismic Program (LTSP). The DCPRA-1988 was a full scope Level 1 PRA that evaluated internal and external events. The DCPRA was subsequently updated to support the Individual Plant Examination (IPE) (1991) and the Individual Plant Examination for External Events (IPEEE) (1993). Since 1993, several other updates have been made to incorporate plant and procedure changes, update plant specific reliability and equipment unavailability data, improve the fidelity of the model, incorporate Westinghouse Owners Group (WOG) Peer Review comments, and support other applications, such as On-line Maintenance, Risk-Informed In-Service Inspection, Emergency Diesel Generator CT Extension, and Mitigating System Performance Index (MSPI).

The current Model of Record DC03 has been Peer Reviewed against RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Capability

Category II, for Internal Events and Internal Flooding. All Facts and Observations have been resolved.

As a result of the sound basis of the original model as documented in NUREG-0675 (Supplemental Safety Evaluation Report (SSER) No. 34) and NUREG/CR-5726, the considerable effort to incorporate the latest industry insights into the PRA, self-assessments, and certification peer reviews, PG&E is confident that the results of the risk evaluation are technically sound and consistent with the expectations for PRA quality set forth in RG 1.177, Revision 1, and RG 1.174, Revision 2.

Fire and Other External Events

A fire analysis was conducted as part of the original DCPRA-1988. The NRC reviewed the LTSP and issued SSER No. 34 accepting DCPRA-1988. The Fire PRA was updated to support the 1993 IPEEE. Other than control room (CR) and cable spreading room (CSR) fire scenarios, the Fire PRA quantifies the CDF associated with most internal fire initiating events using the same linked event tree models as the internal and seismic events analyses. Separate event trees using conservative assumptions were developed for evaluating CR and CSR fire scenarios.

The evaluation of high winds, external floods, and other external events, which was done as part of the IPEEE, revealed no potential vulnerabilities. The proposed extension to the CT for the Instrument AC distribution panel has negligible effect on the risk profile at DCPP from other external events.

RG 1.177, Revision 1, requires the evaluation of the proposed change on the total risk (i.e., on-line and shutdown risk). This evaluation only quantifies the risk associated at power with the inoperable IY-14 output breaker, if the IY-14 output breaker is inoperable for a time period greater than that allowed by the current TS (2 hours). This is conservative since the risk of the TS-driven shutdown is not used to balance the risk of the proposed extended CT.

Methodology

The general methodology of evaluating the proposed change in accordance with RG 1.174, Revision 2, and RG 1.177, Revision 1, involves identifying the areas of concern relating to the IY-14 output breaker when in an out-of-specification (OOS) design limit condition and quantifying its impact on risk.

The areas of concern are creating a new initiating event (IE), an increase in the frequency of an existing IE(s), and impact on the consequence of an IE. The steps for the analysis of the impact of common cause failures of the IY inverter output breaker on the availability/reliability of the Instrument AC power system, and the risk impact of removing the affected channel of Instrument AC power for the replacement of IY-14 Inverter Output Breaker 52-14B2, are as follows:

- Data Analysis - IY inverter output breaker failure rate and common cause failure factors evaluation

- System Analysis – Develop top event model to account for common cause failures of IY inverter output breakers. Account for common cause failures of the output breakers in the Loss of two Channels Instrument AC power initiating event

- Event Sequence/Tree Analysis – Evaluate the risk metrics of base model

- Evaluate the risk impact of removing one channel of Instrument AC power from power for breaker replacement

1. Data Analysis

    The generic failure rate for the IY inverter output breakers is updated using the DCPP failure event data and operating experience for these breakers. The Bayesian Update approach is adopted in the component failure rate update the following case:

- Last 10 years of operating experience (January 1, 2005, through July 21, 2015).

Table 1 shows a summary of the operating hours for the IY inverter output breakers for 10 years. With 5 IY inverter output breakers failure events occurring in the last 10 years, the updated failure rates for the IY inverter output breakers are shown in the table below:

Component Failure Rate per Hour	Designator	Mean	5th%	Median	95th%
Generic Prior	ZTCB2T	1.71E-07	4.85E-08	1.38E-07	3.88E-07
10 years' Operating Experience*	ZTCB10	3.20E-06	8.78E-07	2.86E-06	6.08E-06

*The Bayesian updated generic data had the lambda values adjusted by Riskman because of number of breaker failures.

The hours in Table 1 below are a gross estimation of operability hours and do not take into account maintenance unavailability. A Maintenance Rule Unavailability search was performed to find the total unavailability for all eight IY inverters over the last 10 years for all modes of operation, including refueling outages (Modes 1 – 6 and Defueled). The total unavailability is 10,279 hours and comes mostly from the refueling outages when major maintenance of the panels occurs. This gives a total for Units 1 and 2 of 1,076,390 operating hours. Performing the Bayesian update with these total operating hours is shown below compared to using the gross estimation of hours. The mean value is actually slightly less due to the shape of the distribution. The impact is insignificant.

Operating Hours for Bayesian update	Mean	5th%	Median	95^{th}%
1,086,669	3.20E-06	8.78E-07	2.86E-06	6.08E-06
1,076,390	3.14E-06	9.77E-07	2.85E-06	5.83E-06

Table 1. operating hours for the IY inverter output breakers for 10 years

Unit 1 Breakers			
Year	**Hours per year**	**No. of Breakers**	**Breaker operation hours**
2005	8760	6	52,560
2006	8760	6	52,560
2007	8760	6	52,560
2008	8784	6	52,704
2009	8760	6	52,560
2010	8760	6	52,560
2011	8760	6	52,560
2012	8784	6	52,704
2013	8760	6	52,560
2014	8760	6	52,560
2015 (to July 21)	4365	6	26,190
Total Unit 1			**552,078**
Unit 2 Breakers			
2005	8760	6	52,560
2006	8760	6	52,560
2007	8760	6	52,560
2008	8784	6	52,704
2009	8760	6	52,560
2010	8760	6	52,560
2011	8760	6	52,560
2012	8784	6	52,704
2013	8760	6	52,560
2014 (Jan - Oct) *	7296	6	43,776
2014 (Nov -Dec) *	1464	3	4,392
2015 (to July 21)	4365	3	13,095
Total Unit 2			**534,591**
Total Units 1 and 2			**1,086,669**

Note * Three of the Unit 2 electronic style trip output breakers were replaced with nonelectronic style breakers in October of 2014.

To model common cause failures of the IY inverter output breakers, generic common cause Multiple-Greek-letter (MGL) factors for the breaker tripping open (transfer open) failure mode were used from the report "CCF Parameter estimations 2012 Update" by the US NRC. Since there are no common cause factors developed for breaker spurious actuation (due to the absence of data for such events), the Generic Rate CCF distributions from Section 2.2.2 of the above report for a group/population of 6 components (CCCG=6) was used for this analysis. The MGL common cause failure factors (point estimate values) are presented in the table below:

MGL Factors (designator)	**Point Estimate Value**
Beta Factor (ZBCB2T)	2.39E-02
Gamma Factor (ZGCB2T)	7.32E-01
Delta Factor (ZDCB2T)	6.17E-01
Epsilon Factor (ZECB2T)	5.02E-01
Mu Factor (ZUCB2T)	4.32E-01

2. System Analysis

Top Event ICC was developed to model the output breakers of the 4 channels of Instrument AC Inverters:

Vital Instrument Inverter IY-11 output breakers: IY11B2, IY11B3
Vital Instrument Inverter IY-12 output breaker: IY12B2
Vital Instrument Inverter IY-13 output breakers: IY13B2, IY13B3
Vital Instrument Inverter IY-14 output breaker: IY14B2

Top Event ICC is a multi-state top event with each state associated with the status of the output breaker(s) of each of the Instrument AC Channels/Inverters.

The output breaker failure rate and the MGL factors developed in Step 1 were used in the modeling and quantification of the split fraction value for each state of Top Event ICC. Common cause failures of the output breakers are included in the ICC top event model.

The top event II for the evaluation of the Loss of two Channels of Instrument AC power (LCH13 – for the loss of Channels I1 and I3) initiating event was also revised to include the instrument inverter output breakers. Common cause failures among the output breakers were considered in the calculation of the frequency of this initiating event. The mean value of this frequency is used for the other Loss of two Channels of Instrument Power initiating events LCH12, LCH14, LCH 23, LCH24, and LCH34.

3. Event Sequence Modeling and Quantification

The PRA model used in this analysis (DC03MIC) is based on the latest interim model DC03MRAI.

The Top Event ICC is located in the event tree MECHSP immediately before Top Event I1. Logic rules were defined in the event tree MECHSP for the split fractions of top event ICC. In addition, the impact of the different state of top event ICC on Top Event I1 (Instrument AC Channel I), Top Event I2 (Instrument AC Channel II), Top Event I3 (Instrument AC Channel III), and Top Event I4 (Instrument AC Channel IV) were also modeled via split fraction logic rules.

Loss of Two Channels of Instrument AC Power Initiating Event	**Conditional Probability given one Channel is removed from service**
LCH14, 24, 34, 12 ,13	6.60E-05

All the Unit 1 initiating events were quantified using the updated event sequence model and the results of the CDF and the LERF for the various types/groups of initiating events are shown in the table below. These results are referred to as the base case result:

Initiator type	**CDF per year**	**LERF per year**
Internal Events	1.13E-05	1.65E-06
Seismic Events	2.62E-05	3.67E-06
Internal Fire Events	1.52E-05	1.11E-07
Internal Flooding Events	7.91E-06	1.86E-07
Total (Base Case)	**6.06E-05**	**5.62E-06**

4. Risk Evaluation for the Proposed IY-14 Inverter Output Breaker (52-14B2) Replacement

The proposed replacement of IY-14 Inverter Output Breaker 52-14B2 requires the Instrument AC Channel IV (Top Event I4) to be taken out-of-service. Because the exigent LAR to support this replacement will be applicable to any of the instrument AC channels, the instrument channel with the highest risk impact was used to evaluate the acceptability of the change. To model the risk impact of this activity, the following steps were taken:

- Generate the DCPP PRA model DC03MRAK by "cloning" it from the DC03MIC Model.
- Set the Top Event I4 in the event tree MECHSP of the DC03MRAK model to a guaranteed failure status via logic rule. This effectively removes Instrument AC Channel IV from service.
- Given the removal of the affected channel of Instrument AC power (Channel IV – Top Event I4) for replacing Output Breaker 52-14B2, loss of any of the other channels of Instrument AC power (Channel I, II, or III) would lead to a reactor trip. In addition, the LCO allowed outage time for the inoperable channel of Instrument AC power (for Output Breaker 52-14B2 replacement) is assumed to be 24 hours for this analysis.
- The following Loss of one Channel of Instrument AC Power initiating events given the removal of Instrument AC power Channel IV from service are considered in this analysis;
  - LCH14
  - LCH24
  - LCH34

Since the Loss of two Channels of Instrument AC Power initiating event is based on Top Event II (loss of Instrument AC Channels I and III), removal of one channel of Instrument AC power from service is done in this top event by setting the components associated with Instrument AC Channel I to a failed/unavailable state and extending the AOT to 24 hours. The frequency values for these initiating events are then quantified.

- Requantify event sequence/tree model for all the initiating events to determine the increase in the CDF and LERF
- Calculate the increase (compared to the baseline values) in CDF and LERF when one Instrument AC power channel is removed from service
- Calculate the Conditional Core Damage Probability (CCDP) and Conditional Large Early Release Probability (CLERP) for the above two time periods

This process was repeated for each instrument AC channel by making the logic changes shown in the table below. Each model referenced in the table is based on a clone of the IY14 application model DC03MRAK with the I4=F logic impact removed.

Channel	Model	Logic Change
IY11	DC03MRA1	I1=F Inserted at beginning of I1 Rules
IY12	DC03MRA2	I2=F Inserted at beginning of I1 Rules
IY13	DC03MRA3	I3=F Inserted at beginning of I1 Rules

The resulting conditional loss of the remaining Instrument AC Power Channel (given one Instrument AC Power Channel (IV) is removed from service) is provided in the table below:

Loss of Two Channels of Instrument AC Power Initiating Event	Conditional Probability given one Channel is removed from service
LCH14	4.213E-05
LCH24	4.213E-05
LCH34	4.213E-05

The results of the requantification of the event sequence model (DC03MRAK) for the initiating events are shown in the table below:

Group	Description	Base Case	IY11	IY12	IY13	IY14
ICDF	CDF for all Internal IEs	1.13E-05	2.47E-05	5.24E-05	5.24E-05	2.25E-05
ILERF	Large Early Containment Failure and Bypass	1.65E-06	5.41E-06	3.10E-06	3.10E-06	5.22E-06
OFCDF	Original Fire CDF	1.52E-05	1.53E-05	1.53E-05	1.53E-05	1.53E-05
OFLERF	Original Fire LERF	1.11E-07	1.12E-07	1.14E-07	1.14E-07	1.12E-07
SCDF	Seismic CDF	2.62E-05	2.87E-05	2.62E-05	2.62E-05	2.89E-05
SLERF	Large Early Containment Failure and Bypass (Seismic)	3.67E-06	4.03E-06	3.67E-06	3.67E-06	4.05E-06
U1CDFIC	Unit 1 CDF for Internal, Seismic, Flooding, Fire	6.06E-05	7.71E-05	1.03E-04	**1.04E-04**	7.51E-05
U1FLCDF	Unit 1 Internal Flooding CDF	7.91E-06	8.47E-06	9.05E-06	1.01E-05	8.44E-06
U1FLLERF	Unit 1 Internal Flooding LERF	1.86E-07	2.11E-07	2.13E-07	2.46E-07	2.09E-07
U1LERFIC	Unit 1 LERF for Internal, Seismic, Flooding, Fire	5.62E-06	**9.77E-06**	7.10E-06	7.13E-06	9.59E-06

The highlighted results in the table above show the highest results for CDF and LERF. The largest increase in CDF occurs for the IY13 channel. One of the key contributions to CDF for the IY13 case is from small loss-of-coolant accident (LOCA) (including Seal LOCAs and power operated relief valve (PORV) LOCAs) scenarios where the loss of the IY13 channel results in a failure to open of the Residual Heat Removal (RHR) Train B Miniflow Valve (FCV-641B) coupled with a random failure of RHR Train A.

For LERF, the IY11 case results in the highest risk. The key contributor to LERF for this model configuration is from SG tube rupture scenarios where one train of SSPS fails due to the loss of IY11 coupled with a random failure of SSPS Train B. The operator action to perform manual SI actuation then fails and, due to complete dependency between the manual SI action and the operator diagnosis of a tube rupture, core damage occurs.

The highest CDF metric that will determine the bounding CT is from the IY13 case, and the highest LERF metric that will determine the bounding CT is from the IY11 case.

<u>Risk Metrics</u>

ΔCDF_{AVE} = change in the average CDF due to the unavailability of Instrument AC power Channel IV. This risk metric is used to compare against the criteria of RG 1.174, Revision 2, to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, CDF_{BASE}.

$\Delta LERF_{AVE}$ = change in the annual average LERF due to the unavailability of Instrumental AC power Channel IV. Similar to ΔCDF_{AVE}, RG 1.174 criteria were also applied to judge the significance of changes in this risk metric.

ICCDP = incremental conditional core damage probability with Instrumental AC Power Channel IV out-of-service for an interval of time equal to the proposed CT (i.e., 24 hours). This risk metric is used as suggested in RG 1.177 to determine whether a proposed CT has an acceptable risk impact.

ICLERP = incremental conditional large early release probability with Instrumental AC power Channel IV out-of-service for an interval of time equal to the proposed CT (i.e., 24 hours). Similar to incremental conditional core damage probability (*ICCDP),* RG 1.177 criteria were also applied to judge the significance of changes in this risk metric.

The above risk metrics were quantified using the equations provided below.

Change in CDF/LERF

The equation for the change in the annual average CDF is provided below:

$$\Delta CDF_{AVE} = F_{OOS} \times (CDF_{OOS} - CDF_{BASE}) = \left(\frac{T_{OOS}}{T_{YEAR}}\right) \times (CDF_{OOS} - CDF_{BASE}) \quad \text{(Equation 1)}$$

where the following definitions apply:

$F_{OOS} = \left(\frac{T_{OOS}}{T_{YEAR}}\right)$ = The annualized fraction of time that Instrument AC Power Channel IV is expected to be unavailable as a result of the increased CT

T_{OOS} = Additional time per year that Instrument AC Power Channel IV is expected to be unavailable as a result of the increased CT.

CDF_{OOS} = CDF evaluated from the PRA model with Instrument AC Power Channel IV unavailable.

CDF_{BASE} = Baseline annual average CDF with average unavailability of AC Power Channel IV consistent with the current TS AOT (2 hours). This is the CDF result of the current baseline DCPP PRA model Unit 1.

A similar approach was used to evaluate the change in the average LERF ($\Delta LERF_{AVE}$).

$$\Delta LERF_{AVE} = F_{OOS} \times (LERF_{OOS} - LERF_{BASE}) = \left(\frac{T_{OOS}}{T_{YEAR}}\right) \times (LERF_{OOS} - LERF_{BASE}) \quad \text{(Equation 2)}$$

where the following definitions were applied.

$LERF_{OOS}$ = LERF evaluated from the PRA model for Unit 1 with Instrument AC Power Channel IV unavailable.

$LERF_{BASE}$ = Baseline annual average LERF with average unavailability of Instrument AC Power Channel IV consistent with the current TS AOT (2 hours). This is the LERF result of the current baseline DCPP PRA for Unit 1.

Incremental Conditional Probabilities

The ICCDP and incremental conditional large early release probability (ICLERP) are computed using their definitions in RG 1.177. The ICCDP values are dimensionless probabilities used to evaluate the incremental probability of a core damage event over a period of time equal to the extended CT. This should not be confused with the evaluation of ΔCDF_{AVE}, in which the CDF is based on expected unavailability. However, the endstate frequencies used to calculate ICCDP/ICLERP are the same as those used to calculate the change in CDF/LERF as described in the previous section.

The ICCDP is calculated by multiplying the change in CDF by the full CT (T_{CT}) requested. Therefore,

$$\mathrm{ICCDP} = (\mathrm{CDF}_{OOS} - \mathrm{CDF}_{BASE}) \times \mathrm{T}_{CT} \qquad \text{(Equation 3)}$$

Similarly, ICLERP is defined as follows.

$$ICLERP = (LERF_{OOS} - LERF_{BASE}) \times T_{CT} \qquad \text{(Equation 4)}$$

where T_{CT} is the proposed CT, in year (i.e., 24 hours or 2.740E-03 year)

The applicable methodology/criteria for assessing the risk associated with extending the CT for TS systems/components is provided in RG 1.177.

Assumptions/Assertions

1. To estimate the risk impact to the change in average CDF as a result of the change in the Complete Time as described in Reg. Guide 1.177, Revision 1, the current annual out-of-service outage duration for one channel of Instrument AC power is conservatively assumed to be 2 hours for Modes 1 through 4. This is used in the T_{OOS} time and is used to estimate the possible additional risk for having longer outage times for the Vital Instrument Power channels under the new proposed CT. A Maintenance Rule Unavailability review for Modes 1 – 4 showed an average outage out-of-service time much less than the assumed 2 hours.

2. The extended TS CT of 24 hours for TS 3.8.9 Condition B could be used for the associated output breaker replacement for any of the IY output breakers. This analysis is bounding for any of the four channels on Unit 1 and is also

applicable to Unit 2. Note that for Unit 2, there are only three susceptible IY output breakers, therefore the common cause contributions would be less and the risk impact would be bounded by the Unit 1 analysis.

3. The average maintenance PRA model used in this analysis (DC03MIC) is based on the latest interim model (DC03MRAI).
4. All IY output breakers that are of the electronic style trip device type are assumed to be susceptible to the trip mechanism of IY-14, and common cause is modeled for those breakers.
5. This risk assessment is for the maintenance work of replacing the IY output breakers with an electronic style trip device, with a nonelectronic style trip device that is not susceptible to false actuation, which could spuriously cause the breaker to open.

<u>Input</u>

Base case Core Damage Frequency, CDF_{BASE} = 6.06E-05 per year
Base case Large Early Release Frequency, $LERF_{BASE}$ = 5.62E-06 per year

One Instrument AC Power Channel III Unavailable, CDF_{OOS} = 1.04E-04 per year
One Instrument AC Power Channel IV Unavailable, $LERF_{OOS}$ = 9.77E-06 per year
One Instrument AC Power Channel IV OOS Duration, T_{OOS} = 2 + 24 = 26 hours

Proposed CT for output breaker replacement, T_{CT} = 24 hours
Availability factor for DCPP Unit 1 = 0.9

Number of hours in one reactor year for DCPP Unit 1, T_{YEAR} = 0.9 * 8760 = 7884 hours

Acceptance Criteria

The acceptance guidelines for TS changes are provided in Sections 2.4 and 2.5 of RG 1.174 and for CT changes in Section 2.4 of RG 1.177. The impact of the proposed change is considered very small and low risk if the estimated risk metric values are less than those listed below.

Risk Metric	**Acceptance Criteria**
ΔCDF_{AVE}	1.0 E-06 per reactor year
$\Delta LERF_{AVE}$	1.0 E-07 per reactor year
$ICCDP$	1.0 E-06
$ICLERP$	1.0 E-07

Calculation

1) Calculate the change in CDF and LERF using the component models.

$\Delta CDF = CDF_{OOS} - CDF_{BASE} = 4.34E\text{-}05$ per year

$\Delta LERF = LERF_{OOS} - LERF_{BASE} = 4.15E\text{-}06$ per year

2) Calculate the RG 1.174 and 1.177 Risk Metrics

Change in CDF/LERF

Using Equations 1 and 2, the changes in the annual average CDF and LERF are calculated as follows:

$\Delta CDF_{AVG} = (T_{OOS}/T_{YEAR}) * (CDF_{OOS} - CDF_{BASE})$

$= (26/7884) * (1.04E\text{-}04 - 6.06E\text{-}05)$

= 1.43E-07 per reactor year

Similarly, by substituting $\Delta LERF$ in place of ΔCDF,

$\Delta LERF_{AVG} = (T_{OOS}/T_{YEAR}) * (LERF_{OOS} - LERF_{BASE})$

$= (26/7884) * (9.77E\text{-}06 - 5.62E\text{-}06)$

= 1.37E-08 per reactor year

<u>Incremental Conditional Core Damage Probabilities (ICCDPs)</u>

The ICPs (ICCDP and ICLERP) are calculated based on Equations 3 and 4 with an additional parameter, T_F, which is introduced to account for the difference in the duration of applicable operating modes. The value of T_F is 24 hours.

Incremental conditional core damage probability with Instrumental AC power Channel IV out-of-service for an interval of time equal to the proposed CT (i.e., 24 hours or 2.74E-03 year), ICCDP = $(CDF_{OOS} - CDF_{BASE}) * T_{CT}$

= (1.04E-04 - 6.06E-05) * 2.74E-03

= **1.19E-07**

Incremental conditional large early release probability with Instrumental AC power Channel IV out-of-service for an interval of time equal to the proposed CT (i.e., 24 hours or 2.74E-03 year), ICLERP = $(LERF_{OOS} - LERF_{BASE}) * T_{CT}$

= (9.77E-06 - 5.62E-06) * 2.74E-03

= **1.14E-08**

<u>Results And Conclusion</u>

The table below lists the results of the risk metrics along with their RG 1.174 and RG 1.177 acceptance criteria.

Risk Metric	Acceptance Criteria	IY-13 OOS for CDF and IY11 OOS for LERF
ΔCDF_{AVG}*	1.0 E-06	**1.43E-07**
$\Delta LERF_{AVG}$ *	1.0 E-07	**1.37E-08**
ICCDP	1.0 E-06	**1.19E-07**
ICLERP	1.0 E-07	**1.14E-08**

Note:* The unit is per reactor year

Based on the results of the risk metrics calculated above the impact of the proposed change in CT to 24 hours of any one Instrument AC Channel is considered low risk as the risk metric values meet the acceptance criteria for TS changes provided in Sections 2.4 and 2.5 of RG 1.174 and for AOT changes in Section 2.4 of RG 1.177.

The bounding CDF metric calculated above for removing Instrument AC Power Channel III (IY-13) from service and bounding LERF metric from AC Power Channel I (IY-11) are also applicable to the cases where AC Power Channel II (IY-12), or Channel IV (IY-14) is removed from service for the replacement of the associated output breaker(s).

In the calculation of the risk metrics for the removal of one Instrument AC Power Channel from service as discussed above, the following has an impact on the results:

- Modeling of common cause failure of the output breakers
- Conditional failure probability an Instrument AC Power Channel given another Instrument AC Power Channel has been removed from service

Contributions from the common cause failures of the output breakers is highest when it is assumed either Instrument AC Power Channel II (IY-12) or IV (IY-14) is removed from service since the number of breakers involved in common cause failures in the remaining three Instrument AC Power Channels is the most [a total of 5 – two each from Channels I (IY-11) and III (IY-13), and one from either Channel II (IY-12) or IV (IY-14)]. Therefore, the results of the modeling of the common cause failures of the output breakers as discussed above are directly applicable to the case in which Instrument AC Power Channel II (IY-12) is removed from service, and the results will be conservative when applied to the cases in which either Instrument AC Power Channel I (IY-11) or Instrument AC Power Channel III (IY-13) is removed from service.

The conditional failure probability of an Instrument AC Power Channel given another Instrument AC Power Channel has been removed from service is based on the model for Instrument AC Power Channel III (IY-13) in the PRA model. This Instrument AC Power Channel has two output breakers – compared to only one output breaker for Instrument AC Power Channel II (IY-12) and Instrument AC Power Channel IV (IY-14). Instrument AC Power Channel I (IY-11) also has two output breakers. The other components (such as inverter, regulating transformer, etc.) are essentially the same in all the Instrument AC Power Channels. Therefore, this conditional failure probability value is exact when used for the case of removing Instrument AC Power Channel II (IY-12) or Instrument AC Power Channel IV (IY-14) from service and is conservative when used for the case of removing Instrument AC Power Channel I (IY-11) or Instrument AC Power Channel III (IY-13) from service.

Additionally, it should be noted that Unit 2 only has three susceptible electronic style IY inverter 120 VAC output breakers currently installed, therefore the Unit 1 results above bound Unit 2.

<u>Tier 2: Avoidance of Risk-Significant Plant Configurations</u>

The objective of the second tier, which is applicable to CT extensions, is to provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when equipment is out-of-service. If risk-significant configurations do occur, then enhancements to TS or procedures, such as limiting unavailability of backup systems, increased surveillance frequencies, or upgrading procedures or training, can be made that avoid, limit, or lessen the importance of these configurations.

Adhering to the current TS requirements and procedures will prevent these types of risk-significant configurations from occurring. Therefore, there is reasonable assurance that risk-significant plant equipment configurations will not occur when the component is OOS using the proposed TS changes. No other changes to the TS or procedures, or any compensatory actions, are required as the result of this proposed LAR.

Because the dominant initiator in this analysis is a reactor trip, the potential configurations that should be avoided while the 120 VAC vital bus subsystem is out-of-service per TS 3.8.9 include those that are important to mitigation for a reactor trip.

As such, activities that could reduce the unavailability/reliability of following systems/components should be avoided:

- the Auxiliary Feedwater System
- any of the other three 120VAC vital buses
- the redundant SSPS Train

Tier 3: Risk-Informed Configuration Risk Management

The objective of the third tier is to ensure that the risk impact of out-of-service equipment is evaluated prior to performing any maintenance activity. As stated in RG 1.177, "a viable program would be one that is able to uncover risk-significant plant equipment outage configurations as they evolve during real-time, normal plant operation." The third-tier requirement is an extension of the second-tier requirement, but addresses the limitation of not being able to identify all possible risk-significant plant configurations in the second-tier evaluation.

PG&E has developed a process for online risk assessment and management. Following the process and procedures ensures that the risk impact of equipment unavailability is appropriately evaluated prior to performing any maintenance activity or following an equipment failure or other internal or external event that impacts risk. PG&E Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management," provides guidance for managing safety function, probabilistic, and plant trip risks as required by 10 CFR 50.65(a)(4) of the Maintenance Rule. The procedure addresses risk management practices in the maintenance planning phase and maintenance execution (real time) phase for Modes 1 (Power Operation) through 4 (Hot Shutdown). Appropriate consideration is given to equipment unavailability, operational activities such as testing, and weather conditions.

In general, risk from performing maintenance on-line is minimized by:

- Performing only those preventive and corrective maintenance items on-line required to maintain the reliability of structures, systems, and components (SSCs).
- Minimizing cumulative unavailability of safety-related and risk-significant SSCs by limiting the number of at-power maintenance outage windows per cycle per train/component.
- Minimizing the total number of SSCs out-of-service at the same time.
- Minimizing the risk of initiating plant transients (trips) that could challenge safety systems by implementing compensatory measures.
- Avoiding higher risk combinations of out-of-service SSCs using PRA insights.
- Maintaining defense-in-depth by avoiding combinations of out-of-service SSCs that are related to similar safety functions or that affect multiple safety functions.
- Scheduling in train/bus windows to avoid removing equipment from different trains simultaneously.

In general, risk is managed by:

- Evaluating plant trip risk activities or conditions and mitigating them by taking appropriate compensatory measures and/or ensuring defense-in-depth of safety systems that are challenged by a plant trip.
- Evaluating and controlling risk based on probabilistic and key safety function defense-in-depth evaluations.
- Implementing compensatory measures and requirements for management authorization or notification for certain “high-risk” configurations.

Actions are taken and appropriate attention is given to configurations and situations commensurate with the level of risk as evaluated using AD7.DC6. This occurs both during planning and real time (execution) phases.

For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed and documented per AD7.DC6 prior to scheduled work. Consideration is given to plant and external conditions, the number of activities being performed concurrently, the potential for plant trips, and the availability of redundant trains.

Risk is evaluated, managed and documented for all activities or conditions based on the current plant state:

- Before any planned or emergent maintenance is to be performed.
- As soon as possible when an emergent plant condition is discovered.
- As soon as possible when an external or internal event or condition is recognized.

Compensatory measures are implemented as necessary and if the risk assessment reveals unacceptable risk, a course of action is determined to restore degraded or failed safety functions and reduce the probabilistic risk.

Summary/Conclusion

Based on the above, the change to the TS 3.8.9 Condition B CT to 24 hours is acceptable.

4. REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

RG 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated May 2011, and RG 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," dated May 2011, provide specific guidance and acceptance criteria for assessing the nature and impact of licensing-basis changes, including proposed permanent TS changes in AOTs or CTs by considering engineering issues and applying risk insights. In addition, Chapter 16.1, "Risk-Informed Decision Making: Technical Specifications," of the Nuclear Regulatory Commission (NRC, the Commission) Standard Review Plan (SRP), NUREG-0800, describes acceptable approaches and guidelines in reviewing proposed TS modifications, including CT changes as part of risk-informed decision making.

The Maintenance Rule, 10 CFR 50.65(a)(4), requires licensees to perform assessments before conducting maintenance activities on SSCs that are covered by the Maintenance Rule, and to manage any increase in risk that may result from the proposed activities. RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated May 2012, provides guidance on implementing the provisions of 10 CFR 50.65(a)(4). RG 1.174, Section 2.3, Element 3, "Define Implementation and Monitoring Program," states that monitoring that is in conformance with the Maintenance Rule can be used to satisfy Element 3 when the monitoring performed under the Maintenance Rule is sufficient for the SSCs affected by the risk-informed application.

General Design Criterion (GDC) 17 (1971), "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of SSCs that are important to safety. The onsite power system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to supply power to the onsite electric distribution system by two physically independent circuits that are 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. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

The DCPP Units 1 and 2 designs conform to Criterion 17. The Class 1E 120 VAC system is required to have sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

GDC-18 (1971), "Inspection and testing of electric power systems," requires that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing.

The DCPP Units 1 and 2 designs conform to Criterion 18. The Class 1E portion of the 120 VAC system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical. Safety Guide 6, March 1971 – "Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems." The Class 1E portion of the 120 VAC system is designed such that electrically powered loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed.

The TS for DCPP, Units 1 and 2, currently require that an instrument bus must be reenergized within 2 hours (TS 3.8.9, "Distribution Systems-Operating") and an inoperable inverter must be restored within a CT of 24 hours (TS 3.8.7). The proposed license amendment would change the CT for restoring a 120 VAC vital bus subsystem from 2 hours to 24 hours, consistent with the CT for an inoperable inverter.

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

4.2 Precedent

On November 19, 2003, the NRC approved amendments 135/135 for Byron Station and amendments 129/129 for Braidwood Station to increase the CT for an inoperable inverter from 24 hours to 7 days.
While the TS being revised is different from the proposed TS, these amendments were also risk-informed CT changes for an electrical system.

4.3 Significant Hazards Consideration

PG&E has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The requested change does not physically alter any plant structures, systems, or components, and does not affect or create new accident initiators or precursors. The completion time (CT) to perform a required action is not an accident initiator; therefore, there is no effect on the probability of accidents previously evaluated.

   An alternating current (AC) source is required to mitigate the consequences of accidents previously evaluated in the Final Safety Analysis Report Update. The requested change to allow one 120 Volts Alternating Current (VAC) vital bus subsystem to be inoperable for up to 24 hours does not increase the consequences of those accidents since an additional redundant train is available.

   Additionally, the redundant 120 VAC vital bus subsystem remains operable and capable of performing its required function. The requested change does not affect the types or amounts of radionuclides released following an accident, or the initiation and duration of their release.

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

2. Does the proposed change create the possibility of a new or different accident from any accident previously evaluated?

Response: No.

The proposed amendment will not change the design function or operation of the structures, systems, and components (SSCs) involved, nor will it affect the SSCs' operation or their ability to perform their design function. The proposed change will not create the possibility of a new or different kind of accident due to credible new failure mechanisms, malfunctions, or accident initiators not considered in the design and licensing bases.

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

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

Response: No.

The proposed amendment does not involve a significant reduction in a margin of safety. There will always be at least one full train of Engineered Safety Feature (ESF) equipment available such that the Emergency Core Cooling System, Auxiliary Feedwater system, and containment heat removal system will be able to ensure that adequate core cooling, Reactor Coolant System (RCS) integrity and containment integrity are maintained for all Design Basis Accidents (DBA).

There will be no adverse impact on any ESF equipment function required for DBA mitigation such that no safety limit or fission product barrier design basis limit for the fuel, RCS, or containment described in the Updated Final Safety Analysis Report (UFSAR) will be exceeded or altered.

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

Based on the above evaluation, PG&E concludes that the proposed change does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

4.4 Conclusions

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

5. ENVIRONMENTAL CONSIDERATION

PG&E has evaluated the proposed amendment and has determined that the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation 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

None.

Technical Specification Page (Markups)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems-Operating

LCO 3.8.9 — The required Class 1E AC, DC, and 120 VAC vital bus electrical power distribution subsystems shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
B. One 120 VAC vital bus subsystem inoperable.	B.1	Restore 120 VAC vital bus subsystem to OPERABLE status.	~~2~~ 24 hours
C. One DC electrical power distribution subsystem inoperable.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. Two required Class 1E AC, DC, or 120 VAC vital buses with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

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3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems-Operating

LCO 3.8.9 The required Class 1E AC, DC, and 120 VAC vital bus electrical power distribution subsystems shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
B. One 120 VAC vital bus subsystem inoperable.	B.1 Restore 120 VAC vital bus subsystem to OPERABLE status.	24 hours
C. One DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. Two required Class 1E AC, DC, or 120 VAC vital buses with inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

Technical Specification Bases Page (Markups)
(For information only)

BASES

ACTIONS

B.1 (continued)

constant voltage transformer. The required AC vital bus subsystems must then be re-powered by restoring it's associated inverter to OPERABLE status within 24 hours under LCO 3.8.7. ACTION A.1.

Condition B represents one 120 VAC vital bus without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected 120 VAC vital bus subsystem.

~~This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate 120 VAC power.~~The 24 hour limit is a risk informed completion time. The time is consistent with the time allowed for an inoperable inverter under LCO 3.8.7, and provides sufficient time to complete repairs or component replacement. Taking exception to LCO 3.0.2 for components without adequate vital 120 VAC power, that would have the Required Action Completion Times shorter than 24 hours if declared inoperable, is acceptable because of:

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

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital 120 VAC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected subsystem; and

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

d. Operations procedures are in place to address plant conditions including plant trips or a safety injection if a component of the other subsystem should fail.

The 24 hour Completion Time takes into account the importance to safety of restoring the 120 VAC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE 120 VAC vital buses, and the low probability of a DBA occurring during this period.

(continued)