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January 26, 2017

PG&E Letter DCL-17-009

Mr. Kriss M. Kennedy
Regional Administrator, Region IV
U.S. NRC Region IV
1600 East Lamar Boulevard
Arlington, Texas 76011-4511

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Power Plant Units 1 and 2
<u>Appeal of Final Significance Determination Process Finding; EA-16-168</u>

References:
1. NRC Letter, "Diablo Canyon Power Plant – NRC Inspection Report 05000275/2016010 and 05000323/2016010; Preliminary White Finding," dated October 3, 2016 (EA-16-168) (ADAMS Accession No. ML16277A340)
2. NRC Letter, "Diablo Canyon Power Plant - Final Significance Determination of a White Finding, Notice of Violation, and Follow-Up Assessment Letter; NRC Inspection Report 05000275/2016010 and 05000323/2016010," dated December 28, 2016 (EA-16-168) (ADAMS Accession No. ML16363A429)
3. NRC Letter, "NRC Response to Questions Involving Diablo Canyon Power Plant – Final Significance Determination of a White Finding; NRC Inspection Report 05000275/2016010 and 05000323/2016010," dated January 17, 2017 (ADAMS Accession No. ML17017A437)
4. PG&E Letter DCL-17-010 to NRC, "Reply to a Notice of Violation; EA-16-168," dated January 26, 2017

Dear Mr. Kennedy:

Pacific Gas and Electric Company (PG&E) has reviewed the Final Significance Determination (FSD), EA-16-168, dated December 28, 2016 (Reference 2), in which the NRC concluded that an inspection finding should be characterized as having low to moderate safety significance (*i.e.*, White) and that escalated enforcement against PG&E is warranted. PG&E does not dispute NRC's characterization of the matter as

a violation. We have taken appropriate steps to correct the procedure and to ensure that other valves were not similarly affected (Reference 4).

PG&E and the NRC share a mutual interest in protecting public health and safety and in ensuring a basis for accurate assessment of regulatory violations. PG&E acknowledges we did not describe or assess the procedural operator actions prior to the Preliminary Significance Determination (PSD) (Reference 1). As a result, PG&E presented a large amount of new information at the Regulatory Conference. PG&E appreciates the NRC's efforts to understand and promptly assess this new information in the FSD. PG&E also appreciates the NRC's efforts to promote transparency and openness by clarifying the FSD inputs and timelines in response to questions by PG&E (Reference 3). The NRC has demonstrated a level of professionalism and courtesy throughout this process that has been consistent with the NRC's Principles of Good Regulation and the agency's organizational values.

PG&E received a Preliminary White Finding from the NRC in Inspection Report 05000275/2016010 and 05000323/2016010, dated October 3, 2016 (Reference 1). The finding and PSD were associated with a failure to provide adequate maintenance instructions for ensuring that external limit switches on motor-operated valves are operated within the vendor established overtravel settings.

At PG&E's request, a Regulatory Conference was held on November 15, 2016. PG&E presented information, prior to, during, and following the Regulatory Conference concerning the ability to recover from the condition associated with the finding through a series of plant actions. The information showed that the finding should be characterized as having very low safety significance (*i.e.*, Green).

PG&E subsequently received the FSD (Reference 2). The FSD concludes that the inspection finding should be characterized as having low to moderate safety significance (*i.e.*, White). The letter provides 30 calendar days from the date of that letter to appeal the NRC's significance determination for this finding.

PG&E has performed a thorough review of the NRC's assessment and considered both the prerequisites and the limitations as described in NRC Inspection Manual Chapter (IMC) 0609, Attachment 0609.02, "Process for Appealing NRC Characterization of Inspection Findings (Significance Determination Process (SDP) Appeal Process)," Sections 0609.02-02 and 0609.02-03. After carefully considering the available information, PG&E respectfully appeals the NRC's characterization of the FSD conclusion as White.

A summary of the FSD appeal, including the basis for meeting the prerequisites and limitations in IMC 0609 is presented in Enclosure 1. Enclosure 2 to this letter provides the detailed bases for PG&E's appeal. As shown in the enclosures,

consideration of the best available information for this performance deficiency results in an increase in core damage frequency of less than 6E-07 per year. Based on these results, the finding appropriately should be characterized as having very low safety significance (*i.e.*, Green).

PG&E appreciates the NRC's fair and independent consideration of the issues raised in this appeal in accordance with established processes. Should the NRC have questions regarding the appeal, we remain available to continue our professional dialogue in order to achieve a common understanding of the facts and significance of this finding. We look forward to reviewing the results of NRC's objective assessment of the issues raised in this appeal.

PG&E makes no new or revised regulatory commitments (as defined by NEI 99-04) in this letter.

If there are any questions concerning this matter, please contact
Mr. Hossein Hamzehee at (805) 545-4720.

Sincerely,

Edward D. Halpin
Senior Vice President Generation and Chief Nuclear Officer

mem6/4539/50886801
Enclosures
cc/enc: Paula Gerfen, Station Director
Jon A. Franke, Vice President Generation Technical Services
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Summary of Basis for Appeal of Final Significance Determination

Inspection Manual Chapter (IMC) 0609, Attachment 0609.02, "Process for Appealing NRC Characterization of Inspection Findings (SDP Appeal Process)," dated June 8, 2011, defines the process by which a licensee may appeal the NRC Staff's final determination of the significance of an NRC inspection finding. Section 0609.02-02 requires that four prerequisites be met for appeal. In this case the prerequisites have been met in that:

a. The NRC characterized the inspection finding as preliminarily greater than Green in NRC Inspection Report 05000275/2016010 and 05000323/2016010, dated October 3, 2016. (Reference 1)
b. The Inspection Report served as the preliminary significance determination (PSD) letter and included an opportunity for PG&E to present additional information.
c. PG&E opted for a Regulatory Conference to provide additional information which was held on November 15, 2016. PG&E also provided additional information in writing to the NRC Staff that was reviewed and dispositioned by the Staff.
d. The NRC Staff sent PG&E its Final Significance Determination (FSD), EA-16-168, in a letter dated December 28, 2016. (Reference 2)

Section 0609.02-03, "Limitations," states, in part, that once the prerequisites have been met, licensee appeals to reduce the significance of an inspection finding will be considered as having sufficient merit for review by the SDP Appeal Process only if the licensee's contention falls into one of three specified categories. These categories are summarized as follows:

a. The Staff's SDP was inconsistent with the applicable SDP guidance or lacked justification.
b. Actual (verifiable) plant hardware, procedures, or equipment configurations identified by the licensee to the NRC Staff at the Regulatory Conference or in writing prior to the Staff reaching a final significance determination, was not considered by the Staff.
c. A licensee submits new information which was not available at the time of the Regulatory Conference.

Based on its careful review, PG&E has identified six areas of the FSD that meet the criteria in Section 0609.02-03 Category a, Category b, or both. These six areas are hereinafter referred to as Bases 1-6, and the related categories for appeal are hereinafter termed Appeal Category A for category a. and Appeal Category B for category b.

A summary of the FSD appeal, including the basis for meeting the prerequisites and limitations in IMC 0609, is presented below. Enclosure 2 provides the detailed bases for PG&E's appeal. After consideration of the best available information for this performance deficiency, the finding appropriately should be characterized as having very low safety significance (*i.e.*, Green).

Basis	SDP Appeal Category	Summary	Updated ΔCDF
Basis No. 1: Use of Averaged NUREG-1829 Data	Category A – Use of averaged 25-year and 40-year loss-of-coolant accident (LOCA) frequency data from NUREG-1829 is not supported by guidance.	Section 3 of the Final Significance Determination (FSD) does not use 25-year LOCA frequency data in accordance with the NRC's Standardized Plant Analysis Risk (SPAR) model or NUREG-1829. At the Regulatory Conference, PG&E referenced the recommended 25-year LOCA frequency data from NUREG-1829. Use of the 25-year LOCA frequency data results in a risk reduction.	<1.2 E-06
Basis No. 2: Proceduralized Actions to Assess Time to Core Damage	Category B – The FSD assessed 2.8 hours for the time between 4% refueling water storage tank (RWST) level and core damage. This timeline does not consider implementation of actual plant procedures to makeup from the Volume Control Tank (VCT) to the Reactor Coolant System (RCS).	The FSD does not accurately credit the procedural requirements of Emergency Operating Procedure (EOP) ECA-1.1, Revision 22, in its evaluation of the time between cessation of Emergency Core Cooling System (ECCS) injection flow and the time peak core temperature exceeds 1800°F. PG&E provided a detailed timeline for implementing EOP ECA-1.1, Appendix W that shows 7.76 hours from cessation of ECCS injection until exceeding 1800°F. This is a significantly longer period of time than was considered in the FSD and extends the time available for implementing electrical and mechanical recovery actions by approximately 5 hours. Use of the longer time available results in a risk reduction.	Note 1
Note 1: Appeal Basis No. 2 does not directly affect ΔCDF, but supports accurate assessment of Time Available Performance Shaping Factor (PSF).			

Basis	SDP Appeal Category	Summary	Updated ΔCDF
Basis No. 3: Reference to Superseded Procedure When Assessing Operator Actions, Performance Shaping Factors, Timing of Recovery Actions, Sequence of Recovery Actions, and Dependency	Category B – The FSD references a superseded procedure and does not reflect actual plant procedures in effect during the period of interest. Category A – The dependency analysis used in the FSD was not performed in accordance with SPAR-H guidance.	The FSD does not account for actual plant procedures provided by PG&E. The FSD references superseded EOP E-1.3, Revision 15, when assessing operator actions, evaluating performance shaping factors, and developing a timeline and sequence for recovery actions. The FSD does not reflect the actual sequence of manual and electrical recovery actions in accordance with procedures. Based on plant staff roles and responsibilities, NRC's use of high dependency among recovery actions is inconsistent with the SPAR-H method. Use of current procedural information to assess strategies to increase the time available for recovery methods and evaluate the timing and sequence of recovery actions results in a risk reduction.	<7.5 E-07
Basis No. 4: Application of SPAR-H Guidance for the Mechanical Recovery Procedure PSF	Category A – SPAR-H Step-by-Step guidance, Section 3.5, "Procedures," directs the NRC to demonstrate that the procedure is a performance driver for opening the chamber guard cover as a prerequisite to evaluating the Procedure PSF quantitatively.	The FSD uses the Procedure PSF for opening the recirculation valve chamber guard without first assessing whether procedures are in fact a performance driver for the subject human factors engineering (HFE) as directed by SPAR-H Step-by-Step Guidance. The simplicity of the action to remove chamber closure bolting supports PG&E's conservative selection of an "available but poor" Procedure PSF. Use of the available but poor Procedure PSF results in a risk reduction.	<8E-07

Basis	SDP Appeal Category	Summary	Updated ΔCDF
Basis No. 5: Recovery Time Available for SLOCAs	Category A – The NRC changed the Time Available PSF from "extra" in the PSD to "nominal" in the FSD without separately accounting for SLOCA recovery timelines, as discussed at the Regulatory Conference.	At the Regulatory Conference, PG&E described the impact that evaluating the Small Break LOCA (SLOCA) recovery timeline would have on overall risk significance. There was no need, however, to prepare a separate analysis for SLOCAs because the NRC had used the "extra" Time Available PSF in the PSD (consistent with PG&E's initial assessment). The NRC changed this PSF to "nominal" in the FSD without providing PG&E an opportunity to respond. Had PG&E been given the opportunity to address the characterization of the electrical recovery time available PSF as "nominal," or had the NRC considered a SLOCA recovery timeline as noted by PG&E at the Regulatory Conference, the analysis would show that the "extra" Time Available PSF is appropriate for SLOCA recovery actions. Use of this PSF results in a risk reduction.	<1E-06

Basis	SDP Appeal Category	Summary	Updated ΔCDF
Basis No. 6: Use of a Range To Assess Overall Risk Significance	Category A – Using a range is inconsistent with SDP guidance, including IMC 0308, Attachment 3, and IMC 0609, Attachment 1. The FSD does not specify the result as a single mean value, or point estimate, based on the "best available information." Category B – The NRC's "upper range" of the ΔCDF in the FSD, which is the same as the ΔCDF in the PSD, does not account for actual plant hardware, procedures, and equipment configurations.	SDP guidance indicates that quantitative evaluations in the FSD should be based on a single value (*i.e.*, point estimate) that reflects the "best available information," supplemented, as necessary, by sensitivity evaluations. Use of a range, rather than a sensitivity evaluation as discussed in IMC 0609, Attachment 1, is inconsistent with SDP guidance. The "upper range" value in the FSD, which is simply the same value used in the PSD, does not reflect any changes associated with information that PG&E provided at the Regulatory Conference. If a range is used, the upper end of the range should be reassessed based on the information presented at the Regulatory Conference.	Note 2
Note 2: Appeal Basis No. 6 does not affect ΔCDF; however, it is instrumental in determining the overall significance of the violation.			

Final Significance Determination Appeal
Cornerstone: Mitigating Systems

Introduction

NRC inspectors identified a finding associated with an apparent violation of Technical Specification 5.4.1.a, "Procedures," for PG&E's failure to develop adequate maintenance procedures covering the installation, adjustment, and testing of Namco™ Model EA170 snap lock limit switches. Specifically, PG&E failed to provide site-specific instructions to establish and verify that the travel of external switches installed on motor-operated valves are within vendor-established criteria. Consequently, the limit switch actuator for Valve RHR-2-8700B, Residual Heat Removal (RHR) Pump 2-2 suction from the refueling water storage tank (RWST), was installed such that the limit switch operated repeatedly in an over-travel condition resulting in a sheared internal roll pin. The sheared roll pin rendered the external limit switch incapable of performing its intended function. The failure of the external limit switch on RHR-2-8700B was identified on May 16, 2016, during outage surveillance testing. The limit switch failure would have prevented operators from opening the Train B containment sump suction Valve SI-2-8982B from the Control Room in response to a Loss-of-Coolant Accident (LOCA).

Background

Plant Response to LOCA Event

LOCA events are characterized by reactor coolant leaking from the reactor coolant system (RCS), which lowers RCS inventory and pressure. In response to the loss of coolant and system pressure, a safety injection actuation signal starts the Emergency Core Cooling System (ECCS) pumps. These pumps take suction from the RWST and inject water into the RCS, which in turn leaks out of the break and into the containment where it collects in the containment recirculation sump. When the RWST level reaches 33 percent, the low pressure RHR pumps automatically shut down, and operators in the Control Room perform valve manipulations to swap the suction of the RHR pumps by closing the RHR pump RWST suction Valve RHR-2-8700B and opening containment sump suction Valve SI-2-8982B. The RHR pumps would then be restarted, taking suction from the containment sump and discharging back to the RCS and also providing suction for other higher pressure ECCS pumps. Valve SI-2-8982B is the first valve in the Train B flowpath leading from the containment sump. The inability to open Valve SI-2-8982B because of the failed RHR-2-8700B Valve external limit switch renders Train B of core cooling inoperable during the recirculation phase of a LOCA. The failure of Valve SI-2-8982B to open remotely on demand would be immediately recognized by Control Room operators performing the action when the Control Room valve position lights fail to change state.

PG&E has multiple options to recover and open Valve SI-2-8982B, including local mechanical operation, local electrical operation at the switchgear to bypass the failed limit switch, and installation of a jumper on the RHR-2-8700B Valve actuator to allow

opening of Valve SI-2-8982B from the Control Room. Use of the redundant 100 percent capacity Train A flowpath also would ensure core cooling if Valve SI-2-8982B failed to open.

If both recirculation sump suction Valves SI-2-8982A & B fail to open as was postulated by the NRC in its preliminary and final evaluation, operators transition to Emergency Operating Procedure (EOP) ECA-1.1, "Loss of Emergency Coolant Recirculation," and: (1) initiate continuous actions to restore ECCS recirculation from the containment sump; (2) initiate makeup water to the RWST to add inventory; (3) minimize safety injection pump (SIP)/centrifugal charging pump (CCP) injection to match the decay heat load and further preserve inventory; (4) depressurize the steam generators to cool down and depressurize the RCS thereby minimizing break flow; and (5) initiate makeup water to RCS from the volume control tank (VCT) through the normal charging line. The latter four actions do not prevent core damage, but rather increase the time available for the plant staff to respond and take action necessary to open Valve SI-2-8982B.

In accomplishing these operator actions, the Control Room would contact the Technical Support Center (TSC) to turn over responsibility for development and implementation of field actions to recover and open Valves SI-2-8982A and B. Control Room activities then would focus on delaying RWST depletion, filling the RWST, depressurizing the RCS, and adding inventory to the RCS from the VCT through the normal charging line in accordance with operating procedures. The additional maintenance and technical staffing in the TSC and Operational Support Center (OSC) available at this time would lead development and execution of recovery methods to open the valves, allowing the Control Room to focus on EOP ECA-1.1 actions that increase the time available to open Valve SI-2-8982B.

The Emergency Plan role of the TSC/OSC reduces the Control Room burden by determining and recommending corrective actions for plant equipment and staging, dispatching and coordinating trained personnel to perform those actions. This allows the Control Room to focus on EOP-directed actions that operators are trained to implement. A role of the OSC is to assure coordinated efforts between the TSC/OSC and the Control Room. In accomplishing this, the Control Room would notify the OSC when performing EOP-directed field actions (*i.e.*, non-Control Room actions) to assure that the OSC is tracking personnel in the field during the emergency. Operators also will confer with Radiation Protection to understand radiological conditions before performing EOP-directed field actions.

NRC Risk Evaluation

The NRC's preliminary significance determination (PSD) indicated that the performance deficiency affected the ability to enter the recirculation phase for all LOCAs, but that for two initiators, Small Break LOCA (SLOCA) and Medium Break LOCA (MLOCA), some credit should be given for the operators' ability to open Valve SI-2-8982B using methods external to the Control Room. The PSD concluded, based on the best information available to the NRC at that time, that the performance deficiency resulted in a change in core damage frequency (CDF) of 7.6E-06 per year.

Similar to the PSD, the Final Significance Determination (FSD) shows that the dominant core damage sequences involve Train A flowpath failures and the inability to recover Valve SI-2-8982B. The FSD risk evaluation result is a ΔCDF from the performance deficiency characterized as a range of values. In the FSD (Reference 2), the NRC concluded that its PSD ΔCDF result of 7.6E-06 per year represents the upper value in the range of ΔCDF associated with the performance deficiency. Based on the information provided by PG&E, NRC adjusted a number of assumptions used in the PSD. Specifically, NRC lowered the common cause alpha factors and adjusted several assumptions related to MLOCAs. The NRC also revised human error probability calculations used to determine the likelihood of recovering Valve SI-2-8982B functionality. These calculations predicted a 96.4 percent likelihood of success for recovering Valve SI-2-8982B. The NRC also made changes to inputs used in the PSD independent of information presented by PG&E. Using these revised inputs, the NRC concluded that the lower value in the range of the ΔCDF associated with the performance deficiency is 1.3E-06 per year. Using both the upper and lower values, the NRC characterized the finding as having low to moderate safety significance (White).

PG&E Risk Evaluation

PG&E, for its part, applied the NRC's current Standardized Plant Analysis Risk (SPAR) model to assess the ΔCDF based on actual plant hardware, procedures, and equipment configurations. PG&E developed a detailed timeline based on procedures in effect during the period of the performance deficiency. During the Regulatory Conference and in writing, PG&E presented a timeline that credits operator actions to reduce ECCS flowrate and to increase RWST inventory in accordance with Unit 2 EOP ECA-1.1, Revision 22 (effective January 5, 2016).[1] The sequence of events and timing are described in Table 1 (Attachment 1).[2] The timeline for parallel pursuit of the two TSC-directed local recovery actions (local electrical and mechanical recovery) is presented in Table 2 (Attachment 2).

Important differences between the timeline and sequence of events presented in the FSD and the timeline and sequence of events associated with application of the procedures in effect during the relevant period include the following:

- Control Room-directed EOP ECA-1.1, Appendix W, actions extend the available time for recovery of Valve SI-2-8982B by approximately 5 hours relative to the timeline considered in the FSD.

[1] Although Revision 21 was in effect during a portion of the Unit 2 cycle of interest, use of Revision 22 conservatively bounds the results of applying Revision 21.

[2] PG&E's Regulatory Conference presentation (Reference 3) of the event timeline covered a portion of the total sequence and time as developed in calculation Modular Accident Analysis Program (MAAP) 16-03, Revision 0 (Reference 4). PG&E provided MAAP 16-03, Revision 0, to the NRC on November 18, 2016. The complete timeline presented in Table 1,"Procedure Implementation and Response Timeline," and on Figure 1, "Event Timeline," reflects the analysis documented in Calculation MAAP 16-03, Revision 1 (Reference 5), which PG&E provided to the NRC on December 6, 2016. The NRC agreed to accept Revision 1 and consider it in the FSD.

- Control Room-directed EOP actions that extend the time available for recovery of Valve SI-2-8982B and TSC-directed local recovery actions proceed in parallel (not sequentially).

- Two TSC-directed local recovery actions (electrical and mechanical recovery) proceed in parallel (not sequentially)[3] using separate response teams.

- Consideration of Control Room-directed actions in parallel with TSC-directed local recovery actions results in approximately 14 hours available for recovery of Valve SI-2-8982B.

Based on the information presented by PG&E, the ΔCDF associated with the performance deficiency is less than 6E-07 per year. PG&E's detailed risk evaluation, using the NRC's SPAR model, indicates that the finding has very low safety significance. This determination reflects the availability of multiple options for recovering the functionality of Valve SI-2-8982B, the high likelihood of success of recovery, and the extended period of time in which to complete recovery efforts prior to the onset of core damage. Accordingly, PG&E concludes, based on the best available information and using the NRC's SPAR model, that the performance deficiency is appropriately characterized as Green.

Appeal Bases

As discussed in Enclosure 1, the Significance Determination Process (SDP) Appeal Process (IMC 0609.02) limits appeals to reduce the significance of violations to matters that fall into one or more of three defined categories. PG&E is basing its appeal on six issues that fall into one or more of the following two categories from the SDP Appeal Process, Section 0609.02-03:

Category A: The Staff's significance determination process was inconsistent with applicable SDP guidance or lacked justification.

Category B: Actual (verifiable) plant hardware, procedures, or equipment configurations, identified by the licensee to the NRC at the Regulatory Conference or in writing prior to the FSD, was not considered by the Staff.

In accordance with IMC 0609.02, PG&E appeals the FSD conclusion that the performance deficiency has low to moderate safety significance (*i.e.*, a White Finding) based on the following areas:

Basis No. 1: Use of Averaged NUREG-1829 Data.

Basis No. 2: Proceduralized Actions to Assess Time to Core Damage.

[3] Only the electrical and jumper recovery methods would credibly be pursued in sequential manner.

<u>Basis No. 3</u>: Reference to Superseded Procedure When Assessing Operator Actions, Performance Shaping Factors, Timing of Recovery Actions, Sequence of Recovery Actions, and Dependency.

<u>Basis No. 4</u>: Application of SPAR-H Guidance for the Mechanical Recovery Procedure PSF.

<u>Basis No. 5</u>: Recovery Time Available for SLOCAs.

<u>Basis No. 6</u>: Use of a Range To Assess Overall Risk Significance.

Below, PG&E provides the detailed basis for its appeal, including reference to one or more appropriate appeal categories for each basis.

<u>Basis No. 1</u>: Use of Averaged NUREG-1829 Data

<u>Summary</u>: Section 3 of the FSD does not use 25-year LOCA frequency data in accordance with the NRC's SPAR model or NUREG-1829. At the Regulatory Conference, PG&E referenced the recommended 25-year LOCA frequency data from NUREG-1829. Use of the 25-year LOCA frequency data results in a risk reduction greater than 1.5E-07 per year.

Background

The PSD calculated LOCA frequencies for the 2 to 3.5 inch and for the 3.5 to 6 inch break range using a linear method. PG&E provided information at the Regulatory Conference demonstrating that the calculation of LOCA frequencies should be based on logarithmic interpolation of 25-year fleet average data from NUREG-1829 (Reference 8). This same data and method of interpolation was used to develop the LOCA frequencies used in the NRC's SPAR model.

In Section 3 of the FSD, the NRC agrees that application of NUREG-1829 data is appropriate. However, the FSD applies a log-linear interpolation method to average the 25-year and 40-year LOCA frequencies from NUREG-1829 when calculating the LOCA frequencies. The FSD analysis then uses the average of 25-year and 40-year LOCA frequencies to conclude that the frequency for LOCAs between 4.5 to 6 inches is 5.21E-06 per year. The NRC also indicated that it had recalculated the small and large LOCA frequencies using averaged LOCA data.

PG&E Appeal

- Category A – Use of averaged 25-year and 40-year LOCA frequency data from NUREG-1829 is not supported by applicable guidance.

The NRC uses 25-year LOCA frequency data in the calculation of baseline SPAR model LOCA frequencies. The NRC did not consider 40-year LOCA frequency estimates in developing the baseline SPAR models (Reference 9). The SPAR model LOCA

frequencies for the baseline model are described in Table 1-4 of the SPAR model documentation (*see* Standardized Plant Analysis Risk Model for Diablo Canyon 1 & 2, May 2014). The SPAR model LOCA frequencies are taken directly from NUREG-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." In turn, the LOCA frequencies in NUREG-6928 are taken directly from the 25-year estimates in NUREG-1829 (Reference 8). All of these; the NRC's SPAR model; the NRC's site-specific SPAR model for Diablo Canyon; NUREG-6928, and NUREG-1829; therefore rely on 25-year LOCA frequency data.

Application of 25-year LOCA frequency data to the current circumstances is fully supported by the discussion in NUREG-1829:

> [W]hile aging will continue, the panelists' consensus is that mitigation procedures are in place, or will be implemented in a timely manner, to alleviate significant increases in future LOCA frequencies for existing degradation mechanisms. Because of the predicted stability in these estimates over the near-term, the current-day (25-year) results can be used to represent the LOCA frequencies over the next 15 years of fleet operation.

Unlike the NRC's baseline SPAR model, NUREG-6928, NUREG-1829, and the PSD, the FSD does not use the 25-year LOCA frequency data in NUREG-1829. The FSD therefore is inconsistent with guidance. Use of 25-year data, rather than averaged 25- and 40-year data, results in a reduction in ΔCDF of more than 1.5E-07 per year (*see* Table 3).

<u>Basis No. 2</u>: Proceduralized Actions to Assess Time to Core Damage

> *<u>Summary</u>: The FSD does not accurately credit the procedural requirements of EOP ECA-1.1, Revision 22, when evaluating the time between cessation of ECCS injection flow and the time peak core temperature exceeds 1800°F. PG&E provided a detailed timeline for implementing EOP ECA-1.1, Appendix W, that shows 7.76 hours from cessation of ECCS injection until exceeding 1800°F. This is a significantly longer period of time than was credited in the FSD and extends the time available for implementing electrical and mechanical recovery actions by approximately 5 hours.*

Background

The PSD did not credit EOP-directed actions performed by operators after reaching 4 percent RWST level using Unit 2 EOP ECA-1.1, Revision 22. Specifically, it did not credit alignment of normal charging with suction from the VCT after the RWST level reaches 4 percent in accordance with ECA 1.1, Appendix W.

PG&E presented information at the Regulatory Conference describing the actions taken after reaching 4 percent RWST level using EOP ECA-1.1, Revision 22, including a timeline that depicts RWST inventory and water flow to the RCS through the predicted

time of core damage. The analysis indicates that the time following cessation of ECCS injection flow until peak core temperature reached 1800°F was 2.8 hours. The analysis did not include the actions required by EOP ECA-1.1, Appendix W. PG&E notified NRC that analysis of the effects of restoring normal charging from the VCT after RWST reaches 4 percent level was underway, and the NRC agreed that PG&E could provide that information subsequent to the Regulatory Conference.

On December 6, 2016, PG&E provided an analysis (Reference 5) that credited actions directed by Appendix W. The analysis demonstrates that the time following cessation of ECCS injection flow until a peak core temperature of 1800°F is 7.76 hours. The analysis extends by approximately 5 hours the time available to implement electrical and mechanical recovery actions and to establish recirculation and decay heat removal.

PG&E Appeal

- Category B – The FSD uses 2.8 hours for the time between 4 percent RWST level and core damage. This timeline does not reflect implementation of actual plant procedures to makeup from the VCT to the RCS.

The FSD (at page A-3) assessed 2.8 hours for the time between 4 percent RWST and core damage. The FSD did not accurately credit the action to establish normal charging using Appendix W presented in Reference 5. Reference 5 describes actions directed by EOP ECA-1.1, Revision 22, following RWST reaching 4 percent level.

The procedurally-required action to implement EOP ECA-1.1, Appendix W, following RWST level reaching 4 percent significantly extends the time available for recovery actions. Control Room operators direct and implement these actions. The TSC does not direct this activity. Operation of plant systems in accordance with EOP ECA-1.1, Revision 22, directs:

EOP ECA-1.1, step 5, Check RWST Level – Greater than 4 percent

This is a continuous action step. The Response Not Obtained (RNO) step is to go to step 30. Once the RWST is depleted (less than 4 percent level), as annunciated by a Control Room alarm, operators will transition to step 30 and implement actions as directed.

Reference 5 demonstrates that, at 6.51 hours after RWST reaches the 33 percent level, the RWST would be at the 4 percent level (Table 1). At 6.51 hours after RWST reaches 33 percent, operators start step 30 of EOP ECA-1.1.

EOP ECA-1.1, step 30, STOP all pumps taking suction from the RWST.

EOP ECA-1.1, step 31, TRY To Add Makeup To RCS From Alternate Source:

Makeup to RCS from VCT through Normal Charging Line, IMPLEMENT Appendix W

PG&E modeled 30 minutes of no makeup to the RCS while operators perform the alignments directed by EOP ECA-1.1, Appendix W. At 7.01 hours after reaching 33 percent level, makeup to the RCS from the VCT, as supplied by the blender, is initiated at the maximum makeup flow of 130 gallons per minute (gpm). This makeup rate is not sufficient to match the decay heat load required flow for continued cooling, but does significantly extend the time until core damage. The procedurally required action to implement EOP ECA-1.1, Appendix W, following RWST level reaching 4 percent significantly extends the time available for recovery actions.

The FSD states that the time available for recovery actions was less than five times that required for recovery actions. This indicates that the FSD did not credit the actions directed by EOP ECA-1.1, Appendix W, to place normal charging in service for the time between cessation of ECCS injection and peak core temperature exceeding 1800°F. As clarified by Reference 7, the FSD considered normal makeup to the RCS from normal charging when evaluating additional TSC/ERO-directed recoveries. As discussed above, this recovery action should be considered when evaluating Control Room-directed recoveries, not TSC/ERO-directed recoveries. Successful completion of these actions adds approximately 5 hours to the available recovery time as demonstrated by MAAP analysis. If this added time had been credited, the available time for recovery (approximately 14 hours) would be greater than five (5) times that required for recovery actions.

<u>Basis No. 3</u>: Reference to Superseded Procedure When Assessing Operator Actions, Performance Shaping Factors, Timing of Recovery Actions, Sequence of Recovery Actions, and Dependency

> *<u>Summary</u>: The FSD references a superseded version of EOP E-1.3 when assessing operator actions, evaluating performance shaping factors, and developing a timeline and sequence for recovery actions. Using current procedures, Control Room-directed EOPs and TSC-directed local recovery actions proceed in parallel, rather than sequentially as assessed in the FSD. Two TSC-directed local recovery actions (electrical and mechanical recovery) also proceed in parallel using separate response teams, rather than sequentially as assessed in the FSD. Based on plant staff roles and responsibilities, NRC's use of high dependency among recovery actions is inconsistent with the SPAR-H method. Use of current procedural information to assess strategies to increase the time available for recovery methods and evaluate the timing and sequence of recovery actions results in a risk reduction greater than 5.5E-07 per year.*

Background

In the PSD, the NRC did not consider operator actions performed as directed by EOPs. EOPs call for operators to initiate reactor system cooldown, throttle ECCS flow to the core, refill the RWST after reaching the 33 percent level, and establish normal charging after the RWST reaches 4 percent level. Consistent with the analysis presented by PG&E following identification of the performance deficiency, the PSD identified step 2.d

in EOP ECA-1.1, Revision 21, as the step that would lead operators to locally operate the valve as required. The NRC did not identify EOP E-1.3 as the procedure that would lead operators to local operation of Valve SI-2-8982B. The PSD therefore modeled two recovery methods (local electrical and mechanical) as being pursued in parallel, with the electrical recovery method ready for attempted use first. The PSD found that the total time to success for the electrical recovery would be approximately 1 hour and 40 minutes after reaching 33 percent RWST level. The PSD found that the total time to success for the manual recovery methods was approximately 2 hours and 35 minutes after reaching 33 percent RWST level.

On August 17, 2016, PG&E provided NRC the procedures used in response to an accident with failure of Valve SI-2-8982B to open: EOP E-1.3, Revision 22, and EOP ECA-1.1, Revision 22. At the Regulatory Conference, PG&E presented a timeline for the RWST inventory that credits operator actions performed in accordance with these EOPs. *See* Table 1 (Attachment 1). PG&E described these operator-implemented Control Room-directed actions at the Regulatory Conference. PG&E did not discuss TSC assistance for these actions because they are independent of any interaction with, or support from, the TSC. PG&E also described the manner in which the Control Room would contact the TSC to identify and implement actions to open Valve SI-2-8982B following entry into ECA-1.1. While these Control Room-directed operator actions performed in accordance with the EOPs affect the RWST inventory timeline, they do not directly provide for successful recovery of Valve SI-2-8982B. The actions do, however, increase the time available for TSC-directed actions to recover Valve SI-2-8982B through electrical and mechanical recovery methods.

At the Regulatory Conference, PG&E reiterated that two TSC-directed recovery methods (local electrical and mechanical) would be pursued in parallel by separate response teams, consistent with NRC's analysis in the PSD. PG&E explained that the TSC would coordinate recovery efforts with the OSC without burdening the Control Room. PG&E also discussed parallel coordination of the two TSC-directed activities and noted that the TSC would direct the first method ready in the field to proceed first. The timing for parallel local electrical and mechanical recoveries is presented in Table 2 (Attachment 2).

Subsequent to the Regulatory Conference, PG&E performed additional analyses of procedurally-directed actions that extend the time available to perform Valve SI-2-8982B recovery actions and provided these to the NRC.

PG&E Appeal

As discussed below, this appeal basis relates to the timeline and sequence of events associated with Control Room-directed EOPs and TSC-directed local recovery actions, as well as the dependency among these actions.

Control Room-Directed EOP Actions That Extend the Time to Core Damage

- Category B – The FSD references a superseded procedure and does not reflect actual plant procedures in effect during the period of interest.

The FSD statement (at page A-7) that there is "uncertainty associated with likelihood of these recoveries because they involve diagnostic troubleshooting and assessment by the TSC staff," is not supported by current EOPs, as discussed above and as shown in Table 1. EOP ECA-1.1 would require Control Room operators to initiate action to refill the RWST and secure ECCS flow at approximately 9 and 12 minutes, respectively, after 33 percent RWST level, while the TSC would be developing the recovery actions. These Control Room-directed activities, which extend the time to core damage after 33 percent but before 4 percent RWST level, involve no diagnosis and do not require TSC support or action.

In Section 4 of the FSD, the NRC states:

> Throttling of ECCS flow is directed by [EOP ECA] 1.1, "Loss of Emergency Coolant Recirculation," Revision 21, Step 18. This procedure directs operators to stop all but one ECCS centrifugal charging pump, provided the reactor coolant system is at least 70°F subcooled. This action could occur at various times during the reactor coolant system cooldown and results in a reduction in ECCS flow to approximately 400-500 gpm.

As shown in Table 1, all but one ECCS CCP would be secured at approximately 21 minutes after reaching 33 percent RWST level in accordance with EOP ECA-1.1, step 13. Further, stopping all but one ECCS CCP is not dependent upon achieving at least 70°F subcooling.

The RNO step (step 16.b) results in an operator determination that only one CCP is required for decay heat load. Based on EOP instructions, the actions would occur at the times presented in Table 2, rather than, as the FSD concludes (at A-2), "at various times during the reactor coolant system cooldown."

The directions and actions in the applicable procedure revisions also do not support the FSD conclusion (at pages A-3 to A-4) that "the initial attempt to mechanically open Valve SI-2-8982B would occur prior to any TSC action to refill the RWST or throttle ECCS flow … because these actions are directed by EOP emergency contingency action procedures, which are implemented after the failure to open Valve SI-2-8982B and Valve SI-2-8982A during implementation of Procedure EOP E-1.3." The only actions pursued by the TSC are the actions to locally open Valve SI-2-8982B using electrical and mechanical methods. The TSC-directed actions to locally open Valve SI-2-8982B will still be in the diagnosis phase at this time. There are no constraints preventing operators from securing ECCS flow prior to initial TSC-directed attempts to recover Valve SI-2-8982B.

This timing and sequence of operator actions increases the time available to recover the SI-2-8982B Valve relative to the FSD timeline, as discussed below.

TSC-Directed Electrical and Mechanical Recovery Actions

- Category B – The FSD references a superseded procedure and does not reflect actual plant procedures in effect during the period of interest.

In Section 9, the FSD (at A-7) states:

> Based on the above, the NRC found that the proposed recovery actions are more reflective of sequentially directed actions rather than parallel actions. The NRC considered the continuous action nature of ECA-1.1, step 2, which allows the TSC to pursue multiple methods to recover ECCS recirculation following the initial failure of Valve SI-2-8982B and the inability to recover the valve by local manual operation.

The FSD's description of EOP ECA-1.1, step 2, is not supported by procedures, in that step 2 allows the TSC to pursue multiple methods to recover ECCS recirculation, including both local electrical and mechanical operation. The FSD statement that step 2 allows pursuit of multiple methods "to recover ECCS recirculation following the initial failure of Valve SI-2-8982B and the inability to recover the valve by local manual operation" reflects guidance in superseded EOP E-1.3, Revision 15.

As discussed previously, use of applicable revisions of EOP E-1.3 and EOP ECA-1.1 results in no actions for local recovery of Valve SI-2-8982B until EOP ECA-1.1 step 2.d is reached. At that point, the Control Room would contact the TSC and turn over responsibility for developing and implementing actions to recover and open the SI-8982A and B Valves by both local electrical and mechanical means. The TSC would then pursue the electrical and mechanical recovery methods (*see* Table 2).[4]

a. Electrical Recovery

Section 8 of the FSD references a superseded procedure when describing the timeline for electrical recovery of Valve SI-2-8982B. The FSD concludes that the local electrical recovery method would be completed approximately 209 minutes after RWST level reached 33 percent (Reference 7). PG&E determined, based on application of current procedures, that the electrical recovery option would be completed approximately 100 minutes after RWST level reached 33 percent. (Like PG&E, the PSD found that the total time to success for the electrical recovery would be approximately 100 minutes after reaching 33 percent RWST level, less than half the time assumed in the FSD.)

The FSD references Unit 2 EOP E-1.3, Revision 15, step 6.b.2 RNO, as the step that would lead operators to local recovery attempts. The FSD does not assume that

[4] Only the electrical and jumper recovery methods would credibly be pursued in sequential manner.

EOP ECA-1.1 actions would lead to parallel operator recoveries.[5] Instead, the FSD states that electrical recovery is delayed due to EOP E-1.3, which "first directs operators to manually or locally open Valve SI-2-8982B with assistance from mechanical maintenance at the 64-foot residual heat removal penetration." EOP E-1.3, Revision 15, was issued for use on May 17, 2006, and the RNO for step 6.b.2 was removed in Revision 18, dated September 30, 2010. EOP E-1.3, Revision 22, directs transition to EOP ECA-1.1 if Valves SI-2-8982A and SI-2-8982B both fail to open. EOP E-1.3, Revision 22, does not direct operators to manually or locally open Valve SI-2-8982B.

In concluding that the local electrical recovery option would be completed approximately 209 minutes after RWST level reached 33 percent, the FSD referenced and apparently relied on superseded procedural guidance (or else interpreted the actions required by applicable EOPs in manner inconsistent with rules of usage). The FSD's timing indicates that the electrical and manual recoveries were sequential (a 46-minute delay for indication and diagnosis (*see* Reference 7), 103 minutes for the manual recovery attempt, and then 60 minutes for the electrical recovery). Use of Revision 22 eliminates a potential delay associated with the Control Room directing local recovery and leads to completion of electrical recovery approximately 100 minutes after RWST level reached 33 percent. Using the Revision 22 timelines, the time available for electrical recovery of Valve SI-2-8982B would be greater than two times the time required for Diagnosis and greater than five times the time required to perform the Recovery Action.

The SPAR-H method as described in NUREG/CR-6883 discusses use of a Time Available PSF of "extra" for human factors engineering (HFEs) that have very long time windows. Section 2.4.4.1 of NUREG/CR-6883 specifically states that the "extra" Time Available PSF for Action should be used whenever the time available is greater than 5 times the time required for action. This guidance therefore supports assessing the Time Available PSF as "extra" for the electrical recovery action.

The FSD references guidance from INL/EXT-10-18533, "SPAR-H Step-by-Step Guidance," Revision 2, Section 3.1, "Time Available," in assigning the Time Available PSF for Action as "nominal." This guidance indicates that the Time Available PSF for Action typically should be assessed as "nominal" and the remainder of the time applied to the Diagnosis assessment. However, the current Risk Assessment Standardization Project (RASP) Handbook Section 9.3 (at note 42) acknowledges that "[w]hile this may be appropriate for most at-power situations, lower HEPs are possible for HFEs for which very long time periods are available (e.g., shutdown HFEs, containment venting, refilling reactor water storage tank, etc.)."[6] Here, and in accord with Section 2.4.4.1 of NUREG/CR-6883, there is a very long time period available for the electrical recovery action. Approximately 8 hours are available prior to reaching peak core temperature

[5] In Reference 7, the NRC noted that, while the TSC *could* pursue electrical and mechanical recovery methods in parallel, application of station procedures would lead to certain portions of the recovery actions being sequential. As discussed in this appeal basis, application of applicable station procedures in fact leads to the electrical and mechanical recovery methods being pursued in parallel, with a potential delay in one action of approximately 5 minutes to account for possible overlap. *See also* Table 2.
[6] The RASP Handbook references NUREG/CR-6883 as the basis for the SPAR-H methodology.

without crediting normal charging to the RCS. (Approximately 14 hours are available prior to reaching peak core temperature with crediting normal charging to the RCS.) This supports use of a Time Available PSF for the electrical recovery Action that is better than "nominal." As a result, both NUREG/CR-6883 and the RASP Handbook support use of the "extra" Time Available PSF for the electrical recovery action.

The overall timeline also supports use of the "extra" Time Available PSF for Action and "expansive" time for Diagnosis. Specifically, two times the longest diagnosis time of 1 hour (conservatively rounded up from the FSD 46 minutes) for the electrical recovery Diagnosis (the criteria for use of the "expansive" Time Available PSF for Diagnosis) added to five times the recovery Action time of 1 hour for electrical recovery (the criteria for use of "extra" Time Available PSF for Action), yields a total time of 7 hours. This is still well within the total time available of 14 hours.

b. <u>Mechanical Recovery</u>

Section 7 of the FSD (at pages A-3 to A-5) includes an updated assessment of the likelihood of success of local mechanical recovery of Valve SI-2-8982B that does not reflect the timeline and sequence of events using current EOPs. The FSD concludes that local manual recovery would be completed approximately 133 minutes after RWST level reached 33 percent (including 30 minutes diagnosis time) (Reference 7). In contrast, PG&E concludes that the mechanical recovery method would be completed approximately 100 minutes after RWST level reached 33 percent. *See* Table 2 (note a).

Time to Complete Recovery Actions (after 33% RWST Level)			
	PSD	**PG&E**	**FSD**
Electrical Recovery Method	100 minutes	100 minutes	209 minutes
Manual Recovery Method	155 minutes	115 minutes	≥133 minutes[a]
Sequence of Recoveries	Parallel	Parallel	Sequential[b]

[a] In Reference 7, the NRC assumed 30 minutes for diagnosis, followed by approximately 103 minutes of manual action to access and open Valve SI-2-8982B. In the PSD, the NRC assumed an additional 10 minutes "to attempt swap over to recirculation," which would bring the total to 143 minutes after 33 percent RWST level.

[b] NRC found that recovery actions are "more reflective" of sequential actions (Reference 2) and that "certain portions of the recovery actions were sequential" (Reference 7).

As shown in Table 1, the ECCS would be reduced to a single train at 12 minutes, and the remaining SIP would be secured at 21 minutes. Although several steps would be completed by operators after reaching 33 percent RWST level, demonstrated performance from simulator observation, along with parallel TSC pursuit of local electrical and mechanical recovery, conflicts with NRC's conclusion that EOPs would

not call for reduction of ECCS injection to only one train of charging injection "until numerous steps had been completed after reaching the 33 percent level in the RWST." The most probable way to reach the FSD conclusion is by assuming that operators would remain in EOP ECA-1.1 step 2.d until after the initial attempts to locally open Valve SI-2-8982B through electrical or mechanical methods. Such a Control Room delay is plausible only by applying the superseded EOP E-1.3, Revision 15.

The FSD characterized the Time Available PSF for the manual recovery as "nominal," citing both its assessment of the time available (less than five times the action time for manual recovery) and the discussion in "SPAR-H Step-by-Step Guidance," Revision 2. However, credit for Control Room-directed actions in parallel with TSC-directed electrical and mechanical recovery actions (also pursued in parallel) results in more than 14 hours available for recovery. As noted above, the SPAR-H method as described in NUREG/CR-6883 supports use of the "extra" Time Available PSF for very long time windows (*i.e.*, where the time available is greater than 5 times the time required for action). Use of "extra" Time Available PSF for the mechanical recovery action is appropriate because the time available is more than five times the time required for the manual recovery action. This conclusion is consistent with the RASP Handbook, which allows for use of a Time Available PSF better than "nominal" when "very long time periods are available." Both NUREG/CR-6883 and the RASP Handbook therefore support use of the "extra" Time Available PSF for the mechanical recovery. The timeline associated with manual recovery Diagnosis also supports use of the "expansive" Time Available PSF. PG&E conservatively did not change the time available PSF for mechanical recovery even though a change was justified. Only the electrical recovery time available PSF was adjusted when calculating the updated ΔCDF for this appeal basis.

Time Available PSF			
	PSD	**PG&E**	**FSD**
Electrical Recovery Action	Extra	Extra	Nominal
Manual Recovery Action	Nominal	Nominal[7]	Nominal

[7] Although Extra time is justified (Time available is greater than 5 times the time required), Nominal is conservatively used.

Dependency

PG&E Appeal

- Category A – The dependency analysis used in the FSD was not performed in accordance with SPAR-H guidance.

As discussed below, the NRC's application of high dependency to the electrical and mechanical recovery actions and to Control Room-directed EOP actions is not in accordance with the SPAR-H method (NUREG/CR-6883).

a. Dependency Among TSC Recovery Actions

In FSD Section 9, the NRC states that the same crew would be used for the TSC-directed recoveries. In fact, different crews would be used. Electrical recovery would require trained operators to perform the actions, with possible assistance of electricians for print reading. (Operators specifically receive training on electrical print reading, so electrician involvement may not be necessary.) Mechanical recovery would involve one operator, a chemistry/radiation protection technician for confined space sampling, and mechanics.[8] Electrical and mechanical recoveries also occur in different locations. The only common element among these recovery methods is the TSC, which diagnoses the need for and coordinates the parallel activities. Table 2 shows the coordinated timeline for these parallel activities. Moreover, there are strong visual and audible cues of success or failure for each recovery strategy, including local Valve position indication, overcurrent trip indication at the motor control center (MCC), and Control Room position indications and alarms.[9] Application of high dependency to the electrical and mechanical recovery actions in the FSD is not in accordance with the SPAR-H method (NUREG/CR-6883).

b. Dependency Among Control Room-Directed EOP Actions

The actions taken by Control Room operators to extend the time to core damage following RWST level reaching 33 percent with the inability to enter containment sump recirculation are independent of TSC-directed actions to perform electrical and mechanical recovery actions. The EOP-directed time-extending actions performed by Control Room operators to reduce ECCS flow, makeup the RWST, and provide makeup to the RCS using the normal charging path are dependent on the same operator crew and occur close in time. However, the TSC, as part of its monitoring function, would independently follow along with the EOPs and would provide cues to the Control Room if expected plant responses consistent with the EOPs were not observed. The TSC's monitoring function and its ability to identify issues with operator performance therefore act to limit the dependency of time extending actions. Control Room actions to extend

[8] The jumper recovery would only involve electricians. The jumper method would not be pursued until after local electrical recovery had been attempted.
[9] These alarms are communicated to operators at the MCC through the continuous communication required by Procedure OP O-22.

the time to core damage should therefore be assessed as having moderate dependency in accordance with the NRC's SPAR-H method.

c. Implications for Significance Determination

The NRC's application of a 50 percent effective failure probability for the recoveries listed in the FSD due to high dependency for all TSC-directed activities is not supported by actual plant staff roles and responsibilities for the recoveries or the makeup of the crews for each recovery method. Plant staff roles and responsibilities are reflected in procedures (EP EF-1, EP EF-2, and EOPs). Recovery actions should be assessed as having complete diagnosis dependency and zero dependency between actions.

<table>
<tr><th colspan="5">Dependency Among Operator Actions</th></tr>
<tr><th colspan="3">Actions</th><th>PG&E</th><th>FSD</th></tr>
<tr><td rowspan="4">TSC-Directed Recovery Actions</td><td rowspan="4">Valve SI-2-8982B Local Mechanical, Electrical and Jumper</td><td>Diagnosis Dependency</td><td>Complete</td><td rowspan="2">High</td></tr>
<tr><td>Action Dependency</td><td>Zero</td></tr>
<tr><td>Basis for Diagnosis</td><td>Same Crews (TSC), Same Location</td><td rowspan="2">Same Crews, Close In Time, No Cues</td></tr>
<tr><td>Basis for Action</td><td>Actions proceed independently once diagnosis is made</td></tr>
<tr><td rowspan="2">Control Room-Directed EOP Actions</td><td rowspan="2">Refill RWST, Reduce ECCS flow, Depressurize RCS, RCS makeup from VCT</td><td>Dependency</td><td>Moderate</td><td>High</td></tr>
<tr><td>Basis</td><td>Same Crews, Close in Time, Cues from TSC</td><td>Same Crews, Close in Time, No Cues</td></tr>
</table>

<u>Summary of Appeal Basis No. 3</u>

Table 3 (Attachment 3) summarizes the reduction in ΔCDF from the FSD, as well as the updated total ΔCDF, taking into account the Table 1 timeline, the resultant changes in PSFs, characterization and assessment of dependencies for TSC-directed and Control-Room directed recoveries based on procedurally-directed roles, and credit for parallel activities. This results in a reduction in ΔCDF from the FSD greater than 5.5E-07 per year.

<u>Basis No. 4</u>: Application of SPAR-H Guidance for the Mechanical Recovery Procedure PSF

> *<u>Summary</u>: The FSD used the Procedure PSF for opening the recirculation valve chamber guard without first assessing whether Procedures are in fact a performance driver for the subject HFE as directed by SPAR-H Step-by-Step Guidance. The simplicity and ease of the action to remove chamber closure bolting supports PG&E's conservative selection of an "available but poor" Procedure PSF. Use of the "available but poor" Procedure PSF results in a risk reduction greater than 5E-07 per year.*

Background

The PSD assessed the likelihood of success of local recovery of Valve SI-2-8982B in a manner generally consistent with the original analysis of time required and time available to perform recovery actions presented by PG&E following identification of the performance deficiency. Subsequent to the PSD, PG&E performed additional analyses of procedurally-directed actions that extend the time available to perform recovery actions. PG&E also prepared a real-time video showing the start-to-finish evolution of local mechanical recovery as it would be performed following an accident to illustrate its ease and simplicity.

Section 7 of the FSD (at pages A-3 to A-5) includes an updated assessment of the likelihood of success of local mechanical recovery of Valve SI-2-8982B. The FSD notes that there is not an existing emergency procedure to open the SI-2-8982B Valve chamber guard and that, during the postulated event, existing outage-related work instructions would be used to develop the emergency instructions to open the chamber guard to allow for the mechanical recovery method. The NRC concluded that this lack of guidance supports use of an "incomplete" Procedure PSF, rather than "available but poor."

PG&E Appeal

- Category A – SPAR-H Step-by-Step guidance, Section 3.5, Procedures, directs the NRC to demonstrate that the procedure is a performance driver for opening the chamber guard cover as a prerequisite to evaluating the Procedure PSF quantitatively.

The SPAR-H Step-by-Step guidance Section 3.5, Procedures, states:

> [A]s with all PSFs, in SPAR-H, a prerequisite to evaluating this PSF quantitatively is the qualitative determination of whether or not Procedures are in fact a performance driver for the subject HFE.

At the Regulatory Conference, PG&E presented a real-time video showing the local mechanical recovery evolution as it would be performed following an accident, including opening the hinged valve chamber guard cover. The video illustrates the ease and

simplicity of the actions required to open the hinged valve chamber guard cover by removing the lug nuts on the chamber door (*i.e.*, on par with removing the lug nuts to change a car's tire). The simplicity of these actions substantiates that procedures would be of minimal significance to successful performance. PG&E conservatively modeled the Procedure PSF as "available but poor."

The FSD concludes (at page A-4) that the Procedure PSF should be classified as "incomplete," but does not provide a basis to demonstrate that the Procedure is a performance driver for the HFE of opening the chamber guard cover. Because the FSD does not provide such a justification, the FSD is inconsistent with applicable SPAR-H, Revision 2, guidance and lacks justification. The FSD should be reassessed in accordance with applicable guidance. Use of the "available but poor" Procedure PSF results in a reduction in ΔCDF from the FSD greater than 5E-07 per year.

Procedure PSF			
	PSD	**PG&E**	**FSD**
Electrical Recovery Action	Incomplete	Available But Poor	Available But Poor
Manual Recovery Action	Incomplete	Available But Poor	Incomplete

<u>Basis No. 5</u>: Recovery Time Available for SLOCAs

> *<u>Summary</u>: At the Regulatory Conference, PG&E discussed the impact that an evaluation of the SLOCA recovery timeline could have on the overall risk significance. There was no need, however, to prepare a separate analysis for SLOCAs because the NRC had used the "extra" Time Available PSF in the PSD (consistent with PG&E's initial assessment). The NRC changed this PSF to "nominal" in the FSD without providing PG&E an opportunity to respond. Had PG&E been given the opportunity to address the characterization of the electrical recovery Time Available PSF as "nominal," or had NRC considered SLOCA recovery timelines as noted by PG&E at the Regulatory Conference, the analysis would demonstrate that the "extra" Time Available PSF is appropriate for SLOCA recovery actions. Use of this PSF results in a risk reduction greater than 3.5E-07 per year.*

Background

The PSD used a timeline to RWST depletion and core damage that did not credit operator actions to reduce ECCS flowrate or provide makeup to the RWST. The timeline was based on a 3.5 inch diameter LOCA and resulted in use of a "nominal" Time Available PSF for mechanical recovery actions and "extra" Time Available PSF for electrical recovery actions.

At the Regulatory Conference, PG&E provided information on operator actions that extend the timeline to core damage for LOCAs, including reducing ECCS flow and makeup of spent fuel pool inventory to the RWST. PG&E provided a timeline based on best estimate operator response times and assessed a sensitivity case that evaluated the impact of delayed operator action. PG&E also explained that smaller LOCAs (less than 2 inches) would have longer timelines due to the reduced rate of inventory loss.

The FSD credits EOP actions to reduce ECCS flowrate and makeup to the RWST, but applies the same 3.5-inch LOCA timeline to all small and medium break sizes. The FSD therefore considers a shorter timeline than would be expected for smaller LOCAs. Because the NRC did not credit the longer available timelines associated with smaller LOCAs, noted by PG&E at the Regulatory Conference, the NRC selected the "nominal" Time Available PSF for local electrical and mechanical recovery actions associated with SLOCAs.

PG&E Appeal

- Category A – The NRC changed the Time Available PSF from "extra" in the PSD to "nominal" in the FSD without separately accounting for SLOCA recovery timelines, as discussed at the Regulatory Conference.

The FSD presents a different characterization of the Time Available PSF for the electrical recovery of Valve SI-2-8982B than that in the PSD. Specifically, the NRC characterized the Time Available PSF as "extra" in the PSD (consistent with PG&E's initial assessment and the information presented by PG&E at the Regulatory Conference), but then changed the PSF to "nominal" in the FSD. PG&E was not given the opportunity to respond to this change in characterization as indicated by Inspection Manual Chapter (IMC) 0609, Attachment 1, page 7, which states that the NRC must provide the licensee with sufficient information and detail to enable the licensee to determine what additional information is needed to inform the FSD. This change was not based on information presented at the Regulatory Conference. Had PG&E been given the opportunity to respond to the NRC's change from the "extra" to "nominal" Time Available PSF as directed by IMC 0609, PG&E would have provided a timeline analysis for SLOCAs, consistent with information noted by PG&E at the Regulatory Conference. This analysis shows that sufficient time is available to appropriately characterize the SLOCA recovery action Time Available PSF as "extra" for both electrical and mechanical recovery actions in accordance with both NUREG/CR-6883 and the RASP Handbook (see above discussion of the Time Available PSF and NUREG 6883 under Basis No. 3).

Because the NRC did not provide PG&E with an opportunity to respond to the change in the characterization of a critical recovery action as required by IMC 0609, Attachment 1, the FSD results do not reflect the risk significance of the violation. The NRC's choice of "nominal" Time Available PSF for SLOCAs is not justified in light of information presented at the Regulatory Conference regarding the longer timelines for SLOCAs due

to the reduced rate of inventory loss. Proper evaluation of the recovery Action PSFs for SLOCAs results in reduction in ΔCDF greater than 3.5E-07 per year (*see* Table 3).[10]

<u>Basis No. 6</u>: Use of a Range To Assess Overall Risk Significance

> *<u>Summary</u>: Quantitative evaluations in the FSD should be based on a single value (i.e., point estimate) that reflects the "best available information," supplemented, as necessary, by sensitivity evaluations Use of a range, rather than a sensitivity evaluation as discussed in Manual Chapter 0609, Attachment 1, also is not supported by SDP guidance. And, the "upper range" value in the FSD, which is simply the same value used in the PSD, does not reflect any changes associated with information that PG&E provided at the Regulatory Conference.*

Background

The PSD estimated that the ΔCDF from the performance deficiency was 7.6E-06 per year. PG&E provided additional information at the Regulatory Conference to ensure that the final result credited actual (verifiable) plant hardware, procedures, and equipment configurations and that it reflected revised assumptions for various risk-related parameters.

Unlike the PSD, the FSD does not identify a single value for the ΔCDF based on the "best available information." Instead, the FSD reports a <u>range</u> of values for the ΔCDF associated with the performance deficiency. The NRC concludes that, using revised assumptions based on information provided by PG&E, "the lower range of increase in [CDF]" is 1.3E-06 and that its PSD ΔCDF result of 7.6E-06 continues to "represent the upper range of the increase in [CDF] associated with the performance deficiency." The NRC therefore did not alter its assessment of the upper end of the ΔCDF based on information provided by PG&E. Further, the cover letter indicates that "[b]ecause the NRC's calculated lower and upper estimations of the increase in [CDF] of the performance deficiency were both greater than 1.0E-06 per year but less than 1.0E-05 per year," the finding is White. The NRC therefore used the range, the upper value of which was not based on best available information, as an input to conclude that the final significance of the finding is White.

PG&E Appeal

- Category A – Use of a range of values is inconsistent with applicable SDP guidance, including IMC 0308, Attachment 3, and IMC 0609, Attachment 1. The

[10] The ΔCDF from separate consideration of SLOCAs is enveloped by consideration of the timeline for all recoverable LOCAs as presented by PG&E. Accordingly, consideration of this appeal basis is unnecessary when the appropriate timelines and sequences are properly accounted for in the risk evaluation. If, however, the NRC does not use the timeline and sequences presented by PG&E, then separate consideration of SLOCAs results in a substantial risk benefit as a stand-alone appeal.

FSD does not specify the result as a single mean value, or point estimate, based on the "best available information."

- Category B – The NRC's "upper range" of the ΔCDF in the FSD, which is the same as the ΔCDF in the PSD, does not account for actual plant hardware, procedures, and equipment configurations. The upper end of the range should be reassessed based on the new information presented at the Regulatory Conference.

There is no basis under IMC 0609 for the NRC to apply a PSD that has been substantially revised based on new and revised information as the "upper range" that is then used as a basis for the FSD and overall finding. Doing so is inconsistent with the process defined in IMC 0609, Attachment 1, Section 02.04.b, Item 4, for obtaining information in the Regulatory Conference and conducting a post-conference review and final Significance and Enforcement Review Panel (SERP) in order to reach the FSD. Any assessment of a "range" in CDF increase should be based upon appropriate and documented sensitivity evaluations. *See* Exhibit 2, at E2-1, SERP Worksheet, *General Guidance*, point 2; E2-3, *For Quantitative Appendices*; and E2-5, *Significance Determination (Quantitative)*.[11] The PSD should not be a basis for the White finding.

In addition, PG&E provided information at the Regulatory Conference regarding the inputs and assumptions used in the PSD. The NRC agreed with this information, at least in part. However, the NRC did not re-establish the upper limit of the range used in the FSD based on any of this new information. Accordingly, the upper bound for risk used in the FSD does not reflect actual plant hardware, procedures, or equipment configurations.

PG&E is appealing this aspect of the FSD to ensure that the FSD specifies the result as a single mean value, or point estimate, based on the "best available information" in accordance with established SDP requirements. Any use of a range of values also should be defined as the calculated point estimate adjusted by sensitivity analyses.

<u>Overall Conclusion</u>

Based on the information provided to the NRC before, at, and immediately following the Regulatory Conference, PG&E concludes that the finding is most appropriately classified as having very low safety significance (Green). Table 3 summarizes the

[11] *See also* Regulatory Guide 1.174, Revision 2 (May 2011), at 21 ("Because of the way the acceptance guidelines (Section 2.4) were developed, the appropriate numerical measures to use in the initial comparison of the PRA results to the acceptance guidelines are mean values."); NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Volume 1 (March 2009), at 52 ("In summary, the present recommended practice is to use the mean of the risk metric to compare to the relevant acceptance guidelines …"); NUREG-1855, Revision 1, Draft Report for Comment (March 2013), at 2-8 ("The standard (as endorsed by the NRC) requires the calculation of mean values for the parameters which are used to calculate the either the frequency or probability of the significant contributors."); *id.* at 2-9 ("For CDF and LERF, the standard (with NRC endorsement) requires that a mean value be calculated that is based on the mean values of the significant input parameters …").

reduction in ΔCDF relative to the FSD, as well as the total ΔCDF associated with each of the appeal bases. Consideration of the best available information for this performance deficiency results in an increase in core damage frequency of less than 6E-07 per year.

References

1. NRC Letter, "Diablo Canyon Power Plant – NRC Inspection Report 05000275/2016010 and 05000323/2016010, Preliminary White Finding," dated October 3, 2016 (EA-16-168) (ADAMS Accession No. ML16277A340)

2. NRC Letter, "Diablo Canyon Power Plant – Final Significance Determination of a White Finding, Notice of Violation, and Follow-Up Assessment Letter; NRC Inspection Report 05000275/2016010 and 05000323/2016010," dated December 28, 2016 (EA-16-168) (ADAMS Accession No. ML16363A429)

3. PG&E Regulatory Conference Presentation, "Diablo Canyon Power Plant Preliminary White Finding, Limit Switch Work Instructions," dated November 15, 2016 (ADAMS Accession No. ML16335A439)

4. MAAP Calculation File MAAP 16-03, Revision 0, LOCA Loss of Recirculation Function. November 18, 2016

5. MAAP Calculation File MAAP 16-03, Revision 1, LOCA Loss of Recirculation Function Supplement. December 6, 2016

6. MAAP Calculation File MAAP 16-03, Revision 2, LOCA Loss of Recirculation Function Supplement. January 10, 2017

7. NRC Letter, "NRC Response to Questions Involving Diablo Canyon Power Plant – Final Significance Determination of a White Finding, NRC Inspection Report 05000275/2016010 and 05000323/2016010," (ADAMS Accession No. ML17017A437), dated January 17, 2017

8. R. Tregoning, L. Abramson, and P. Scott, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process*, NUREG-1829, U.S. Nuclear Regulatory Commission, Washington, DC, April 2008

9. S.A. Eide, D.M. Rasmuson, C.L. Atwood, *Estimating Loss-Of-Coolant Accident Frequencies for the Standardized Plant Analysis Risk Models,* 2008 (ADAMS Accession No. ML081710770)

ATTACHMENT 1

The following timeline for the RWST inventory credits operator actions taken in accordance with the Unit 2 EOP E-1.3, Revision 22, and EOP ECA-1.1, Revision 22.

Table 1: Procedure Implementation and Response Timeline

Time after 33% RWST – Control Room-Directed Operator Actions: Procedure and Steps	
T = 0 mins	**33% RWST level and resultant RHR pump trips**
	• EOP E-1.3, step 9.b, Open 8982B, RHR Pp 2-2 Suct from Contmt Recirc Sump • EOP E-1.3, response not obtained for step 9.b, GO TO step 10 (Page 5) • EOP E-1.3, step 10, Crosstie SI Pp Suction to CCP Suction • EOP E-1.3, step 11.b, Open 8982A, RHR Pp 2-1 Suct from Contmt Recirc Sump • EOP E-1.3, response not obtained for step 11.b, GO TO step 12 (Page 6) • EOP E-1.3, step 12, Check at least one Train of Cold Leg Recirc • EOP E-1.3, response not obtained for step 12, GO TO EOP ECA-1.1, LOSS OF EMERGENCY COOLANT RECIRCULATION.

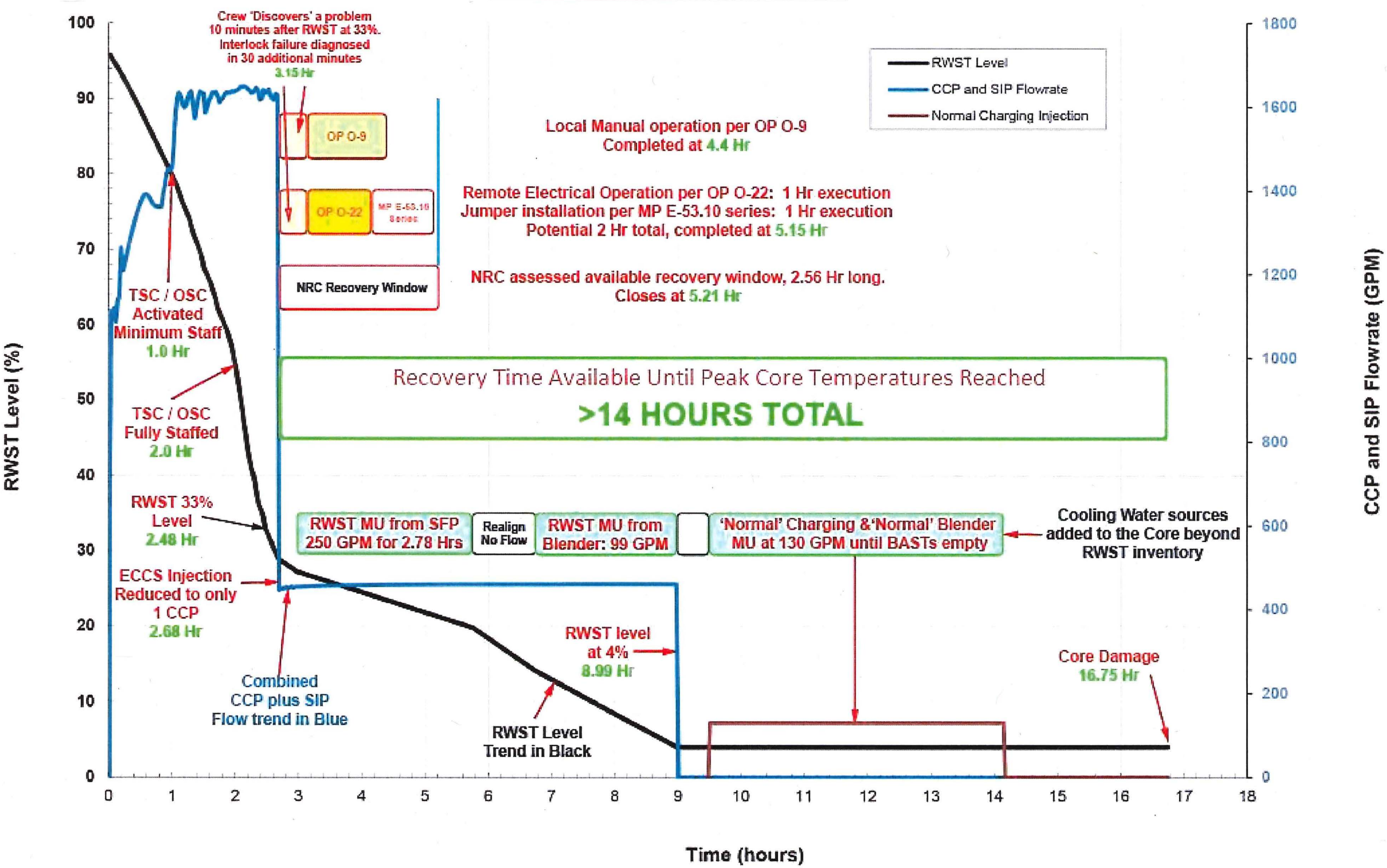
Time after 33% RWST – Control Room-Directed Operator Actions: Procedure and Steps	
T = 3 mins	**Exit EOP E-1.3 (time based on observed simulator performance)**
T = 4 mins	**Enter EOP ECA-1.1 (time based on observed simulator performance)**
	• EOP ECA-1.1, step 2.d, "response not obtained" action, TRY to restore Emergency Coolant Recirculation Equipment by locally operating valves as required. *ECA-1.1 step 2 is a continuous action step. EOP rules of usage require operators to continue on in the procedure while any actions initiated for local operation continue in parallel with the operator actions.* *At this point the Control Room contacts the TSC and turns over responsibility for development and implementation of actions to recover and open Valves 8982A & B, by both local electrical and mechanical means. Refer to Table 2 for a timeline of the electrical and mechanical recoveries. PG&E has conservatively modeled the time of TSC notification as 10 minutes following 33% RWST level.* • EOP ECA-1.1, step 5, Check RWST Level – Greater than 4%. *This is a continuous action step. The response not obtained is to go to step 30. Once the RWST is depleted (<4%) operators will transition to step 30 and implement actions as directed. This occurs later in the timeline.*

<table>
<tr><th colspan="2">Time after 33% RWST – Control Room-Directed Operator Actions: Procedure and Steps</th></tr>
<tr><td>T = 8 mins</td><td>Initiate Appendix M (time based on observed simulator performance)</td></tr>
<tr><td></td><td>EOP ECA-1.1, step 8, Add Makeup to RWST as Necessary – implement Appendix M, while continuing with this procedure
EOP ECA-1.1 Appendix M will direct operators to establish makeup to the RWST from either of two methods:
Makeup to the RWST from the spent fuel pool (preferred); or
Makeup to the RWST using the blender. Operators initially align makeup to the RWST from the spent fuel pool. Once the available spent fuel pool inventory is depleted, operators continue in the Appendix M instructions to makeup the RWST using the blender. Initial makeup to the RWST from the spent fuel pool, as presented at the Regulatory Conference, is initiated 30 minutes after reaching 33% RWST level and concludes when available spent fuel pool inventory is depleted 2.78 hours later. See Calculation MAAP 16-03, Revision 0. PG&E performed and provided analysis using both methods of RWST makeup specified by Appendix M on December 6, 2016. The assessment using both methods of makeup directed by EOP ECA-1.1 initiated makeup 30 minutes after reaching 33% RWST level and concluded when the RWST reached 4% level 6.51 hours later. See Calculation MAAP 16-03, Revision 1 (Reference 5). Although a note in Appendix M states that inventory for makeup to the RWST may be available from the liquid holdup tanks, its use requires additional sampling, evaluation, and TSC approval, then alignment per Plant Operating Procedure OP B-1A:XVI. Accordingly, it would only be pursued after the two EOP-directed makeup alignments listed above were completed. </td></tr>
<tr><td>T = 9 mins</td><td>Operators continue in the procedure while other operators pursue Appendix M as described above (time based on observed simulator performance)</td></tr>
<tr><td></td><td>EOP ECA-1.1, step 9, operators would verify a heat sink exists with the steam generators
EOP ECA-1.1 steps 10 and 11, operators would start a cooldown by dumping steam from the secondary plant.</td></tr>
</table>

Time after 33% RWST – Control Room-Directed Operator Actions: Procedure and Steps	
T = 12 mins	**Reduce ECCS flow to one train (time based on observed simulator performance)**
	• EOP ECA-1.1, step 13, ESTABLISH One Train of Safety Injection (SI) Flow *This step ensures only one ECCS CCP and one SIP are running. There are no required conditions prior to securing one train (i.e., 70°F subcooling is not required before turning off the pumps). PG&E modeled the time of securing one train of ECCS as 12 minutes following 33% RWST level.*
T = 21 mins	**Reduce ECCS flow to one pump (time based on observed simulator performance)**
	• EOP ECA-1.1, step 16.b, ESTABLISH One Train of SI Flow – RCS Subcooling based on core exit thermocouples: GREATER THAN 70°F (YI-31 or Appendix C) • EOP ECA-1.1, response not obtained for step 16.b, Establish minimum SI flow to remove decay heat as follows: 1) Determine minimum ECCS flow from Appendix G. 2) Establish minimum ECCS flow: • Manually operate pumps as necessary • GO TO step 23 (Page 12). *ECCS minimum flow per Appendix G at almost 3 hours after reactor trip is less than 300 gpm. Accordingly, operators secure the operating SI pump and leave only one ECCS CCP operating. PG&E modeled the time of securing one SI pump as 12 minutes after reaching 33% RWST level.* *With the additional action to make up to the RCS via normal charging injection after RWST depletion, the modeling simplification above (the time when ECCS flow reduction occurs) has an insignificant impact to the total time available for recovery. A sensitivity was performed using MAAP (Reference 6) with the action to reduce ECCS Flow from two Trains of SIP and CCP to only one CCP occurring at 21 minutes after RWST reaches 33% level, and the overall recovery time available was 14.24 hours. The overall recovery time when ECCS flow reduction occurs at 12 minutes after RWST reaches 33% level is 14.27 hours. This is inconsequential to the final ΔCDF calculation.*

Time after 33% RWST – Control Room-Directed Operator Actions: Procedure and Steps	
T = 6.51 hrs	**RWST = 4% level (time based on analysis)**
	• EOP ECA-1.1, step 30, STOP all pumps taking suction from the RWST • EOP ECA-1.1, step 31, TRY To Add Makeup To RCS From Alternate Source: o Makeup to RCS from VCT through Normal Charging Line, IMPLEMENT Appendix W
T = 7.01 hrs	**Start RCS Makeup from VCT through Normal Charging Line (time based on operator experience)**
	• EOP ECA-1.1, Appendix W *Appendix W directs operators to align the Volume Control Tank makeup system, align the ECCS CCP suction to the VCT and initiate normal makeup to the RCS. PG&E modeled this normal charging at maximum makeup flow of 130 gpm based on the maximum available flow from the system under this alignment, allowing 30 minutes for operators to perform the alignment after reaching 4% RWST level. While this makeup rate is not sufficient to match the required decay heat load, it does significantly extend the time to core damage.*
T = 14.27 hrs	**Core damage (time based on analysis)**
	Accounting ONLY for the actions taken by operators as explicitly directed by Control Room EOPs, the analysis concludes that approximately 14 hours total recovery time was available to complete opening Valve SI-2-8982B.

Figure 1 – Event Timeline



ATTACHMENT 2

The following table demonstrates the timelines and sequence of actions to demonstrate TSC/OSC management of two parallel electrical and mechanical recovery actions and incorporates the time necessary to ensure that actions taken are performed safely and in accordance with procedural requirements.

Table 2: Timelines for Parallel Recovery Actions[a]

Electrical Recovery Action			Mechanical Recovery Action		
Using OP O-22	**Action Time**	**Total Time**	**Using OP O-9**	**Action Time**	**Total Time**
Pre-job brief in OSC/TSC	15 min	00:15	Pre-job brief in OSC/TSC	15 min	00:15
Gather tools, transit to area, dress out in Arc Flash suit	10 min	00:25			
Open breaker and panel; establish telephone communication with Control Room; close breaker, depress thermal overload reset; Control Room Operator attempts to open, returns switch to neutral position	10 min	00:35	Transit into RCA and tool room; gather tools, transit to vault area in RCA; operator dons PCs during this time	20 min	00:35
			Setup tools, unbolt vault cover (using power driver), open hinged vault cover, check rad levels and sample confined space air quality	15 min	00:50
Recognize no labelling, summon TSC electrician assistance and perform pre-job brief, obtain and review electrical print, report to switchgear cabinet for open contactor positive ID	20 min	00:55			

Electrical Recovery Action			Mechanical Recovery Action		
Using OP O-22	**Action Time**	**Total Time**	**Using OP O-9**	**Action Time**	**Total Time**
Depress contactor and open valve	5 min	1:00	Entry brief; confined space permit review; external operator review of work location	10 min	01:00
If valve does not open, get permission to troubleshoot from OSC	3 min	1:03			
Reset thermal overload	1 min	1:04			
Open circuit breaker and inform TSC	1 min	1:05	TSC-directed Delay waiting for electrical breaker to be opened after electrical recovery fails	5 min	1:05
Perform troubleshooting activities per OP O-22			TSC communicates valve breaker open[b]	4 min	1:09
Total Time to Complete Electrical Recovery 1:00 hours			Enter vault and transit to valve	1 min	1:10
			Operate valve	5 min	1:15
			Total Time to Complete Mechanical Recovery 1:15 hours		

Notes:

[a] This timeline follows a 10-minute period after initial indication of valve failure and a 30-minute period for diagnosis and development of written recovery actions applying Rapid Team Dispatch per EP EF-2. As a result, these actions begin approximately 40 minutes after 33 percent RWST level is reached.

[b] OP O-9 clearance hang would be relaxed per OSC admin requirement relaxation authority.

ATTACHMENT 3

The following table summarizes the effects of revising the significance determination in response to the more significant areas of the appeal.

Table 3: Summary of ΔCDF Changes

Basis No.	Subject of Appeal	Description of Model Change	Reduction from FSD ΔCDF	Updated ΔCDF
1	NUREG-1829 Data	Only Use 25-year LOCA Frequency Data	>1.5E-07	<1.2E-06
2, 3	Superseded Procedure For Recovery Actions	SLOCA/MLOCA Recovery PSF Changes	>5.5E-07	<7.5E-07
4	Use Incomplete Procedure PSF for Mechanical Recovery	Use Available Procedure PSF for Mechanical Recovery	>5E-07	<8E-07
5	Additional Time for SLOCAs	SLOCA Recovery PSF Change	>3.5E-07	<1E-06
TOTAL UPDATED ΔCDF <6E-07 (Note 1)				

Note 1: Total Updated ΔCDF includes the cumulative effect of the impacts of Basis No. 1 through 5.