Date of Issuance:
December 10, 2025

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SAFETY POLICY DIVISION **Resolution SPD-37**
December 4, 2025

R E S O L U T I O N

RESOLUTION SPD-37 Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations.

PROPOSED OUTCOME:
Refines the *SB 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations,* previously adopted in Resolution SPD-15, issued March 8, 2024. Aligns the Commission's program with the recently adopted SB 884 *10-Year Electrical Undergrounding Plan Guidelines* of the Office of Energy Infrastructure Safety.

SAFETY CONSIDERATIONS:
Reduce utility caused wildfires and increase reliability through the adopted expedited utility distribution infrastructure undergrounding program.

COSTS:
None; no costs are approved by this resolution. Any program costs will be considered and conditionally approved through subsequent SB 884 Applications submitted by participating utilities, an audit process, and a just and reasonable cost review process for certain costs.

1. SUMMARY

This Resolution builds on earlier Resolution SPD-15 implementing Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), codified at Public Utilities Code (PU Code) Section 8388.5.[1] The Commission approved Resolution SPD-15, issued March 8, 2024, adopting the *Senate Bill (SB) 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations* (SPD-15 Guidelines) that addressed the process and requirements for Commission review of any

[1] PU Code Section 8388.5 https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=8388.5.&lawCode=PUC.

regulated large electrical corporation's 10-year distribution infrastructure undergrounding plan (hereafter known as the Electric Undergrounding Plan (EUP) or Plan) application and conditional approval or denial of related costs. The Commission noted in Resolution SPD-15 that additional issues remained to be resolved.

This second Resolution adopts the following outcomes:

1. Updates and adds Phase 2 Application requirements that aid the Commission in developing a record to determine whether cost recovery is reasonable.
2. Explains a process for ensuring costs recovered via the memorandum account adopted in Resolution SPD-15 are capped and not excessive.
3. Adopts primary and secondary objectives for an audit of any costs recorded to the one-way balancing account adopted in Resolution SPD-15.
4. Establishes a joint Phase 1 Application[2] process to resolve issues not addressed in this Resolution, including how Cost-Benefit Ratios (CBR)[3] must be calculated; whether large electrical corporations' proposed audit methodology is adequate; and whether any additional conditions should be placed on what costs are allowed to be recovered through the one-way balancing account adopted in Resolution SPD-15.

2. BACKGROUND

The SPD-15 Guidelines set forth a three-phased process for implementation of SB 884's requirements. The first phase requires the EUP to be reviewed and approved or denied by the Office of Infrastructure Safety (Energy Safety) prior to review by the Commission (Phase 1). In the second phase (Phase 2), the Commission reviews and may conditionally approve or deny an application for the EUP's costs (Phase 2 Application). Any conditional approval will authorize the creation of a one-way balancing account to potentially recover plan costs contingent on the satisfaction of conditions placed on approval. If the Commission conditionally approves cost recovery in the one-way

[2] SPD-15 recognizes there is a "Phase 1" process before Energy Safety; this resolution requires a new application process before the CPUC that is referred to as "Phase 1 Application."

[3] CBR is calculated by dividing the dollar value of Total Mitigation Benefit by the Present Value of the Capital Costs. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3. In the Phase 4 Decision of the RDF Proceeding, the Commission clarified that Cost-Benefit Ratios (CBR) should now be referred to as Benefit-Cost Ratios (BCR) to ameliorate possible confusion. See D.25-08-032, CoL 39. While CBR has not be adjusted in the Resolution, any reference to CBR in this Resolution is synonymous with BCR.

balancing account, the Commission will also authorize the large electrical corporation to establish a memorandum account to potentially recover any EUP costs that fail to meet the conditions set forth by the Commission. Resolution SPD-15 also established that the one-way balancing account requires an audit, and if any costs recorded to the account do not meet conditions imposed in the Commission's decision on the Phase 2 Application (Phase 2 Decision), such costs may be subject to refund to ratepayers. The third phase (Phase 3) consists of EUP implementation, progress reporting, and ongoing monitoring and review. Any EUP costs recorded in the authorized memorandum account must be submitted to the Commission for review of justness and reasonableness in separate applications (Phase 3 Application) prior to recovery in rates.

To implement the first phase, Energy Safety issued its *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*) on February 20, 2025. Among other reasons, this Resolution updates and refines the SPD-15 Guidelines in consideration of the *Energy Safety Guidelines*. This Resolution directs staff to conform the SPD-15 Guidelines to the discussion herein.

2.1 SB 884 Background

SB 884, effective January 1, 2023, requires the Commission to establish an expedited utility distribution infrastructure undergrounding program in Tier 2 and Tier 3 High Fire-Threat District (HFTD) areas and in wildfire rebuild areas for the state's large electrical corporations. The statute authorizes, but does not require, utilities with 250,000 or more customer accounts (large electrical corporations) to participate.

To begin the process, each participating large electrical corporation submits a 10-year EUP to Energy Safety for review. Energy Safety must approve or deny the EUP within nine months of filing. If approved by Energy Safety, the large electrical corporation must then submit to the Commission, within 60 days of Energy Safety's approval, a copy of the approved EUP and Phase 2 Application requesting conditional approval of the EUP's costs. The Commission must approve or deny the Phase 2 Application within nine months of submission.

Pursuant to PU Code Section 8388.5(f), if the EUP is approved by Energy Safety and the Commission, the large electrical corporation shall do all the following:

> (1) Every six months, file a progress report with [Energy Safety] and the commission. The large electrical corporation and Energy Safety shall publish these progress reports on their respective internet websites.
> (2) Include ongoing work plans and progress in annual wildfire mitigation plan filings.

(3) Hire an independent monitor, selected by [Energy Safety], to review and assess the large electrical corporation's compliance with its plan and submit a report with Energy Safety each December 1 over the course of the plan.

Under PU Code Section 8388.5(j), "[e]ach large electrical corporation participating in the program shall apply for available federal, state, and other nonratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers."

Finally, PU Code Section 8388.5(i)(2) provides that "[t]he commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan."

2.2 SPD-15 Guidelines

The SPD-15 Guidelines establish several key elements of the SB 884 program. These elements include the requirements for Phase 2 Application submittal; minimum conditions for conditional approval (Phase 2 Conditions); accounting structures for tracking and recording costs related to an EUP; the concept of an audit and potential refund to ratepayers for costs recorded in an authorized one-way balancing account; the structure and timing of any applications submitted pursuant to Phase 3 of the program; information to be included in progress reports; and identification of a preliminary dataset that must be included in a Phase 2 Application. Resolution SPD-15 deferred finalizing several of these concepts, including the audit of the one-way balancing account, progress report filings, and the *SB 884 Project List Data Requirements Guidelines*, to a later Commission decision or order, and this Resolution acts on those items and others that have arisen since SPD-15's adoption.

2.3 Audit of Balancing Account

Resolution SPD-15 provided that "[t]he details of th[e] [balancing account] audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a future decision or order."[4] This Resolution identifies primary and secondary objectives for the audit process and requires large electrical corporations to propose a methodology for conducting the audit in a joint Phase 1 Application.

2.4 Progress Reports

[4] SPD-15 at 15.

The Commission adopted Resolution SPD-15 before Energy Safety adopted its own Guidelines. The SPD-15 Guidelines anticipated that the details of six-month progress report filings and the data filing requirements, included as Appendix 1 of the SPD-15 Guidelines, would require future refinement after finalization of the *Energy Safety Guidelines* and consultation amongst the agencies. The *SB 884 Project Lists Data Requirements-Preliminary* were refined and revised following a series of Technical Working Group (TWG) meetings,[5] as authorized by SPD-15,[6] and are included with this Resolution as the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*.

2.5 EUP Detail Needed for Determination of Cost Recovery

Detailed information on specific undergrounding projects is essential for the Commission and stakeholders to assess and determine the appropriate Phase 2 Conditions, which are used to determine whether balancing account cost recovery for EUP projects is appropriate. This Resolution expands on the process and requirements in Resolution SPD-15 for such cost recovery.

After the Commission adopted Resolution SPD-15, on February 20, 2025, Energy Safety adopted Guidelines setting forth the details of the EUP approval process that were not yet developed at the time of SPD-15's adoption. The *Energy Safety Guidelines* detail the requirements and process for execution of Phase 1 of the SB 884 program. Under the *Energy Safety Guidelines*, it is likely the vast majority of undergrounding projects in the approved EUP will only be preliminarily scoped, as explained below, and will be subject to substantive change following approval of the EUP. This scoping and project selection process is implemented through Energy Safety's "Project Acceptance Framework" approach.

Energy Safety's Project Acceptance Framework approach for its review and approval of EUPs is a multi-step process that a large electrical corporation must establish and use to identify and select undergrounding projects for construction through its EUP.[7] The Project Acceptance Framework contains four increasingly specific screening criteria, which allow a large electrical corporation to filter all potential undergrounding projects down to a list of prioritized undergrounding projects at the final fourth screen. A brief overview of Energy Safety's Project Acceptance Framework is provided below.[8]

[5] Presentation materials and recordings of the Technical Working Group meetings are available on the Commission's SB 884 webpage at: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

[6] SPD-15, Ordering Paragraph 3 at 21.

[7] *Energy Safety Guidelines* at 11.

[8] For a detailed explanation of the Project Acceptance Framework, see *Energy Safety Guidelines* at 11-24.

- **Screen 1 – Circuit Segment Eligibility:** The large electrical corporation must assess all of its circuit segments[9] to determine EUP eligibility based on locational constraints (location in Tier 2 or Tier 3 HFTD areas), and then determine whether each of these circuit segments meet specific project-level thresholds (whether the individual project's risk score shows a required level of risk establishing the need for mitigation). Circuit segments that meet both locational and project-level requirements are considered to "pass" Screen 1 and are included in an "Eligible Circuit Segments List" (the output of Screen 1).
- **Screen 2 – Project Information and Alternative Mitigation Comparison:** The large electrical corporation must confirm whether sufficient information is available on a circuit segment to establish a preliminary scoping. It must conduct cost-benefit analysis comparisons of undergrounding to two separate alternative mitigations to determine which projects from the Eligible Circuit Segments List can be treated as undergrounding projects. Circuit segments that meet the informational requirements and present a comparison of the project to at least two alternative mitigations are considered to "pass" Screen 2 and are include in an "Undergrounding Projects List" (the output of Screen 2).
- **Screen 3 – Project Risk Analysis:** The large electrical corporation must evaluate each individual undergrounding project that is included in the "Undergrounding Projects List" according to the information obtained through the project development process (the "scoping phase").[10] In Screen 3, the large electrical corporation must determine if the undergrounding project meets expected wildfire risk reduction and reliability improvements of the "Plan Mitigation Objective."[11] The large electrical corporation also compares "Key Decision-Making Metrics" (KDMMs) in Screen 3 to identify fixed areas where undergrounding work will occur (identified as "Confirmed Project Polygons").[12]

---

[9] In the *Energy Safety Guidelines*, all potential undergrounding projects are assessed at "circuit segment" granularity. "Circuit segment" is defined as "an isolatable circuit segment" (See *Energy Safety Guidelines* at A-1).

[10] The scoping phase typically identifies the size and timeline of the project. It also determines the feasibility of construction and possible timing of execution of an undergrounding project. While Energy Safety in some places refers to this as the "scoping process" or "project scoping phase", this resolution uses the term "scoping phase" throughout.

[11] The Plan Mitigation Objective is the total amount of change in risk (wildfire and reliability) that is necessary to meet the requirement of section 8388.5(d)(2). For discussion of the Plan Mitigation Objective see *Energy Safety Guidelines* at 3-5.

[12] Energy Safety defines a Confirmed Project Polygon as "a special boundary generated at the beginning of Screen 3 that encompasses the entire Eligible Circuit Segment on which the Undergrounding Project is defined, except any sections already contained in another Confirmed Project Polygon." *Energy Safety*

Undergrounding projects that meet the informational requirements for the scoping process, demonstrate contribution to the Plan Mitigation Objective, and present a comparison of KDMMs between the undergrounding project and alternative mitigations are considered to "pass" Screen 3 and are included in a "Confirmed Projects List" (the output of Screen 3).

- **Screen 4 – Project Prioritization:** The EUP must set forth a means of prioritization and its definition for each of the factors in PU Code Section 8388.5(c)(2) (wildfire risk reduction, public safety, cost efficiency and reliability benefits) and conduct a comparison of the costs, benefits, and CBR for the design variations that were used in Screen 3.[13] After taking the Confirmed Project List (the output of Screen 3), and applying the means of prioritization established in Screen 4, the large electrical corporation is left with the "Prioritized Projects List" (the output of Screen 4).

The *Energy Safety Guidelines* permit an EUP to be filed by a large electrical corporation once 25 undergrounding projects have passed through Screen 3 of the Project Acceptance Framework.[14] This requirement does not preclude a large electrical corporation from filing an EUP that has more than 25 undergrounding projects that have passed through Screen 3. However, the 10-year duration of EUPs suggests that, at the time a Phase 2 Application is filed with the Commission, only a small fraction of undergrounding projects that may be constructed as part of the EUP will have progressed through at least Screen 3.[15] Further, a large electrical corporation will not be required to obtain Energy Safety approval of undergrounding projects it later intends to construct. Rather, as set forth below, the large electrical corporation will provide detail about new projects in progress reports. This Resolution addresses how the Commission will assess the appropriateness of cost recovery for such projects.

PU Code Section 8388.5(c)(2) requires, in part, that an EUP filing identify "the undergrounding projects that will be constructed as part of the program.…" With the exception of the 25 projects that are required to pass through Screen 3, the *Energy Safety Guidelines* find that this requirement is satisfied when the projects in the EUP have

---

Guidelines at A-1. KDMMs are up to 12 top-level metrics that the large electrical corporation proposes to use to evaluate the efficacy of an Undergrounding Project. See *Energy Safety Guidelines* at 30-32.

[13] The CBR calculation must follow the guidelines found in D.24-05-064 Appendix A or the most recent decision from the risk-based decision-making framework (RDF) Proceeding (R.20-07-013) or its successor proceeding.

[14] *Energy Safety Guidelines* at 12.

[15] PG&E in response to Energy Safety-DR-EUP-24-06 Question 1 states that the PG&E scoping team estimates it will complete an average of thirty projects per quarter, which would potentially result in approximately 1,200 projects over the ten years of the EUP.

passed Screen 2 (are included in the "Undergrounding Projects List").[16] As explained above, Screen 2 is an early step in the scoping process for an undergrounding project.

The time for approval of an EUP is short. PU Code Section 8388.5(d)(2) requires that Energy Safety approve or deny an EUP within nine months of its filing. Furthermore, PU Code Section 8388.5(e)(1) requires that a large electrical corporation must file its Phase 2 Application with the Commission within 60 days of Energy Safety approving its EUP. Because significant changes can be made to the economic metrics (total costs, unit costs, and cost benefit ratios) of an undergrounding project as it is more accurately scoped in Screens 3 and 4, the large majority of forecasted data available to the Commission at the time a Phase 2 Application is filed, and upon which its EUP cost approval conditions in the Phase 2 Decision will be based, will not be sufficiently precise to provide the intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15. Accordingly, this Resolution requires a future Phase 1 Application process to close any such gaps and ensure the Commission has the information essential to determining the appropriateness of cost recovery.

2.6 Stakeholders Participating in SB 884 Program Development

The large electrical corporations eligible to seek cost recovery in this program are: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE). All the large electrical corporations have been participating in the development and refinement of the guidelines. PG&E and SDG&E have confirmed their intent to file EUPs.[17]

Other stakeholders that have participated in the Commission's process to implement SB 884 include the Commission's Public Advocates Office (Cal Advocates); The Utility Reform Network (TURN); Mussey Grade Road Alliance (MGRA); California Farm Bureau (CFB); Green Power Institute (GPI); Coalition of California Utility Employees (CUE); AT&T California/California Broadband and Video Association/Crown Castle Fiber, LLC/Sonic Telecom, LLC (collectively, Communication Providers); ExteNet Systems, LLC/ExteNet Systems (California) LLC (ExteNet); DISH Wireless LLC; and INCOMPAS.

2.7 Procedural History

[16] *Energy Safety Guidelines* at 12.

[17] For SDG&E see response to Data Request No. SPD-SDGE-SB884-006, available at https://www.sdge.com/sites/default/files/regulatory/Data%20Request%20SPD-SDGE-SB884-006_Response.pdf. For PG&E see A.25-05-009, Exhibit (PG&E-4) Chapters 1-9 at 2-13.

A chronological history of events beginning with the Commission's adoption of the SPD-15 Guidelines and continuing to the present is as follows:

- March 8, 2024 – Commission issued Resolution SPD-15, "SB 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations."
- October 14, 2024 – Safety Policy Division (SPD) issued "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" for stakeholder comment.
- November 12, 2024 – Responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" received from stakeholders.
- February 20, 2025 – Energy Safety issued its "10-year Electrical Undergrounding Plan Guidelines."
- April 8, 2025 – SPD workshop to discuss potential modifications to the SPD-15 Guidelines following publication of the *Energy Safety Guidelines*.
- April 11, 2025 – SPD issued "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" soliciting comments on topics discussed at the April 8, 2025, workshop.
- April 25, 2025 – Responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" received from stakeholders.
- May 20, 2025 – SPD issued "Staff Report on SB-884 Projects List Data Requirements Guideline" providing background, purpose, and details of proposed changes to SB 884 data requirements and providing a set of "Technical Working Group Questions" to prompt discussion for upcoming TWG meetings.
- June 3, 2025 - SPD TWG meeting #1 on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
- June 10, 2025 - SPD TWG meeting #2 on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
- June 24, 2025 - SPD TWG meeting #3 to discuss the Interruption Cost Estimate Calculator (ICE 2.0).
- June 24, 2025 – Responses to "Technical Working Group Questions" received from stakeholders.
- July 24, 2025 – SPD published the Revised *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template.*

2.8 Organization of Resolution

This Resolution builds on the SPD-15 Guidelines, focusing on the following five program elements**:**

1. Additional Phase 2 Application requirements;

2. Memorandum account limitations;

3. Balancing account audits;

4. CBR guidance; and

5. Phase 1 Application process.

These elements are discussed in further detail in the Discussion section below, along with recommendations and comments from stakeholders.

3. DISCUSSION

This Resolution introduces refinements to the guidelines to: (1) align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines*, (2) clarify the procedure for an audit as anticipated in Resolution SPD-15, (3) add new data reporting requirements pursuant to SPD-15's directive, and (4) provide additional information needed to ensure the Commission can effectively assess cost recovery for EUPs.

Between the adoption of the SPD-15 Guidelines issued March 8, 2024, and the *Energy Safety Guidelines* on February 20, 2025, Commission Staff issued and received responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" on November 12, 2024, which provided additional information and insight into potential future refinements of the guidelines.[18] Following the adoption of the *Energy Safety Guidelines*, Commission Staff hosted a workshop on April 8, 2025, and issued and received responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" on April 25, 2025. Prior to the commencement of TWG meetings, authorized by SPD-15 to refine data requirements for the Commission's SB 884 program, Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" on May 20, 2025, which included a set of "Technical Working Group Questions." Commission Staff then hosted a series of three TWG meetings in June 2025, and accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the adoption of the *Energy Safety Guidelines*, informs the *CPUC Guidelines* presented in this Resolution. In addition to the changes that are described in the following sections, changes have also been made to the *CPUC Guidelines* to reflect that the version of the *CPUC Guidelines* adopted in SPD-37 has undergone a process of aligning the *CPUC Guidelines* with the *Energy Safety Guidelines*.

[18] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-consolidated-responses-to-informal-questions_111224.pdf

SB 884 instituted requirements for the Commission to create a novel program that expedites the review and approval of EUPs and conditional approval of their costs. An inherent challenge with this program is balancing the expedited nature of reviewing an unprecedented volume, cost, and duration of electrical distribution infrastructure hardening via undergrounding to reduce the ongoing threat of utility-involved wildfires with growing pressure on electric rates. The expedited EUP program adopted by SPD-15 and refined by SPD-37 provides a new venue for large electrical corporations to take a long-term approach to addressing growing wildfire risk through undergrounding mitigations.

To clarify the cost recovery process and establish a means to achieve the intended outcomes of SB 884, the SPD-15 Guidelines used the "conditional approval" provision in PU Code Section 8388.5(e)(1) to establish Phase 2 Conditions. The Phase 2 Conditions are a central feature of the guidelines. These conditions provide direction to large electrical corporations on the amount of EUP costs that will be authorized to recover in rates via the balancing account, while ensuring ratepayer interests are protected. The conditions provide regulatory clarity and certainty for large electrical corporations while ensuring EUP costs borne by ratepayers are just and reasonable. Under the SPD-15 framework, an audit and refund process is necessary for the one-way balancing account. The large electrical corporation initially asserts that EUP project costs have met the Phase 2 Conditions upon recording in the one-way balancing account. It is only during the audit process that the Commission verifies whether the Phase 2 Conditions were met (Primary Objectives).

Following adoption of the *Energy Safety Guidelines* and consideration of stakeholder input, the Commission provides more detail in this Resolution on the process for large electrical corporations to record EUP costs in the balancing account and seek to recover EUP costs in the memorandum account. The process is intended to further strengthen program oversight, bolster ratepayer protections, increase rate stability, and improve the efficiency of the cost recovery process by clarifying the objectives of the EUP Audit discussed in Section 3.3 of this Resolution.

As established in the SPD-15 Guidelines, Phase 2 Conditions are predicated on information presented by large electrical corporations in Phase 2 Applications. The Phase 2 Conditions establish the parameters that govern cost recovery via the one-way balancing account and must reflect the most accurate and up-to-date EUP project related information. However, much of the project-specific information received at the time a Phase 2 Application is filed is expected to lack refined scoping information. Projects other than those that pass Screen 3 at the time of an EUP submittal to Energy Safety will only include the output of Screen 2 of the *Energy Safety Guidelines*. The Commission adopts the requirements below to ensure the necessary information for Commission review accompanies all projects, including those that have not yet passed Screen 3 at the time of a Phase 2 Application submittal.

This Resolution adopts a change to one existing Phase 2 Application requirement (Existing Application Requirement No. 11) and adds five new Phase 2 Application requirements. This Resolution also adopts a cap on the total cumulative costs recoverable via the memorandum account, provides the process and details for the EUP Audit, and adopts a Phase 1 Application process for determining how CBR calculations required for this program should be performed, whether large electrical corporations' proposed audit methodology is adequate, and whether any additional conditions should be placed on what costs are allowed to be recovered through the one-way balancing account adopted in Resolution SPD-15.

3.1 Additional Application Requirements

Following the adoption of the *Energy Safety Guidelines*, the Commission received input from stakeholders during the April 8, 2025, workshop and written responses to questions soliciting input on potential additional Phase 2 Application requirements on November 12, 2024, and April 25, 2025. The Commission now determines that additional Phase 2 Application requirements are necessary to: (1) align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines*, (2) add new data reporting requirements pursuant to SPD-15's directive, and (3) provide additional information needed to ensure the Commission can effectively assess cost recovery for EUPs.

The SPD-15 Guidelines established twenty Phase 2 Application requirements.[19] Staff presented potential additional Phase 2 Application requirements during the above noted workshops and review of feedback from stakeholders. Considering the workshop and stakeholder feedback the Commission adopts the following Phase 2 Application requirements:[20]

1. Existing Application Requirement No. 11 is revised as follows: "For each project

[19] Resolution SPD-15, Attachment 1 at 6.

[20] The new Application requirements adopted by this Resolution are not necessarily incorporated sequentially in the *CPUC Guidelines*, as reflected in the redlined version of the *CPUC Guidelines* included as Attachment B to this Resolution.

included in the Application, the large electrical corporation shall provide, at a minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file[21] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission."

2. First New Application Requirement: "The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*."
3. Second New Application Requirement: "The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application."
    a. "The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[22]"
4. Third New Application Requirement: "The Application shall include:
    a. The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b. The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety."
5. Fourth New Application Requirement: "The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division oversight and a non-disclosure agreement in place,[23] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[24]"
6. Fifth New Application Requirement: "The Application shall only include undergrounding projects that have a forecasted CBR greater than or equal to 1."

---

[21] See Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 1, Rule 1.3(b) for complete submission requirements of pdf files.

[22] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

[23] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[24] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

Resolution SPD-15 acknowledged the project data template, attached to SPD-15 as Appendix 1 of the SPD-15 Guidelines, was preliminary. The Commission directed Staff to refine, update, and finalize Appendix 1 following a series of TWG meetings after the publication of the *Energy Safety Guidelines*.[25] Staff has completed this process, and the data requirements in the *SB 884 Project List Data Requirements Guidelines* are no longer preliminary. Thus, Existing Application Requirement No. 11 is updated to include the instruction for the large electrical corporation to provide the most recent data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Phase 2 Application submission.

SPD-15 authorized SPD to reconcile the data template in Appendix 1 of the SPD-15 Guidelines within one month of a final TWG meeting. The *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* were issued by SPD on July 24, 2025. This resolution authorizes SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one TWG meeting about said updates and changes without the need for a Commission Decision or Staff Resolution. The large electrical corporations must complete the *SB 884 Project List Data Template*[26] according to the requirements found in the *SB 884 Project List Data Requirements Guidelines* and submit the completed *SB 884 Project List Data Template* with their Phase 2 Application and six-month progress reports.

The First New Application Requirement reflects the process set forth in the *Energy Safety Guidelines* and makes explicit that a large electrical corporation is required to provide specific information required by Energy Safety when submitting its Phase 2 Application. This includes the addition of the "Undergrounding Projects List" that is an output from Screen 2 of the *Energy Safety Guidelines*, adopted after the issuance of SPD-15.

The *Energy Safety Guidelines* provide that, "[i]f a Circuit Segment has portions both within and outside of a Tier 2 or 3 HFTD, each span crossing the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may be considered for undergrounding."[27] To ensure consistency between the *Energy Safety*

---

[25] SPD-15, Ordering Paragraph 3 at 21.

[26] The *SB 884 Project List Data Template* is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-template-clean-version_2.xlsx.

[27] *Energy Safety Guidelines* at 16.

Guidelines and the *CPUC Guidelines*, the Second New Application Requirement requires a large electrical corporation to explain why undergrounding work outside of Tier 2 or 3 HFTD areas is necessary to meet the purpose of SB 884. The sub-requirement of the Second New Application Requirement states all undergrounding projects in the Application must be designated as an "In-Area" circuit segment located inside the Tier 2 HFTD, Tier 3 HFTD, or a wildfire rebuild area, and align with the in-area requirement associated with Screen 1 of the *Energy Safety Guidelines*.[28]

Regarding the Third New Application Requirement, the *Energy Safety Guidelines* created the concept of KDMMs, defined "to be the collection of top-level metrics that the [l]arge [e]lectrical [c]orporation proposes to use to evaluate the efficacy of an [u]ndergrounding [p]roject."[29] Large electrical corporations must submit KDMM data with an EUP[30] and update the KDMM data in the six-month progress reports, including any reports submitted during the nine months while Energy Safety is reviewing the EUP.[31] Given this process, it is reasonable to require a large electrical corporation to include any updated KDMM data provided in its six-month progress reports submitted while its EUP is under review with its Phase 2 Application.

Staff solicited input from stakeholders on the inclusion of KDMM data in a Phase 2 Application.[32] TURN supported the Commission's inclusion of KDMMs,[33] while PG&E and SDG&E argued that the Commission would already have access to KDMM data through the EUP.[34] However, PG&E agreed to "provide the most recent six-month progress report which will include the most recent KDMM information"[35] when submitting its Phase 2 Application. It is not sufficient to rely on data in the record of another state agency; large electrical corporations must provide all required information to the Commission and serve it on stakeholders.

---

[28] *Energy Safety Guidelines* at 12.
[29] *Energy Safety Guidelines* at 30.
[30] *Energy Safety Guidelines* at 26.
[31] *Energy Safety Guidelines* at 25.
[32] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6.
[33] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 16.
[34] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 7; and SDG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 5.
[35] PG&E response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question A.6 at 7.

The Fourth New Application Requirement is added to ensure that Phase 2 Applications present a detailed and accurate forecast of the large electrical corporation's revenue requirement for the 10-year period of the EUP. The SPD-15 Guidelines already require the large electrical corporation to provide a "best estimate, including all underlying assumptions, of the proposed annual revenue requirements."[36] In its November 12, 2024, response to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines," PG&E stated that an RO Model should be used to generate revenue requirements in a Phase 2 Application.[37] This Resolution specifies how a revenue requirement must be calculated via an RO Model.

The Fifth New Application Requirement is added to ensure that undergrounding projects presented in a Phase 2 Application provide a cost-efficient overall benefit to ratepayers. As discussed in SPD-15 and the SPD-15 Guidelines, CBR is calculated by dividing the monetized benefits of a particular mitigation by its costs. A CBR of 1.0 is considered a breakeven point, where the benefits of a particular mitigation are equal to its costs. Conversely, CBRs less than 1.0 indicate that the costs of a particular mitigation exceed its benefits. Allowing undergrounding projects that have forecasted CBRs below 1.0 to be included in a Phase 2 Application would be unreasonable.

Staff solicited input from stakeholders on this topic in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines."[38] PG&E, the largest electrical corporation eligible to file an EUP, stated its support for a requirement for undergrounding projects presented in a Phase 2 Application to have a forecasted CBR greater than or equal to 1.0 "because that is indicative of a good investment."[39] By adding this requirement, the Commission does not intend to imply that all projects submitted in a Phase 2 Application with a forecasted CBR greater than or equal to 1.0 are necessarily a good investment.

---

[36] The need for a forecasted revenue requirement is listed in Application Requirement #3 in the *CPUC Guidelines* at 7.
[37] PG&E Informal Responses to Questions, November 12, 2024, at 3.
[38] See "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question B.3.a, published on April 11, 2025.
[39] PG&E's response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," filed on April 25, 2025, at 9.

3.2 Memorandum Account Cap

The Commission established a memorandum account in Resolution SPD-15 in light of the inherent uncertainties associated with forecasting 10 years of undergrounding projects in an EUP. The memorandum account was intended for amounts above the one-way balancing account cost cap, and that review would "determin[e] whether the costs recorded in the memorandum account were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable."[40] The Commission noted that allowing a memorandum account "reasonably recognizes that there are significant uncertainties in undergrounding electrical distribution equipment that are likely to grow over a 10-year period. Further, this provision creates a pathway for a large electrical corporation to demonstrate that such costs are just and reasonable, and incremental."[41] However, the Commission did not state or intend for the memorandum account to be a limitless repository for costs from projects that do not meet the goals of SB 884 or prudent wildfire mitigation.

The vast majority of undergrounding projects associated with the approved EUP will likely not be completely scoped until a project successfully passes Screen 3 and Screen 4 of the *Energy Safety Guidelines*. Thus, a Phase 2 Application will likely contain projects that lack a refined scope or detail where construction is scheduled later in the 10-year Plan cycle.

The Commission must prevent the memorandum account from becoming a structural incentive to continuing work on imprudent projects. A cost-cap on amounts recovered via the memorandum account will improve both ratepayer and shareholder certainty and avoid potential volatility in the SB 884 program. Utilities record costs in memorandum accounts as they are incurred, and costs are subject to reasonableness review before recovery in rates. Because of the elapse of time between recording and recovery, utilities may accumulate large balances with uncertain recovery. Allowing uncapped spending could create a significant amount of risk to both ratepayers and shareholders.

To address this issue, Staff proposed a maximum total cost cap for the memorandum account at the April 8, 2025, workshop and solicited written feedback in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," published on April 11, 2025.[42] Most stakeholders were supportive of this concept, with

---

[40] SPD-15 at 8.
[41] SPD-15 at 8.
[42] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Question B.1.a.

some exceptions.[43] PG&E noted that it "would not oppose establishing a reasonable maximum total cap for the Memorandum Account, in general, if there are no restrictions on what costs can and cannot be included."[44] SDG&E stated that it "opposes establishing a maximum total cap for the Memorandum Account at this time."[45]

Ultimately, there was general agreement among stakeholders that it may be valuable to include cost caps on the memorandum account, but setting a specific number for such cap could be premature before total EUP costs and other project details are known after the Phase 2 Application is filed. Accordingly, the Commission finds it is prudent to include a cost cap on the memorandum account but defers establishment of the specific amount of the cap to the Phase 2 Application proceeding. Specifically, in this Resolution we adopt the *CPUC Guidelines* and establish a cost cap for the memorandum account, as follows:

> *The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.*

A cap will better ensure the reasonableness of costs and establish certainty for both ratepayers and shareholders by establishing an upper bound on the total potential costs of an EUP. A cap will also provide ratepayers and the Commission with an increased level of transparency and understanding of overall programmatic impact.

3.3 Audit of the One-Way Balancing Account

Here we explain the general procedure for auditing the one-way balancing account (going forward, referred to as the EUP Audit). The general procedure sets forth the primary and secondary objectives of the audit as well as how the results should be considered by the Commission. A similar procedure was presented by Staff to stakeholders during a Commission workshop on April 8, 2025. Staff adjusted the procedure based on feedback received in response to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" from PG&E, TURN, SDG&E, Cal

---

[43] See Cal Advocates responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 5; and TURN responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 3.

[44] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 8.

[45] SDG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," at 6.

Advocates and MGRA as well as PG&E's response to "Technical Working Group Questions."

In Resolution SPD-15, the Commission noted that due to the importance of the Phase 2 Conditions, it was necessary to include a process to assess whether the costs recorded in the one-way balancing account meet such conditions.[46] The Commission stated:

> [P]eriodic audits of the established balancing account will be performed to ensure that costs booked to the one-way balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, CBR thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund.[47]

SPD-15 also noted that "[t]he details of this audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order."[48] This Resolution adopts the general EUP Audit procedure. Inherent complexities with this program exist, given the volume of data and information expected in the six-month progress reports, and the likelihood of changes to project-related information (CBRs, total costs, and unit costs) between a Phase 2 Application submission date and when the project is deemed used and useful. It is prudent to establish clear primary and secondary objectives for the auditor to review to ensure that costs recovered via the one-way balancing account meet the requirements of the program.

SPD-15 requires forecasted expenditures for the Application as well as for each project in a large electrical corporation's Phase 2 Application.[49] Such information will enable the Commission to evaluate costs that are as close to final as possible and establish Phase 2 Conditions. SPD-15 requires recorded costs of used and useful EUP projects to meet the Phase 2 Conditions in order to be recoverable via the one-way balancing account.[50]

According to SPD-15, it is in Phase 3 that the large electrical corporation must report on its progress implementing the EUP and begin booking costs to the one-way balancing

[46] SPD-15 at 5.
[47] SPD-15 at 5.
[48] SPD-15 at 5-6.
[49] See SPD-15, Appendix A at 7 and 9 for Application requirements #1 and #11.
[50] SPD-15 at 2.

account.[51] After publication of the *Energy Safety Guidelines* on February 20, 2025, and pursuant to the holding in SPD-15 that the details of the audit would be developed later, SPD proposed audit details at the April 8, 2025, workshop. Key stakeholder input is described below.

PG&E recognized that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs. PG&E stated that Screen 2... "is *well before a utility has developed a sound project cost estimate*. In PG&E's case, a sound cost estimate is developed after project estimating."[52] Nevertheless, in accordance with the *Energy Safety Guidelines* and as discussed earlier, the Commission's Phase 2 Decision may issue before a large electrical corporation has developed "sound project cost estimates" for its EUP.[53] As PG&E notes, this data would be incomplete. It is only at Screen 4 when an undergrounding project is fully scoped, and estimating is complete that a reasonably accurate cost forecast can be provided.[54]

TURN urged the Commission not to allow large electrical corporations to book costs into the balancing accounts or flow those costs into rates without a Commission review process that incorporates stakeholder input. In its April 25, 2025, response to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," TURN recommended a process where "no costs would be booked to the balancing account until the Commission has determined in an annual process that recorded costs for that year have met all applicable Phase 2 [C]onditions, as well as the used and useful requirement."[55]

Per SPD-15, the Commission has already found it is reasonable for the Commission to determine upfront what amounts a large electrical corporation may recover in a balancing account and condition recovery on specific requirements.[56] In SPD-15, the Commission implemented the "conditional approval" provision in SB 884 to place specific requirements on what incurred EUP costs are eligible to be booked to the EUP

[51] SPD-15 at 3.
[52] PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 7 (emphasis added).
[53] PU Code Section 8388.5(e)(5) requires the Commission to approve or deny a Phase 2 Application within nine months after it is filed.
[54] In its response to the "Technical Working Group Questions," June 24, 2025, at 6, PG&E indicates that Screen 2 cost estimates can vary from +100% to -50%, whereas at the completion of estimating that range is reduced to +20% to -15%.
[55] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 11.
[56] SPD-15, Finding No. 4 at 19.

one-way balancing account.

One of the criteria SPD-15 established as a requirement for cost recovery via the balancing account is that an undergrounding project must be used and useful.[57] Additionally, the SPD-15 Guidelines established that a Phase 2 Application must identify and exclude any undergrounding costs that have been approved by the Commission for cost recovery in another venue and propose the appropriate venue (the EUP or another cost recovery application) for undergrounding costs still in consideration by the Commission for cost recovery.[58] Thus, it is reasonable to include verification of whether a project is used and useful and determination of whether recorded costs are incremental as a part of the one-way balancing account audit. This Resolution includes a used and useful verification and incrementality determination in the secondary objectives of the audit detailed later in this section.

PG&E acknowledges that the Phase 2 Decision will "influence recovery of millions or billions of dollars of undergrounding work performed over a ten-year period."[59] Additional safeguards are necessary for the audit to ensure that ratepayers only bear costs that the auditor finds meet the Phase 2 Conditions and secondary objectives established by the Commission.

TURN also recommended additional audit objectives should include "verification of project completion, inclusion of (no more than) appropriate cost overheads…use of a reasonable CBR methodology, and an incrementality showing."[60] The Commission agrees with TURN that additional audit objectives would further strengthen program oversight and provide additional ratepayer protections. Except for the recommended audit objective to assess the appropriateness of cost overheads, which the Commission finds to be lacking sufficient detail and explanation, the Commission finds it is reasonable to include many of TURN's recommended audit objectives and has done so in the secondary audit objectives listed below.

This Resolution adopts the general audit procedure for verifying costs recovered via the

[57] *CPUC Guidelines*, Footnote 5 at 4.
[58] *CPUC Guidelines*, Application Requirement No. 2 at 7.
[59] PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 3.
[60] TURN response to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 19.

balancing account are just and reasonable while reducing the time and effort needed to determine if the large electrical corporations should issue ratepayer refunds.[61] The EUP Audit is designed to verify that the large electrical corporation has met the Phase 2 Conditions and the secondary objectives established by the Commission. The following details the procedural objectives of the EUP Audit. As for the specific method the auditor will use to verify whether the costs of underground projects recovered via the one-way balancing account met the primary and secondary objectives, such methodology will be determined via the new Phase 1 Application process, as discussed in Section 3.5.2 below.

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*, as well as any other reporting requirements in SPD-15, the *Energy Safety Guidelines*, and any relevant future Commission decisions. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

A EUP Audit of the one-way balancing account shall occur annually. The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit. Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all Phase 2 Conditions established by the Commission.[62] The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in this Resolution:

---

[61] See the Fifth New Application Requirement discussed in Section 3.1.

[62] Phase 2 Conditions include those established in SPD-15, and those established in relevant future Commission Decisions.

1) Verify that projects are "used and useful;"
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party; and

Future Commission Decisions may also add primary and/or secondary objectives for the Audits specific to that EUP.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in the Phase 2 Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[63] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be filed and served in the Phase 2 Application docket no later than seven days (or such period specified in the Phase 2 Decision) after the due date for opening comments. The Commission may determine the appropriateness of reopening the Phase 2 Application proceeding to consider refunds as described below.

Following its review of the audit report, six-month progress reports, and associated comments, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

The large electrical corporation shall not have input into the direction, focus, or outcome of the audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in a future Commission Decision) of each data request. The large electrical corporation shall also make personnel available

[63] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

for interviews on five days' notice (or such period specified in a future Commission Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

The EUP Audit described above is added to satisfy the audit requirement in SPD-15, while taking into consideration information learned following the adoption of the *Energy Safety Guidelines* and stakeholder input.

3.4 Cost-Benefit Ratio (CBR) Calculation Guidance

As referenced in Resolution SPD-15, the CBR calculation is a cost-benefit analysis methodology that has been developed in the Commission's risk-based decision-making framework (RDF) proceeding (Rulemaking (R.) 20-07-013). At its core, a CBR calculation provides a tool to aid the Commission in deciding between competing options for utility spending in an objective manner by quantifying both mitigation costs and the benefits of avoided harm in a way that allows them to be directly compared.

Because the RDF proceeding is applicable to assessing utility spending across its entire portfolio of all enterprise risks, any directives regarding CBR calculations must inherently be broadly applicable. However, in the context of EUPs, which discretely focus on the specific risks of wildfire and reliability impacts from outage programs, more specific, targeted direction for CBR calculations is necessary.

In the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," issued on April 11, 2025, Staff solicited stakeholder input on whether the Commission should provide additional guidance for CBR calculations made in the context of SB 884.[64] The questions explored a variety of topics related to CBR calculations, including the appropriate granularity for monetizing electric reliability, discount rate scenarios, risk scaling, and the treatment of combined benefits (impacts on both wildfire and reliability) of mitigations. One stakeholder, PG&E, explicitly objected to the Commission providing additional guidance on calculating CBRs for EUPs as it believes doing so "is unnecessary and will add additional delay to issuing any updated cost recovery guidelines."[65] As noted above, PG&E also explained that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs as "[i]t is not unusual for estimated costs and CBRs to vary between the initial estimate and the

[64] "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," Questions E.1-E.5.

[65] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 16.

updated estimate as we learn more about project scope, schedule and cost through the project scoping process."[66] According to PG&E, "[b]etween Screens 2 and 4, we will revise our cost estimates (which impact CBRs) to account for better information we learn during the scoping phase such as more precise route selection and addressing tree-strike, ingress/egress, and/or feasibility issues."[67] Given the range of responses received to questions on the specific, technical aspects impacting CBR calculations for an EUP and that uncertainty in the CBR calculations may impact additional conditions for cost recovery that we may require, the Commission establishes a new Phase 1 Application process to determine how CBR calculations must be made for the purpose of the SB 884 program. Additional details on the new application process are provided in Section 3.5 below.

3.5 New Phase 1 Application

This resolution enumerates certain aspects of the SB 884 program that had been deferred in SPD-15. It is evident from comments that the program would benefit from further exploration of three additional issues:

1. CBR Calculation
2. Audit Methodology
3. Cost Recovery Conditions

Although these three issues could be deferred to the Phase 2 Application, the statutory time limit for considering the Phase 2 Application is expedited, at nine months. To reduce the risk of delaying a decision on the Phase 2 Application, the three large electrical corporations eligible for participation in the SB 884 program are directed to file a joint application within 60 days of the issuance of this resolution requesting approval of a proposal for addressing each of these three issues. As we are requiring this application to be filed prior to the Phase 2 Application, we refer to it as the "Phase 1 Application."[68]

Specific guidance for the content of each proposal to be included in the Phase 1 Application follows.

3.5.1 CBR Calculation

The large electrical corporations' proposal for the CBR calculation shall detail at least

[66] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 9.

[67] PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 9.

[68] While SPD-15 acknowledges Energy Safety's consideration of the EUP also in Phase 1, here we refer to a new application process that is intended to address three discrete issues relevant to the *CPUC Guidelines* and does not duplicate or replace Energy Safety's consideration of the EUP.

one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The large electrical corporations' proposal shall be designed to promote comparability, transparency, and traceability in CBR calculations across large electrical corporations, while remaining adaptable to future improvements in data availability and analytical approaches. Any proposed methodology shall apply to the project level and may allow for scalability to the portfolio level. It shall complement the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the CBR for the purposes of EUPs and provide more information on the calculation's key components. These key components of at least one proposed methodology shall, at a minimum, include:

- **Total Capital Cost**, defined as capital expenditures tied to project implementation. The relationship between Total Capital Costs and other categories, such as Operating and Maintenance (O&M) Costs, O&M Savings, or Net Salvage values,[69] should be addressed.
- **Risk Scaling,** which should address whether unscaled (i.e., risk-neutral) risk values should be used in the CBR calculations.
- **Total Mitigation Benefit,** which may include:
    a. Risk Reduction, including Wildfire Ignition Risk and Outage Program Risk.
    b. Other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

  Different types of mitigation benefits should be clearly identified and distinguished to facilitate transparency and avoid double-counting.
- O&M Costs associated with operating and maintaining the project.
- O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline.[70]

[69] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.
[70] No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU)implementation . The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives.

- **CBR Year Zero**, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits.
- **Interruption Cost Estimate (ICE)**[71] **Calculator Granularity**, the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability should be addressed.
- **Backcasting**, a method for recalculating CBRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison should be proposed.

All stakeholders unanimously agreed on the definition of CBR Year Zero as presented above and that definition shall be included in the large electrical corporations' proposal.[72]

After the adoption of Resolution SPD-15, the *Energy Safety Guidelines* introduced the concept of the "subproject."[73] During the scoping phase (after Screen 2), the *Energy Safety Guidelines* allow the large electrical corporation to divide an "Eligible Circuit Segment" into one or more subprojects for operational reasons or to reflect that a portion of the circuit segment will be treated with a wildfire mitigation other than undergrounding.[74] The Commission's *SB 884 Project List Data Requirements Guidelines* refer to the subproject designation as an RRU in order to align with approaches established in the RDF Proceeding.[75]

The *Energy Safety Guidelines* allow the large electrical corporation to establish subprojects after Screen 2, which could happen after the Commission's Phase 2 Decision is adopted. This change created a need to incorporate the concept of "backcasting" into

---

[71] https://icecalculator.com/, see also D.22-12-027 OP 2b.
[72] See, for instance, PG&E responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 19 and TURN responses to "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," April 25, 2025, at 29.
[73] Energy Safety defines subproject as "a delimited portion of work on a Confirmed Project." *Energy Safety Guidelines* at A-6.
[74] *Energy Safety Guidelines* at 14.
[75] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M545/K343/545343783.PDF

the CBR methodology proposal.[76] When a large electrical corporation elects to use the subproject designation, the concept of a backcast is essential in the SB 884 context to enable a consistent comparison between the forecasted RRU values reported in the progress reports and the backcasted RRU values that would have been calculated had the RRU structure been applied in the Phase 2 Application using the data submitted at that time.

In its June 24, 2025, responses to "Technical Working Group Questions," PG&E stated, "[i]f required, PG&E could calculate a subproject level CBR for the undergrounding portions of the subproject.…"[77] Although it is able to produce such a calculation, PG&E argued that the backcasting requirement should be omitted "because PG&E uses project-level (circuit segment level) CBRs and costs to make mitigation decisions...."[78] However, PG&E's data request responses clearly demonstrate that it uses a decision-tree for determining the scope of undergrounding subprojects for hybrid projects (projects that use multiple mitigation methods) which PG&E stated will be used to inform an EUP.[79]

After reviewing all these considerations, the Commission finds that the requirement for backcasting is reasonable and allows for greater alignment with the *Energy Safety Guidelines*. The electrical corporations shall include guidance on backcasting in any CBR methodology proposal.

3.5.2 Audit Methodology

SPD-15 recognized that the Commission will assess whether costs recorded in the one-way balancing account meet the Phase 2 Conditions: "This audit mechanism [to evaluate whether Phase 2 Conditions are satisfied], coupled with the fact that any costs not meeting the established conditions are subject to refund if the Commission so orders, adds a critical ratepayer protection to ensure the large electrical corporations are complying with the determinations made in any Phase 2 Decision."[80] To carry out this intent SPD-15 adopted an audit process requirement, but left details to a later

---

[76] Although used in slightly different ways, the concept of a backcast further aligns with what the *Energy Safety Guidelines* refer to as a "backtest," used to validate new wildfire risk models. See *Energy Safety Guidelines* at 52.
[77] PG&E responses to "Technical Working Group Questions," June 24, 2025, at 16.
[78] PG&E responses to "Technical Working Group Questions," June 24, 2025, at 15.
[79] PG&E response to Data Request SPD-PGE-SB884-018, May 16, 2025, Question 3a, available at https://www.pge.com/assets/pge/docs/outages-and-safety/safety/eup-spd-data-request-018.zip.
[80] SPD-15 at 12.

Resolution.[81] This Resolution adopts an audit procedure, audit objectives, and requires the large electrical corporations to submit a proposed audit methodology for Commission consideration that will support the auditor's ability to verify whether the costs of a project satisfy the Phase 2 Conditions and secondary objectives adopted by the Commission.

The large electrical corporations shall jointly propose, in the Phase 1 Application, a methodology for verifying whether they satisfy the Phase 2 Conditions and the secondary objectives of the audit.[82] The appropriate methodology can then be addressed during the Phase 1 Application proceeding and detailed in the Phase 1 Decision. This upfront determination of the appropriate methodology to ensure the satisfaction of Phase 2 Conditions and the secondary objectives of the audit provides dual benefits. First, having this knowledge upfront allows large electrical corporations to understand the expectations of the one-way balancing account audit and reduce the need for future refunds. Second, establishing the methodology will enable the auditor to efficiently review project costs and allow the Commission to determine whether the costs were appropriately recorded.

The Phase 1 Application shall include a detailed description of the proposed methodology that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:

a. Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);
b. Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);
c. Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);
d. Determining that the average recorded CBR for all projects completed in any given two-year period equals or exceeds the approved threshold CBR value. (Condition #4); and

For the secondary objectives, this method must include an approach for:

e. Verifying that a project is used and useful.
f. Verifying the incrementality showing found in Application Requirement

[81] SPD-15 at 15.
[82] The EUP Audit is detailed later in this Resolution.

No. 2.

3.5.3 Cost Recovery Conditions

The Phase 1 Application shall include a proposal for any additional portfolio or project-level conditions necessary to ensure that costs booked to balancing accounts are just and reasonable. At a minimum, large electrical corporations shall consider the following types of quantitative conditions: conditions that address how an undergrounding project compares to alternative mitigations; conditions that address how the actual CBR of a project compares to its forecasted CBR; conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost. For each quantitative condition, large electrical corporations should propose a numerical threshold that can be used to evaluate whether the condition has been met. Parties to the Phase 1 Application may respond to each of the large electrical corporations' proposals and make counter proposals within 15 calendar days of the large electrical corporations' filing(s).

3.5.4 Required Data

In order to consider the practical implications of the proposed CBR methodologies, audit methodologies, and cost recovery conditions, upon filing their EUP with Energy Safety, large electrical corporations shall file in the Phase 1 Application proceeding the most recent versions of all available data identified in the *SB 884 Project List Data Requirements Guidelines* using the *SB 884 Project List Data Template*. In order to facilitate full and transparent review of these issues, staff are directed to modify the data requirements to include the annual total capital costs and total operating and maintenance costs for each proposed undergrounding project over its useful life; for each alternative project for its useful life; and for an assumed no-build scenario in which no project is built over the useful life of the existing equipment.

COMMENTS

PU Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review. However, given that this Resolution is issued outside of a formal proceeding, interested stakeholders need not have party status in a Commission proceeding to submit comments.

Section 311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding. The

30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this Draft Resolution was mailed to the SB 884 Notification List and service lists of A.25-05-009, A.23-05-010, A.22-05-016, and R.18-10-007 and placed on the Commission's agenda no earlier than 30 days from its mailing date.

Opening comments were filed by were filed by The Utility Reform Network (TURN); California Public Advocates (Cal Advocates); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); and Mussey Grade Road Alliance (MGRA) on September 4, 2025, and in accordance with any instructions accompanying the notice. Reply comments were filed by TURN, Cal Advocates, PG&E, and MGRA on September 9, 2025. We make the following changes in response to comments but otherwise do not change the Draft Resolution.

Audit Report Comment Period: TURN stated that to allow parties sufficient time to review and provide meaningful comments on the audit report, the opening comment period on the audit report should be changed from 20 days after the audit report is filed and served by the large electrical corporation to 42 days.[83] Similarly, TURN recommends that Reply comments on the audit report should be filed no later than seven days after the due date for opening comments instead of five days.[84] TURN's recommended opening and reply comment periods on the audit reports align with the interval for comments on the six-month progress reports. In response to these comments, the Commission has modified the Resolution and *CPUC Guidelines* to reflect TURN's recommended comment period on the audit report.

Audit and Refund Process: TURN objected to the draft language of SPD-37 providing that a ratepayer representative may file a petition for modification (PFM) seeking reopening of the Phase 2 Application proceeding if it believes a refund is appropriate. TURN suggested that refunds instead be implemented by Commission action. We remove the sentence that states parties may file a PFM, to request a refund to ratepayers, since the PFM option is always available to an intervenor under Commission rules. SPD-37 and the *CPUC Guidelines* now provide that the Commission will determine the appropriateness of reopening the Phase 2 Application if a refund is at issue.

CBR name change to BCR: Cal Advocates notes that D.25-08-032 in the Commission's

[83] TURN Opening Comments on Draft Resolution SPD-37 at 7.
[84] TURN Opening Comments on Draft Resolution SPD-37 at 7.

Risk-Based Decision-Making Framework rulemaking changes the term "Cost-Benefit Ration (CBR)" to "Benefit-Cost Ratio (BCR)."[85] This Resolution notes this name change in a footnote and has made the name change in the *CPUC Guidelines.*

Five-day period to respond to data requests: TURN recommends that party responses to data requests be due three business days from the date of the request due to the short turnaround times in the program.[86] This Resolution already requires a five-day response time, but we have conformed all supporting materials to match this five-day requirement. The *CPUC Guidelines* now require that responses to data requests related to the CPUC's SB-884 Program, including the six-month progress reports and audit reports, be served no later than five days after delivery of the data request.

CBR Calculation Guidance and New Phase 2 Conditions: PG&E recommends pausing the adoption of the *CBR calculation* guidelines and to instead implement a process for establishing a method to calculate CBRs, and noted that cost estimates can vary significantly (from +100% to -50%) at Screens 2 and 3 but cost estimates will be significantly more accurate (vary from +20% to -15%) at Screen 4.[87] PG&E and SDG&E argue it is inappropriate to require the CBR of an undergrounding project to exceed the CBR of all alternative mitigations by a threshold determined in the Phase 2 Decision.[88] PG&E recommends that the forecasted CBR of the undergrounding project should be within 50% of the forecasted CBR of the highest alternative mitigation considered for that project. TURN opposes pausing the adoption of CBR calculation guidelines and adopting an alternative process, stating that a "re-do is not warranted just because PG&E does not like the results."[89] We acknowledge that there may be uncertainty in the cost forecasts presented in the Screen 2 data that could be relevant to both the undergrounding project and the alternative mitigation and would influence the comparison between the CBR values. Because of the degree of uncertainty in the cost forecasts and other technical aspects of CBR that impact additional cost recovery conditions, the determination of the CBR calculation and any additional conditions on balancing account cost recovery are deferred to a future Commission Decision.

---

[85] Cal Advocates Opening Comments on Draft Resolution SPD-37 at 8. See also D.25-08-032, CoL 39.
[86] TURN Opening Comments on Draft Resolution SPD-37 at 9.
[87] PG&E Opening Comments on Draft Resolution SPD-37 at 9-13.
[88] SDG&E Opening Comments on Draft Resolution SPD-37 at 5; PG&E Opening Comments on Draft Resolution SPD-37 at 11.
[89] TURN Reply Comments on Draft Resolution SPD-37 at 2.

<u>FINDINGS</u>

1. On October 14, 2024, the Commission's Safety Policy Division (SPD) staff issued a list of "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" for stakeholder comment.
2. On November 12, 2024, responses to "Questions for Stakeholders Regarding the CPUC SB-884 Guidelines" was received from stakeholders.
3. On February 20, 2025, Energy Safety issued its own SB 884 *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*).
4. On April 8, 2025, SPD held a workshop to discuss potential modifications to the SPD-15 Guidelines following publication of the *Energy Safety Guidelines*.
5. On April 25, 2025, responses to the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines" were received from stakeholders.
6. On June 3, 2025, and June 10, 2025, SPD held technical working group (TWG) meetings on potential updates to the *SB 884 Project List Data Requirements Guidelines*.
7. On June 24, 2025, SPD held a TWG meeting to discuss the Interruption Cost Estimator Calculator (ICE 2.0) element of the SB 884 program.
8. The *Energy Safety Guidelines* do not require all projects submitted in an Electrical Undergrounding Plan (EUP) to pass through Screens 3 and 4 before being approved by Energy Safety.
9. The vast majority of undergrounding projects approved by Energy Safety through its Project Acceptance Framework may only be preliminarily scoped.
10. It is not until a project successfully passes Screen 3 and Screen 4 of the *Energy Safety Guidelines* that a project will be completely scoped.
11. A large electrical corporation will not be required to obtain Energy Safety approval of undergrounding projects it intends to construct after Energy Safety approves its EUP.
12. A large electrical corporation will provide new details about undergrounding projects in its six-month progress reports.
13. Because significant changes can be made to the economic metrics of an undergrounding project as it is more accurately scoped in Screens 3 and 4, the large majority of forecasted data available to the Commission at the time the Phase 2 Application is considered, and upon which its EUP cost approval conditions will be based, will not be sufficiently precise to provide the necessary cost containment controls.

14. In consideration of the *Energy Safety Guidelines*, the questions and responses from stakeholders, and feedback from the SPD workshop and TWG meetings, described above, it is reasonable to update and refine the guidelines adopted in Resolution SPD-15 issued March 8, 2024.
15. Updates and additions to the Phase 2 Application requirements are necessary to align programmatic information required by the *Energy Safety Guidelines* and *CPUC Guidelines* and to ensure the Commission has adequate undergrounding project cost information to determine whether cost recovery is reasonable.
16. Allowing undergrounding projects that have forecasted Cost-Benefit Ratios (CBR) below 1.0 to be included in a Phase 2 Application would be unreasonable, especially considering that undergrounding is the most capital-intensive grid hardening investment available.
17. Because of the degree of uncertainty in cost forecasts at Screens 2 and 3 and other technical aspects of the CBR calculation that impact the reasonableness of cost recovery, additional Phase 2 Conditions will be considered in a separate Phase 1 Application proceeding.
18. Staff proposed a maximum total cost cap for the memorandum account at the April 8, 2025, workshop and solicited written feedback in the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," published on April 11, 2025.
19. Stakeholders generally agreed at the April 8, 2025, workshop that it may be valuable to include cost caps on the memorandum account, but setting a specific number for such cap could be premature before total EUP costs and other project details are known after the Phase 2 Application is filed.
20. It is prudent to establish an upper bound on the total potential costs of an EUP by capping the total costs recovered from the memorandum account at a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account.
21. The percentage value of the memorandum account cost cap should be established in the Phase 2 Decision.
22. An EUP Audit of the one-way balancing account should occur annually.
23. The primary objective of the EUP Audit is to determine if the costs recorded into the one-way balancing account met the Phase 2 Conditions.
24. The secondary objectives of the EUP Audit include verifying that an undergrounding project is used and useful, verifying the incrementality showing found in Application Requirement No. 2, and validating the methodology used to calculate a CBR for a given project.
25. Additional primary and/or secondary objectives for an EUP Audit may be included in the Phase 1 or Phase 2 Decision.

26. The EUP Audit should begin no later than 60 days (or such period specified in the Phase 1 or Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given calendar year.
27. The large electrical corporation should not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process.
28. The large electrical corporation should provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in the Phase 2 Decision) of each data request.
29. The large electrical corporation should make personnel available for interviews on five days' notice (or such period specified in the Phase 2 Decision) if the auditor seeks substantive information, and a custodian of records for questions about the location and content of requested information.
30. In the "Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines," issued on April 11, 2025, Staff solicited stakeholder input on whether the Commission should provide additional guidance for CBR calculations made in the context of SB 884.
31. Guidance on how to calculate CBRs is necessary to ensure projects achieve wildfire risk reduction without undue expense and provide a means for equitable comparison against potential alternative mitigations.
32. The requirement for backcasting is reasonable and allows for greater alignment with the *Energy Safety Guidelines*.
33. It is reasonable to require the large electrical corporations to file a Phase 1 Application with proposals for addressing the CBR calculation, audit methodology, and additional cost recovery conditions.
34. The *SB 884 Project Lists Data Requirements-Preliminary* were refined, revised, and finalized following a series of TWG meetings, as authorized by SPD-15, and are included for information only with this Resolution as the *SB 884 Project List Data Requirements Guidelines* in Appendix 2 of the *CPUC Guidelines*.
35. The *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* were issued by SPD on July 24, 2025.
36. Future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* may be necessary.
37. It is reasonable to authorize SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one TWG meeting to present and discuss the changes.

THEREFORE, IT IS ORDERED THAT:

1. Resolution SPD-37 is approved and adopted.
2. The large electrical corporations shall demonstrate that the Phase 2 Conditions, including any new Phase 2 Conditions included in future Commission Decisions, have been met in their six-month progress reports.
3. Costs recovered in the memorandum account shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account and according to the requirements established in the large electrical corporation's Phase 2 Decision.
4. An Electrical Undergrounding Plan Audit shall be conducted annually for undergrounding project costs recovered by the large electrical corporation through the one-way balancing account.
5. The primary objective of an Electrical Undergrounding Plan Audit is to verify whether the costs of the large electrical corporation's undergrounding projects recovered through the one-way balancing account meet the Phase 2 Conditions.
6. The secondary objectives of an Electrical Undergrounding Plan Audit are to verify that an undergrounding project is used and useful and verify the incrementality showing found in Application Requirement No. 2.
7. The *Senate Bill 884 Program: California Public Utilities Commission Guidelines* applicable to all large electrical corporations shall be updated to conform with the requirements of this resolution. They supersede the guidelines adopted in Resolution SPD-15.
8. Large electrical corporations shall comply with the *Senate Bill 884 Program: California Public Utilities Commission Guidelines*. The large electrical corporations must complete the *SB 884 Project List Data Template*[90] according to the requirements found in the *SB 884 Project List Data Requirements Guidelines* and submit the completed *SB 884 Project List Data Template* with their Phase 2 Application and six-month progress reports.
9. Large electrical corporations shall file their completed *SB 884 Project List Data Template* to the Phase 1 Application docket upon submission of their Electrical Undergrounding Plan to Energy Safety.
10. Parties may review, file and serve opening comments on the six-month progress reports and audit reports in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after such reports are filed and

[90] The *SB 884 Project List Data Template* is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-template-clean-version_2.xlsx

served. Reply comments on the six-month progress reports and audit reports may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

11. We authorize Safety Policy Division to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* after hosting at least one technical working group meeting to present and discuss the changes.
12. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to file a Phase 1 Application within 60 days of the effective date of this Resolution requesting Commission approval of proposals for a CBR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as specified in this Resolution.

This Resolution is effective today.

The foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 4, 2025; the following Commissioners voting favorably thereon:

ALICE REYNOLDS
President

DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
MATTHEW BAKER

Commissioners

Dated December 4, 2025, at San Francisco, California

ATTACHMENT A

SB 884 Program: CPUC Guidelines (Rev 3 Clean Version)

California Public Utilities Commission

SB 884 Program: CPUC Guidelines

SAFETY POLICY DIVISION

December 10, 2025

Table of Contents

Purpose:

These *Guidelines,* and the adopting Commission Resolution, satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution infrastructure undergrounding program consistent with Senate Bill (SB) 884.[1] These *Guidelines* address the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (as defined below) and related costs.

[1] McGuire; Stats. 2022, Ch. 819

Background:

SB 884, effective January 1, 2023, authorizes electrical corporations with 250,000 or more customer accounts within the state (i.e., large electrical corporations) to participate in an expedited utility distribution infrastructure undergrounding program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan" or "EUP"), including, among other requirements, the undergrounding projects to be constructed as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. Energy Safety may require the large electrical corporation to modify the Plan before approving it. Energy Safety may only approve the Plan upon finding it will achieve, at least, both of the following:[2]

1) Substantially increase reliability by reducing use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and other outage programs.
2) Substantially reduce wildfire risk.

The large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the Plan's costs (hereafter, "Application"). However, prior to formally filing the Application with the Commission, the large electrical corporation shall provide a copy of the Application it intends to file to the Commission's Safety Policy Division (SPD) for a completeness review to identify any obvious omissions or errors in the intended Application. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected before the Application is officially submitted and filed with the Commission.

On or before nine months after the Application's official filing date, the Commission shall review and conditionally approve or deny the Application. The Commission may, however, require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application prior to conditional approval. As further explained below, if the Commission or staff determines that minor corrections or clarifications are needed for the filed Application, the large electrical corporation may be required to modify the Application and provide corrections or clarifications within five (5) business days after being noticed. If the Commission or staff determines the filed Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, the Commission or staff may then require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for Commission review.

If the Plan is approved by Energy Safety and the Application requesting review and conditional approval of the Plan's costs is approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to

[2] Energy Safety has issued guidelines detailing the requirements for submission and review of undergrounding Plans. See https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true

review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 of each year over the course of the Plan.[3] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has corrected the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

Figure 1 below shows an overview of the timelines, events, and responsible parties for implementation of the SB 884 program.

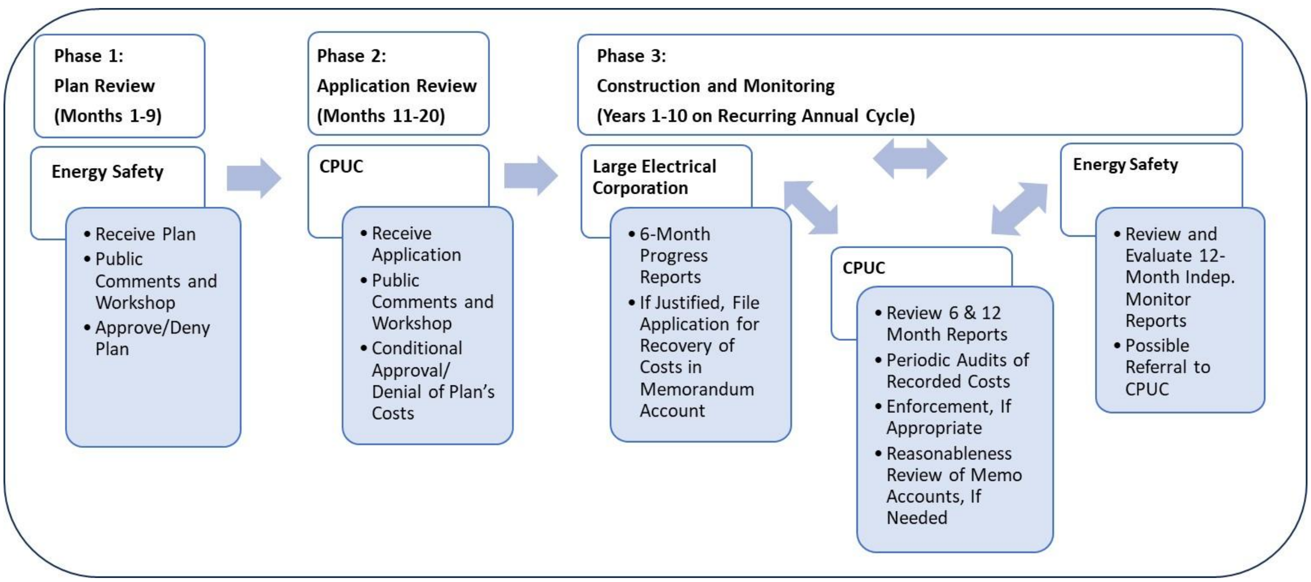

Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline

[3] Pursuant to Public Utilities Code, Section 8388.5(h), Energy Safety is required to publish these reports on its website.

SB 884 Program Process and Requirements:

The SB 884 Program will be executed in up to three phases:

- Phase 1 in two parts:
  - Energy Safety Plan review and approval/denial.
  - Joint Phase 1 Application from large electrical corporations to resolve issues identified in Resolution SPD-37, filed with Commission.
- Phase 2: Application submitted to Commission for review and conditional approval.
- Phase 3: Construction and periodic audits of costs recorded in the one-way balancing account, as well as just and reasonableness reviews of recorded costs in the memorandum account described below.

If Energy Safety approves the large electrical corporation's Plan in Phase 1, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial) via a Phase 2 Decision. The Commission will review the costs submitted in any Application. Only if costs[4] meet certain conditions (Phase 2 Conditions), will the Commission authorize their recovery via a one-way balancing account, which shall remain subject to audit. If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs may be subject to refund. The Phase 2 Conditions for recovering costs via the one-way balancing account will include those listed in the "Conditions for Approval of Plan Costs" section herein, as well as any other conditions the Commission deems appropriate in the relevant Application's proceeding. If the Commission approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to record, in a memorandum account, any Plan costs that fail to meet the Phase 2 Conditions.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's issuance of the Phase 2 Decision. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program. The large electrical corporation shall also report on its progress and begin booking costs to the one-way balancing account established in Phase 2, subject to periodic audits and refunds if the Commission so orders. In Phase 3, given the inherent uncertainties with planning across a 10-year period and certain costs being unforeseeable during Phase 2, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for implementation costs that do not meet the Phase 2 Conditions, and were recorded in the designated memorandum account up to a cap determined in the Phase 2 Decision. During Phase 3, the Commission will review any Phase 3 Applications for recovery of costs recorded in the memorandum account to determine whether such costs were just and reasonable, and incremental to any other costs approved by the Commission. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be found to be just and reasonable before being authorized for recovery. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever is last.

---

[4] Costs can only be recovered once the undergrounding project is considered used and useful.

Given the importance of the Phase 2 Conditions and the requirement that any costs recorded in the one-way balancing account must meet the Phase 2 Conditions, these *Guidelines* include a process to assess whether the recorded costs meet such conditions. Accordingly, periodic audits of the established balancing account will be performed to ensure the costs booked to the balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, benefit cost ratio (BCR) thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

Due to the SB 884 Program's expedited schedule, unless otherwise directed by the Commission, large electrical corporations shall respond to discovery requests within five (5) days in either Phase of the SB 884 Program.

Phase 1 – Joint Application to resolve SPD-37 Issues

The three large electrical corporations eligible for participation in the SB 884 program (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric) are directed to file a joint application, hereafter the Phase 1 Application, within 60 days of the issuance of Resolution SPD-37 requesting approval of a proposal for addressing each of these three issues:

1. BCR Calculation
2. Audit Methodology
3. Cost Recovery Conditions

Specific guidance for the content of each proposal to be included in the Phase 1 Application follows.

BCR Calculation

The large electrical corporations' proposal for the BCR calculation shall detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The large electrical corporations' proposal shall be designed to promote comparability, transparency, and traceability in BCR calculations across large electrical corporations, while remaining adaptable to future improvements in data availability and analytical approaches. Any proposed methodology shall apply to the project level, and may allow for scalability to the portfolio level. It shall complement the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the BCR for the purposes of EUPs and provide more information on the calculation's key components. These key components of at least one proposed methodology shall, at a minimum, include:

- **Total Capital Cost**, defined as capital expenditures tied to project implementation. The relationship between Total Capital Costs and other categories, such as Operating and Maintenance (O&M) Costs, O&M Savings, or Net Salvage values,[5] should be addressed.

[5] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.

- **Risk Scaling,** which should address whether unscaled (i.e., risk-neutral) risk values should be used in the BCR calculations.
- **Total Mitigation Benefit,** which may include:

  a. Risk Reduction, including Wildfire Ignition Risk and Outage Program Risk.

  b. Other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

Different types of mitigation benefits should be clearly identified and distinguished to facilitate transparency and avoid double-counting.

- O&M Costs associated with operating and maintaining the project.
- O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline.[6]
- **BCR Year Zero**, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits. This BCR Year Zero definition shall be included in the large electrical corporations' BCR methodology proposal.
- **Interruption Cost Estimate (ICE)[7] Calculator Granularity**, the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability should be addressed.

Backcasting, a method for recalculating BCRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison should be proposed. The large electrical corporations shall include guidance on backcasting in any BCR methodology proposal.

Audit Methodology

The Phase 1 Application shall include a detailed description of the proposed methodology that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:

a. Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);

b. Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);

---

[6] No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU)implementation. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives.

[7] https://icecalculator.com/, see also D.22-12-027 OP 2b.

c. Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);

d. Determining that the average recorded BCR for all projects completed in any given two-year period equals or exceeds the approved threshold BCR value. (Condition #4); and

For the secondary objectives, this method must include an approach for:

e. Verifying that a project is used and useful.

f. Verifying the incrementality showing found in Application Requirement No. 2.

Cost Recovery Conditions

The Phase 1 Application shall include a proposal for any additional portfolio or project-level conditions necessary to ensure that costs booked to balancing accounts are just and reasonable. At a minimum, large electrical corporations shall consider the following types of quantitative conditions: conditions that address how an undergrounding project compares to alternative mitigations; conditions that address how the actual BCR of a project compares to its forecasted BCR; conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost. For each quantitative condition, large electrical corporations should propose a numerical threshold that can be used to evaluate whether the condition has been met. Parties to the Phase 1 Application may respond to each of the large electrical corporations' proposals and make counter proposals within 15 calendar days of the large electrical corporations' filing(s).

Required Data

In order to consider the practical implications of the proposed BCR methodologies, audit methodologies, and cost recovery conditions, upon filing their EUP with Energy Safety, large electrical corporations shall file in the Phase 1 Application proceeding the most recent versions of all available data identified in the *SB 884 Project List Data Requirements Guidelines* using the *SB 884 Project List Data Template*

Phase 1 Application Submission Requirements:

The Phase 1 Application submitted to the Commission shall meet all the following requirements.

Submission Deadline:

The Phase 1 Application shall be jointly filed by the three large electrical corporations eligible for participation in the SB 884 Program within 60 days of the issuance of Resolution SPD-37.

Phase 1 Application Type:

The Phase 1 Application shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[8] Each section of the Phase 1 Application shall indicate the person(s) who sponsors the section and would serve as a witness if evidentiary hearings are required.

---

[8] Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 3, Rule 3.2.

Phase 1 Application Submission:

The Phase 1 Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service lists for each large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[9] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporations, that will cause the Phase 1 Application to broadly reach interested parties.

Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application.[10] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days of notice. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for the Commission's review.

Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[11] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is

[9] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

[10] Public Utilities Code, Section 8388.5(e)(5).

[11] Pre-submission of the Application for completeness review shall be submitted to SB884@cpuc.ca.gov.

not a substantive review or disposition of the Application and does not limit the Commission's or staff's ability to require the large electrical corporation to otherwise modify or resubmit the Application.

Phase 2 – Application Submission and Review:

These *Guidelines* recognize that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

Application Submission Requirements:

Applications submitted to the Commission seeking conditional approval of Plan costs shall meet all the following requirements.

Submission Deadline:

Applications for Commission review, and conditional approval or denial of the Plan's costs, as such conditional approval is described herein, must be submitted to the Commission within 60 days following Energy Safety's approval of the Plan.

Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[12] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent GRC, the SB 884 notification list linked here,[13] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties. A copy of the Application should also be sent to each communications company that has equipment on poles where undergrounding is planned.

Application Requirements:

For the purposes of these *Guidelines*, all program and project costs reported in the Application shall include the standard project costs including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and

---

[12] Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 3, Rule 3.2.

[13] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

permitting. In addition, all ratepayer impacts shall be shown by all ratepayer classifications (e.g., residential, agricultural, commercial, etc.) to the extent such information is available.

All cost and BCR data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following are required contents of all Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[14]) and cost forecasts[15] in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:
    a) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>approved</u> in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.
    b) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts <u>still under consideration</u> in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.
3) The Application shall include the large electrical corporation's best estimate, including all underlying assumptions, of the proposed annual revenue requirements and proposed ratepayer impacts for each year that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.
4) The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division

[14] As used in this context, "conversion rate" means the ratio of underground mileage required to replace the equivalent overhead lines. Given prior evaluation of undergrounding requests in other Commission proceedings, it is known that a mile of undergrounding corresponds to replacement of less than one mile of overhead assets.

[15] For clarity, the term cost forecasts is used in place of the term cost targets that are discussed in PUC 8838.5 (3)(1).

oversight and a non-disclosure agreement in place,[16] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[17]

5) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management), collectively "savings," and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[18]
    a) The Application shall distinguish between forecast costs already approved by the Commission for recovery and forecast costs that have not yet been the subject of a request for recovery.
    b) For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
    c) The application shall explain the proposed disposition of all identified savings and explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers.
6) The Application shall include cost forecasts for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.
    a) Cost forecasts shall be provided for each projected year in the 10-year Plan.
    b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.
    c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.
7) The Application shall include an explanation of how the cost forecasts are expected to decline over time due to cost efficiencies and economies of scale.
8) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or

[16] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[17] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

[18] For examples of cost savings that may be appropriate to include, refer to the Lawrence Berkeley National Laboratory white paper. Peter H. Larsen, "A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines" in Energy Economics Vol. 60, 2016 pp. 47-61. Please note that this methodology is referenced for illustrative purposes only. Different methodologies and/or cost categories may be appropriate to include.

economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

9) The Application shall present the forecasted average BCR across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. BCR must be calculated as directed in the Phase 1 Decision. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[19] The costs and benefits of any projects that will include secondary lines and service drops must also be included.
10) The Application shall include the forecasted BCRs across all projects, by year and for the total Application period, for each alternative wildfire mitigation hardening method considered, in place of undergrounding, including forecasted BCRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.
    a) The large electrical corporation shall use reasonable and comparable assumptions in its calculations of forecasted BCRs for both undergrounding and each alternative wildfire mitigation method considered, including combinations thereof.
11) The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.
    a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.
    b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.
12) For each project included in the Application, the large electrical corporation shall provide, at a minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and searchable pdf file[20] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission.
13) The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*.
14) The Application shall only include undergrounding projects that have a forecasted BCR greater than or equal to 1.

[19] Based on information provided in PG&E's wildfire mitigation plans and current general rate case, the overhead to underground conversion rate is approximately 1.25. This means that it would require PG&E approximately 125 miles of underground circuit miles to convert 100 miles of overhead infrastructure to underground. As such, calculated benefits would relate to the 100 miles of overhead infrastructure undergrounded and not the 125 miles of undergrounding required to do so. The underground conversion rate will vary per large electrical corporation.

[20] See Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 1, Rule 1.3(b) for complete submission requirements of pdf files.

15) The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application.
    a) The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[21]
16) The Application shall include:
    a) The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
    b) The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety.
17) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format.
    a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
    b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
    c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.
18) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request, including funding already received;
    e) Next steps, including timelines for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).
19) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.
20) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[22]
21) The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.
22) The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:
    a) The ownership and use of existing utility poles where undergrounding projects are planned;

---

[21] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

[22] Resolution E-5254 adopted procedural mechanisms for review and approval of electric and gas investor-owned utility cost recovery requests related to various federal funding and grant programs. Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

b) How the large electrical corporation will address the affected shared poles, including who will own and maintain the poles if the responsible communication provider opts not to concurrently underground their infrastructure;
c) The full array of currently offered or discussed proposals for how to add conduit for such communication companies in the large electrical corporation's trenches, including, wherever possible, the proposed unit costs associated with such offerings or proposals.

23) The Application shall include a plan of how and when the large electrical corporation will remove poles from its rate base whose ownership is transferred to a communications company.
24) The Application shall include workforce development cost forecasts for each year of the Plan.
25) The Application shall include a copy of the Plan approved by Energy Safety.

Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered.

Conditions for Approval of Plan Costs:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" To protect ratepayers from unexpected and inefficient cost overruns, the Commission establishes the following conditions for any costs booked to the one-way balancing account established in Phase 2:

1) Total annual costs must not exceed a cap based on the approved cost cap for that specific year.[23]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4) The average recorded BCR[24] for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold BCR value[25] for the current year.

Any further reasonable conditions adopted by a future Commission decision.

Memorandum Account Cap:

The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing

---

[23] Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of these *Guidelines*.

[24] The "recorded BCR" is the BCR calculated using recorded cost values, as opposed to cost forecasts.

[25] The "threshold BCR value" will establish the minimum BCR that must be achieved for cost recovery.

account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.

Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery:

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, the large electrical corporation shall also report on its progress, and begin booking costs to the one-way balancing account established in Phase 2, which shall remain subject to periodic audits, and refund if the Commission so orders. In Phase 3, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for any implementation costs that do not meet the Phase 2 Conditions and were recorded in the designated memorandum account. The large electrical corporation may only seek recovery for costs recorded in the memorandum account by filing a Phase 3 Application. The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall not exceed the cap established for such accounts in the Phase 2 Decision. The purpose of any Phase 3 Application will be to determine whether the costs recorded in the memorandum account meet the conditions set forth in the "Conditions for Approval of Recorded Costs in Memorandum Account" section below. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. No more than one Phase 3 Application may be filed each year.

The elements of recorded costs must be consistent with the elements included in the costs presented in the Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all six-month progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following program data presented in Table 1 for the requested recovery period.[26] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet. Additional data requirements for a Phase 3 Application may be included in the Phase 2 Decision.

---

[26] Recovery period means the period under consideration in the most recent Phase 3 Application filing.

Table 1: Conditionally Approved Target and Actual Recorded Cost Data

Conditionally Approved Targets for the Recovery Period	Actual Recorded Costs in the Recovery Period
Program Cost	Program Cost
Program BCR	Program BCR
Program Unit Cost	Program Unit Cost
	Project Data for the Recorded Projects

Conditions for Approval of Recorded Costs in Memorandum Account:

To further protect ratepayers from unexpected and inefficient cost overruns:

1) The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.
2) When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.
3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless and until the large electrical corporation has shown that it has applied all third-party funding previously received to reduce its relevant balancing account cost cap.
4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless such costs are consistent with the approved Plan.

Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Accordingly, without affecting the required progress report elements specified by Energy Safety, these *Guidelines* require that the six-month progress reports shall include, but should not be limited to, the following:

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded BCR for completed projects in any given two-year period;
4) Average recorded unit cost per mile of undergrounding for completed projects in any given two-year period;
5) Miles of overhead replaced by undergrounding by circuit segment;
6) Miles of undergrounding completed by circuit segment;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format);
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements 19-21; and

9) Total and average avoided costs and workpapers showing calculation of avoided costs.
10) An updated dataset that follows the requirements of the *SB 884 Project List Data Requirements Guidelines*.

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2, as well as any other reporting requirements in the *Energy Safety Guidelines*, the Phase 2 Decision(s), and the Phase 2 Application Requirements listed above. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file, and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

Audit of the One-Way Balancing Account:

An audit of the one-way balancing account shall occur annually (hereafter, EUP Audit). The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit. Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all four[27] Phase 2 Conditions. The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in SPD-37:

1) Verify that projects are "used and useful;" and
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed through another decision, mechanism or received from a third party.

A Phase 1 Decision may also add primary and/or secondary objectives for the EUP Audit.

As for the specific method the auditor will use to verify whether the costs of underground projects recovered via the one-way balancing account met the primary and secondary objectives, such methodology will be determined via the Phase 1 Application process.

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in a future Commission Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[28] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be

[27] The EUP Audit scope will also include any Phase 2 Conditions adopted in a future a Commission Decision beyond those listed herein.

[28] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

filed and served in the Phase 2 Application docket no later than seven days (or such period specified in a future Commission Decision) after the due date for opening comments. The Commission may determine the appropriateness of reopening the Phase 2 Application proceeding based on its review as described below.

Following its review of the audit report, six-month progress reports, associated comments, and any petitions received, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

The large electrical corporation shall not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in a future Commission Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in a future Commission Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff understand that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[29] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December 1.[30] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[31] The large electrical corporation shall have 180 days to correct and eliminate any deficiency specified in the independent monitor's report.[32] Energy Safety shall consider

[29] Public Utilities Code, Section 8388.5(g)(1).

[30] Public Utilities Code, Section 8388.5(g)(3).

[31] Public Utilities Code, Section 8388.5(g)(1).

[32] Public Utilities Code, Section 8388.5(g)(2).

the independent monitor's compliance report and whether the large electrical corporation cured the deficiencies identified therein when making its determination on whether to recommend penalties to the Commission.[33]

Penalties:

Pursuant to Public Utilities Code, Section 8388.5(i)(2), the Commission may assess penalties on a large electrical corporation that fails to substantially comply with a Commission decision approving its Plan.

[33] Public Utilities Code, Section 8388.5(i)(1).

Appendix 1: SB 884 Project List Data Requirements Guidelines*

* The *SB 884 Project List Data Requirements Guidelines* were published by Safety Policy Division on July 24, 2025. Additional information, including the data template that large electrical corporations must use to file its Application and six-month progress reports can be found here: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884. The *SB 884 Project List Data Requirements Guidelines* presented here supersede Appendix 1 of Resolution SPD-15.

California Public
Utilities Commission

SB 884 Project List Data Requirements Guidelines

SAFETY POLICY DIVISION

July 24, 2025

Table of Contents

Background and Purpose:

Pursuant to Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), the California Public Utilities Commission's (CPUC or Commission) data requirements for a large electrical corporation's Electrical Undergrounding Plan (EUP) intended to mitigate wildfire risk in the High Fire Threat District (HFTD), will be complex and require coordination with the Office of Energy Infrastructure Safety's (Energy Safety) Guidelines and data templates. Attached to Resolution SPD-15,[1] the Commission issued the *SB 884 Project List Data Requirements-Preliminary* to begin the discussion on how a utility should submit tabular and geospatial data in support of a Phase 2 Application related to its EUP.[2] Ordering Paragraph 3 of SPD-15 stated that:

> Following Energy Safety's publication of its SB 884 Guidelines, SPD is authorized to convene a Technical Working Group (TWG) to review and align the preliminary CPUC SB 884 Project List Data Requirements and Geographic Information System (GIS) data requirements with Energy Safety Guidelines, adding any data elements necessary for Commission conditional approval purposes.

Additionally, Ordering Paragraph 4 of SPD-15 stated that:

> SPD is authorized to develop and issue the SB 884 Project List Data Template within 30 days of the final TWG meeting.

As discussed below, the final TWG meeting was held on June 24, 2025. Thus, by issuing the *SB 884 Project List Data Requirements Guidelines* (henceforth referred to as the *CPUC SB 884 Data Guidelines*) to the SB 884 Notification List on July 24, 2025, SPD has completed the requirements of Ordering Paragraph 4 in SPD-15.

On February 20, 2025, Energy Safety published Guidelines that a large electrical corporation must follow to submit an EUP to that agency.[3] Energy Safety's Guidelines include extensive discussion of data requirements that require the Commission to review and determine the best way to align its own data requirements for a large electrical corporation's Phase 2 Application for the EUP. Following the TWGs discussed below, the *CPUC SB 884 Data Guidelines* represents an alignment between the data needs of the Commission to evaluate conditional approval of costs and the requirements found in the Energy Safety Guidelines as was required by Ordering Paragraph 3 in SPD-15.

On January 30, 2025, Safety Policy Division (SPD) presented a Risk Assessment and Mitigation Phase (RAMP) data template Guidelines and data template as part of a TWG in Phase 4 of the Risk-Based Decision-Making Framework (RDF) Proceeding (R.20-07-013).[4] On February 11, 2025, an Administrative

---

[1] Resolution SPD-15 is available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/final-resolution-spd15-adopting-the-commissions-guidelines-for-the-senate-bill-sb-884-program.pdf.

[2] SPD-15, Attachment 1, Appendix 1 at 15-18.

[3] Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines, February 20, 2025, https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.

[4] The RAMP is a process a utility complies with before initiating a GRC that requires energy-utility safety-risk threat assessments along with associated proposed mitigation plans and estimated costs and spending requests. The RDF proceeding examines how

Law Judge Ruling filed SPD's RAMP data template Guidelines and data template to the RDF Proceeding[5] SPD recognizes that it will be crucial that a data template for a Phase 2 Application also align with the data template needed in a RAMP and General Rate Case (GRC) Application. The structure of the *CPUC SB 884 Data Guidelines* is influenced by the discussion of Staff's data template Guidelines presented in the RDF Proceeding.

Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" (or Staff Report) on May 20, 2025, which included a set of "Technical Working Group Questions". Commission Staff then hosted a series of three TWG meetings in June 2025. During the SPD TWG meeting #1, held on June 3, 2025, SPD Staff presented the Staff Report and addressed questions from stakeholders regarding potential updates to the SB 884 Project List Data Requirements. In a May 15, 2025, e-mail to the SB 884 Notification List, SPD offered the opportunity for any stakeholder to present their feedback and recommendations on the Staff Report. No stakeholders accepted this opportunity. However, Staff did receive a list of questions from Pacific Gas and Electric Company (PG&E), which it requested to be discussed during the SPD TWG meeting #2 on June 10, 2025. Additionally, the SPD TWG meeting #3 on June 24, 2025, included presentations from Lawerence Berkeley National Labs and PG&E on the Interruption Cost Estimate Calculator (ICE 2.0). Stakeholders held additional discussion related to the way ICE 2.0 was addressed within the Staff Report. Finally, Staff accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the adoption of the Energy Safety Guidelines, informs the *CPUC SB 884 Data Guidelines* presented in this document.

The purpose of the *CPUC SB 884 Data Guidelines* is to provide clarity on the field name, field description, and field value constraints in the SB 884 Project List Data Template. Additionally, the *CPUC SB 884 Data Guidelines* is a revision of *SB 884 Project List Data Requirements-Preliminary* that was attached to SPD-15.

For each project included in the Plan and Application, the large electrical corporation shall provide, at a minimum, all data listed in the *CPUC SB 884 Data Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *CPUC SB 884 Data Guidelines* at the time of its Application submission. Additionally, at a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the data required in the *CPUC SB 884 Data Guidelines.*[6] The data values provided in each update of the data required in the *CPUC SB 884 Data Guidelines* should correspond to the date listed in each of the Reporting_Date fields found at the end of Tables 1-6.

to calculate risk mitigation levels for various safety measures in order to ensure utilities focus on the most cost-efficient risk reduction strategies in their safety work, including wildfire-related safety.

[5] Administrative Law Judge's Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, February 11, 2025, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=556602565.

[6] Energy Safety Guidelines at 25-26.

Note on Terminology:

1. The term "Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the Energy Safety Guidelines.[7]

[7] The 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025, page A-4.

Template and Tables Structure

Table 1: Data Set

This table collects the key elements and characteristics of a Risk Reporting Unit (RRU), including unique identifiers, mitigation plans, and associated risks.[8] Table 1 defines how risk-related data elements are structured and categorized for consistent reporting across various progress reports and geographic locations.

As stated in the introduction, it is necessary to align the SB 884 Project List Data Template with the RAMP Data Template discussed in the RDF Proceeding.[9] Here we present a definition of asset, RRU, and system to clarify that these concepts must be shared across RAMP and SB-884 Applications.

- Asset: A retirement unit as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) that exhibits risk.[10]
- Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk. The RRU must include common elements that must include, but are not limited to Consequence Attributes, Risk level, line-item costs, benefit-cost ratios (CBRs), work units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to, hierarchy,[11] scenario,[12] version,[13] risk event, tranche, and mitigation type.
- System: A regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit.

Unless otherwise specified, such as certain fields in Table 4, all data requirements related to assets, RRUs, and systems apply to but are not limited to, primary, secondary and service lines.

Additionally, to conform with the requirements of the CPUC's SB 884 Guidelines found in SPD-15 or any successor Commission order or decision, the RRU must be:

1. Traceable through all stages of a lifecycle, including but not limited to the project's scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.
2. Auditable in terms of timing, location, work units, costs, and Risk Reduction.
3. Forecastable to at least the 10th year of the EUP.

---

[8] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024.

[9] Any updates in the RDF Proceeding may result in an update in the SB-884 Data Template Guidelines.

[10] For the FERC USOA, see 18 CFR Part 101 https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

[11] Hierarchy refers to a utility's organizational hierarchy, such as an Electric Distribution Division or a Gas Distribution Division. as well as other ways of categorizing high risk assets and systems (i.e. HFTDs, circuits, regions, etc.).

[12] Scenario refers to forecasts, results, and projections.

[13] Version refers to a risk model version.

4. Able to aggregate up to the EUP.[14]

Utilities shall use these definitions and requirements to present RRU level data in their EUP. The level of granularity required is discussed below.

Tables 1 through 4 are anchored around the RRU_ID field, which references uniquely identifiable RRUs with unique identification numbers (i.e., IDs). A utility's RRU_ID naming schema must be simple and transparently understandable. A utility's RRU_ID naming schema must include the GRC Activity Code of the Undergrounding Project, which must also be listed in Table 1. A utility's RRU_ID naming schema must not result in the reuse of an RRU_ID.

Table 1 shall be submitted with the Phase 2 Application and all subsequent progress reports. In cases where RRU_IDs have not yet been created for certain projects, for the reasons outlined below, the table must be submitted using the corresponding OEIS_Project_ID.[15] Once more detailed and updated information becomes available, reporting in six-month progress reports shall transition to the RRU_IDs. The utility must continue reporting OEIS_Project_IDs to enable traceability and continuity across reports.

The fields OEIS_Project_ID and OEIS_Subproject_ID directly align to the Energy Safety Guidelines and enable coordination with the data templates submitted with the EUP to Energy Safety.[16] All requirements found in the Energy Safety Guidelines for OEIS_Project_ID and OEIS_Subproject_ID also apply to this data template.

If the utility submits a Phase 2 Application that does not use Subprojects, then the Commission requires that the granularity of the RRU be identical to that of the Project as defined in the Energy Safety Guidelines (see Figure 1). If the utility submits a Phase 2 Application that uses Subprojects the Commission requires that the granularity of the RRU be identical to that of the Subproject once detailed Subproject data is available, which means that each RRU_ID can only be tied to a single OEIS_Subproject_ID (Figure 2). Once an RRU_ID is created for a Subproject, all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

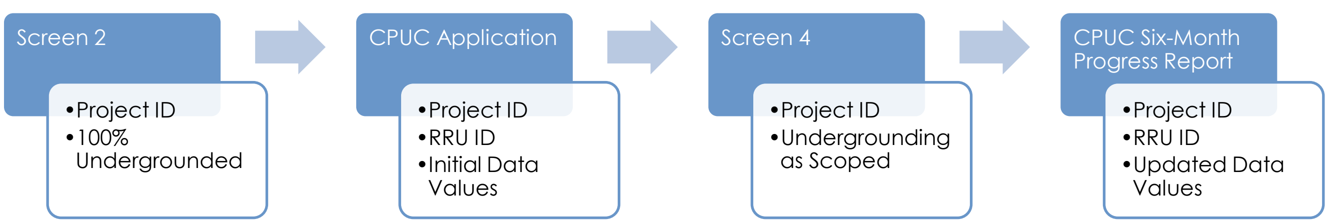

Figure 1: Process for creating an RRU_ID and Data Submissions for Phase 2 Application without Subprojects

[14] These three requirements have been adapted from the Staff Scoped Work Proposal to conform to the requirements of the SB-884 program.

[15] OEIS_Project_ID corresponds to project_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-24).

[16] OEIS_Subproject_ID corresponds to subproject_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-36).

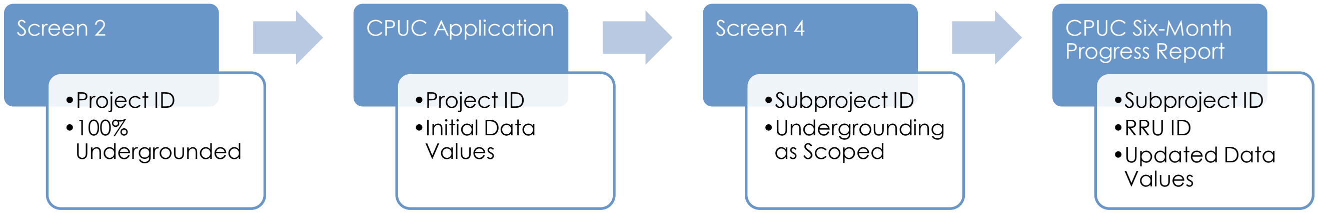

Figure 2: Process for creating an RRU_ID and Data Submissions for Phase 2 Application with Subprojects

If the utility elects to use Subprojects in its Phase 2 Application, then when the utility submits its Phase 2 Application to the Commission, it is possible that detailed Subproject level forecasts may not be available. In the case where the utility submits a Phase 2 Application that uses Subprojects and the Subproject level forecasts are not available, for the initial dataset submitted with the utility's Phase 2 Application, the utility may present forecasts at the Project Level, which should correspond with the Screen 2 data presented by the utility in Table C.11 of the Energy Safety Guidelines.[17] The forecasts presented at the Project Level in the initial dataset submitted with the Application will correspond to the "100% Undergrounded" concept defined in the Energy Safety Guidelines.[18] The RRU_ID field may be left blank at this point. Once detailed Subproject data is available, an RRU_ID must be created for each Subproject, and all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

When the utility submits its Phase 2 Application or six-month progress reports to the Commission, it is required that for any Project (i.e., OEIS_Project_ID) that passes Screen 4 of the Energy Safety Guidelines, the utility shall provide data values in the Commission's data template that should correspond with the Screen 4 data presented by the utility in Table C.13 of the Energy Safety Guidelines.[19] If the utility submits a Phase 2 Application that uses Subprojects, then the detailed RRU level data values submitted to the Commission should correspond with the Subproject data presented by the utility in Table C.14 of the Energy Safety Guidelines.[20]

If the Project has passed Screen 4 of the Energy Safety Guidelines, then the information presented at the Project or Subproject Level in the dataset submitted with either the Phase 2 Application or the six-month progress reports will correspond to the "Undergrounding as Scoped" concept defined in the Energy Safety Guidelines.[21]

For utilities that submit Projects in their Phase 2 Application and do not plan to break them into Subprojects later, the utility may continue reporting data at the Project level throughout both the Phase 2 Application and subsequent six-month progress reports. In these cases, the utility must still align its data with the appropriate Energy Safety Guidelines tables initially using Table C.11 for Screen 2 forecasts and then updating with Table C.13 data for Projects that pass Screen 4. RRU_IDs shall be created for the

[17] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-25 – C-26.

[18] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

[19] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-30 – C-32.

[20] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-33 – C-35.

[21] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

Project, and all reporting remains at the Project level. All data must be reported using the unique RRU_ID and OEIS_Project_IDs from the Phase 2 Application. (Figure 2)

Table 1 also collects Backcasted_Cost_Benefit_Ratio, Backcasted_Total_Mitigation_Benefit and Backcasted_Present_Value_Costs. In order to align with the concept of a Backcast as discussed in the RDF Proceeding, the following definition applies:

- Backcast: use updated inputs (e.g., new RRUs, new risk models) to recalculate Cost-Benefit Ratios, pre-mitigated risk, post-mitigated risk or other data elements. The goal of a Backcast is to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison.

When a utility elects to use the Subproject designation, the concept of a Backcast is essential in the SB-884 context to enable a consistent comparison between the forecasted RRU values reported in the progress reports and the backcasted RRU values that would have been calculated, had the RRU structure been applied in the Phase 2 Application using the data submitted at that time. For a utility that elects to use the Subproject designation the Backcasted_Total_Mitigation_Benefit, Backcasted_Present_Value_Costs and Backcasted_Cost_Benefit_Ratio fields may be left blank in the Phase 2 Application for OEIS_Project_IDs that have yet to establish an RRU_ID. For a utility that elects to align an RRU_ID with the OEIS_Project_ID (i.e. does not use the Subproject designation) there is no need to complete the Backcasted_Total_Mitigation_Benefit Backcasted_Present_Value_Costs, and Backcasted_Cost_Benefit_Ratio fields.

Table 1 also collects Unit_Cost_Percentage_Difference, calculated as:

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} - \text{Updated Unit Cost in progress report}}{\text{Initial Forecasted Unit Cost in Phase 2 Application}}$$

Where "Unit Costs" refers to the Average_Unit_Cost_per_Mile in Table 1

and also

CBR_Percentage_Difference calculated according to the following two scenarios:

a- Assuming the large electric corporation elects to use the Subproject designation and detailed Subproject data is not available, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and updated Cost_Benefit_Ratio in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Backcasted\_Cost\_Benefit\_Ratio} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Backcasted\_Cost\_Benefit\_Ratio}}$$

b- Assuming the large electric corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application, this is calculated as the percentage difference forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Cost\_Benefit\_Ratio in Phase 2 Application} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Cost\_Benefit\_Ratio in Phase 2 Application}}$$

These two fields provide insight into the extent to which the CBR and Unit Cost have deviated from their original forecasted values, allowing for a clearer assessment of project performance and cost-effectiveness over time.

In Table 1, for each RRU (or project)[22] there will be one row for the utility's Undergrounding mitigation and one separate row for each alternative.[23]

All the Post-Mitigation fields must be completed by the utility using Screen 2 data or more updated data if available in the utility's Phase 2 Application. If the utility has data for scoped projects that have passed Screen 3 at the time of submitting its Phase 2 Application, then it must use that data. These fields will be updated by the utility in six-month progress reports as Screen 3 data becomes available.

For each RRU (or project), there should be one row representing the utility's undergrounding mitigation and one row for each alternative mitigation. Since each of these mitigation programs must be evaluated using three separate discount rates scenarios, this results in a total of nine rows per RRU (or project).

Table 2: Capital Cost Breakdown

This table breaks down the Capital Costs associated with mitigation efforts, including labor, materials, and permits, for projects under the Risk Reporting Unit. It provides detailed cost allocation to track expenditure efficiently. Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above.

Table 3: Risk Model Change Tracker

This table tracks changes and updates to the risk modeling and how that affects the risk associated with the assets and systems mitigated by the RRUs. Changes that include New Data Inputs to the Risk Model can include, but are not limited to, the addition of climate change variables or wildfire suppression related information. This allows us to compare current and previous risk models, risk scores and Costs across each of the six-month progress reports. It ensures transparency and accountability in how risks related to the electric grid are managed and reported.

Utilities regularly update their risk models. At times, the outputs (calculated risks) of new risk model versions might be substantially different from the previous version(s). In some cases, utilities have changed the length and names of each circuit segment from one risk model to another. To address the lack of clarity of the impact caused by changing risk models between the six-month progress reports, SPD created a template (Table 3) to track changes in each RRU (or Project) and how those changes would impact the calculation of risk from one risk model to the next. Table 3 collects data regarding changes in calculated risk, length, and name of each RRU (or Project), which utilities plan to include in its undergrounding projects. This enables analysis and comparison of data created across different risk models and supports comparison of such data across the six-month progress reports and even maybe among various proceedings where such data may be presented. Data

---

[22] Data may be submitted at the project level in the initial Application and at RRU level in subsequent progress reports when RRUs are created as described at page 4-5. This requirement follows for any other location in these Guidelines that state "RRU (or Project)".

[23] Please see the Proposed and Alternative Mitigations field described below and in the Excel data template attached to this Guideline.

may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above. This table complements some of the information presented in Table C.7 of the Energy Safety Expedited Undergrounding Plan Guidelines.[24]

Table 4: HFTD and Associated Asset

This table documents low-risk associated assets mitigated alongside primary electric grid infrastructure due to operational constraints or interconnected systems.[25] It includes associated Costs, miles, and Total Mitigation Benefit for comprehensive project management of risk on electric grid infrastructure.

Table 4 attempts to collect and clarify information regarding how the additional electric grid infrastructure associated assets can affect the Total Mitigation Benefit, Capital Costs, and CBR of the proposed RRU (or Project).-Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above

Table 5: Financial Inputs

This table provides financial parameters and metrics required to calculate and evaluate risk mitigations, including discount rates, the value of statistical life (VSL), and Present Value revenue requirements (PVRR). These inputs ensure that economic factors are systematically integrated into risk evaluations.

Table 6: Interruption Cost Estimate (ICE) Calculator Inputs

Since SB-884 requires undergrounding projects to be completed within the HFTD, the ICE Calculator inputs must be relevant only to the HFTD. The utility must also disaggregate their inputs according to HFTD and non-HFTD regions. This table provides inputs that can be integrated into the ICE Calculator 2.0 to estimate the cost per customer-minute interruption, by categorizing outages by time of day, season, and customer type. The ICE Calculator integrates key reliability metrics such as SAIDI and SAIFI to estimate the impact of service interruptions. This table requires the utility to calculate the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields as a $/CMI value which is further used to calculate the monetized value of electric reliability consequence within the HFTD.[26]

---

[24] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-12 – C-14.

[25] In Table 4, “low-risk” is defined as electric grid infrastructure assets whose risk level is below the “High-Risk Threshold” defined by Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, page 42.

[26] The calculation of Pre-mitigated and Post-mitigated Ignition and Outage Program Risk must include Pre-mitigated and Post-mitigated monetized values of electric reliability consequence, which must be calculated as a product of the $/CMI values from the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields in Table 6 and the following corresponding eight fields:

1. Ignition_Pre_Mitigated_Residential_Reliability_Consequences
2. Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences
3. Ignition_Post_Mitigated_Residential_Reliability_Consequences
4. Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences

Table Relationships

The data template Guidelines uses three primary key fields, RRU_ID, OEIS_Project_ID, and Undergrounding_Alternative_Mitigations, to connect Tables 1, 2, and 4 and ensure data consistency.
Every row in Tables 2 and 4 must correspond to a matching row in Table 1 using these fields. This structure supports accurate cost allocation, risk modeling, and asset tracking.
Table 3 uses RRU_ID and OEIS_Project_ID as its primary keys, which can be linked to Tables 1, 2, and 4 when tracking changes to risk models or asset definitions.

---

5. Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences
6. Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences
7. Outage_Program_Post_Mitigated_Residential_Reliability_Consequences
8. Outage_Program_Post_Mitigated_Non_Residential_Reliability_Consequences

Tables and Data Requirements

Table 1: Data Set

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the Risk Reporting Unit (RRU).[27]	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. OEIS_PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Circuit_Segment_ID	A unique value identifying the Circuit Segment ID on which this Undergrounding Project was defined. This is the same value as found in the Energy Safety Guidelines. If the Circuit Segment changes, the Circuit_Segment_ID remains identified with the original Circuit Segment, at the point the OEIS_PROJECT_ID is created	VARCHAR (255)
QDR_Circuit_Segment_ID	If the Circuit Segment was included in the most recent Quarterly Data Report submission as part of the WMP process, list the name used in that report. This must be the same value as found in the Energy Safety Guidelines in Table C.6.	VARCHAR (255)
GRC_Activity_Code	This is the Activity Code for the Proposed Mitigation relevant to this RRU. Field values are expected to utilize the following notational systems: PG&E: Maintenance Activity Type (MAT) SCE: Work Breakdown Structure (WBS) Sempra: Capital Programs are defined at the budget code; Expense programs are defined at the workpaper.[28]	VARCHAR (255)

[27] For more information see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20. See also the discussion in R.20-07-013, Phase 4 Workshop 3, SPD Staff Proposal on Risk Mitigation Accountability Reports December 30 2024at 22.

[28] D.24-05-064, Appendix A, Row 28.

Field Name	Field Description	Field Value Constraints
Filings	List of all filing(s), including advice letters, where the RRU (or Project) is reported and a budget is requested including but not limited to a GRC application and Wildfire Mitigation and Catastrophic Events (WMCE) application.	TEXT
Customer_Count_Residential	Number of Residential customers served by the RRU (or Project)	INT
Customer_Count_Non_Residential	Number of Non-Residential customers served by the RRU (or Project)	INT
State_Legislative_District	State Legislative District of the service territory in which the RRU (or Project) is located.	VARCHAR (255)
Tranche_Level	The Tranche that includes the Assets or Systems that the Project[29] mitigates. Each Project can only mitigate the risk exhibited by Assets or Systems found in one Tranche. Tranches are the quintiles of Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE) for Wildfire Ignition Risk. The structure of the Tranche level to record in this field is represented as LoRE quintile and CoRE quintile that make up each tranche. Thus, the Tranche Level should be presented in the following shorthand: CoRE 1×LoRE 2 or CoRE 2×LoRE 1 If the utility has presented an alternative approach to tranches via a whitepaper in a previous RAMP Proceeding, it must create a clear and concise shorthand for the structure of the tranches.[30]	VARCHAR (255)

[29] Projects or RRUs reported in the Phase 2 Application. For any Projects reported in the Phase 2 Application, the corresponding RRUs are presumed to fall within the same Projects' Tranches.

[30] For more detail on the Tranche Level field, see D.24-05-064 at 26-33 and D.24-05-064, Appendix A, Row 14. Even if the utility records a Tranche Level in this field that accords with the tranche structure in its alternative approach to tranches, SPD reserves its right to challenge any alternative approach to tranches (See D.24-05-064 at 31).

Field Name	Field Description	Field Value Constraints
Asset_System_List	List of the unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU(or Project).[31] This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans. This field should also include the List of Associated Assets, if any, found in Table 4.	TEXT
Total_Circuit_Miles	Total number of pre-mitigated circuit miles included in the RRU (or Project).	REAL
Total_Circuit_Miles_UG	Total number of post-mitigated undergrounded circuit miles included in the RRU (or Project). This field only applies if Undergrounding_Alternative_Mitigations is listed as undergrounding mitigation.	REAL
Risk_Ranking	Ranking of the total pre-mitigated risk that is exhibited by the assets or systems that the RRU (or Project) mitigates (E.g., where the risk level of the assets or systems mitigated by the RRU (or Project) lies in comparison with risk level of the assets or systems mitigated by other RRUs (or Projects) across the entire Proposed Mitigation Program).	VARCHAR (255)
Scoping_Date	The year, month and day the utility intends to begin or did begin the scoping process of this mitigation for the RRU (or Project).	Date (YYYY-MM-DD)[32]
Start_Date	The year, month and day the utility intends to begin or did begin the construction or implementation of the RRU (or Project).	Date (YYYY-MM-DD)[33]
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following risk and cost analyses are carried out based on the value inputted within this field.[34] This field enables comparison of risk and cost analyses of alternative mitigations and the proposed undergrounding program for the same RRU (or Project).	VARCHAR (255)

[31] Asset is a retirement unit that exhibits risk, as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). A System is defined as a regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit. See R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20.

[32] If the year, month and day is available, the utility must record this information in this field using the YYYY-MM-DD format.

[33] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

[34] For more information on alternative mitigation analysis, see D.18-12-014 at 34.

Field Name	Field Description	Field Value Constraints
Undergrounding_Mitigation_Justification1	Primary reason for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold; the Ignition Tail Risk Threshold, the High Frequency Outage Program Threshold, operational limitations, cost efficiency, and continuity.	VARCHAR (255)
Undergrounding_Mitigation_Justification2	Other reasons for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold, the Ignition Tail Risk Threshold; the High Frequency **Outage** Program Threshold, operational limitations, cost efficiency, and continuity. If a utility does not have a secondary reason for choosing the Undergrounding mitigation the utility should leave this field blank.	VARCHAR (255)
Status	Preset domain values to identify the current status of the RRU (or Project) are:[35] • Scoping: Identifying the size and timeline of the RRU (or Project) Scoping is the first step to providing visibility to the construction feasibility and possible execution timing. Designing: Delineation of a plan for implementing the RRU (or Project) including determining the RRU's (or Project) integration within existing infrastructure or operations and need for materials, training, or permitting. The costs for completing the RRU (or Project), including for permitting, labor and materials, are forecasted at this stage. • Permitting: The process of obtaining the rights and permits from relevant stakeholders to implement the RRU (or Project). This stage of the lifecycle also includes negotiating of contracts to implement the RRU (or Project) as well as final estimation of the costs associated with implementing the RRU (or Project).	VARCHAR (255)

[35] Information about the Status field can also be found in R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 10-11.

Field Name	Field Description	Field Value Constraints
	• Construction/Implementation: During this stage a capital investment is built out or an operational activity is put into action. Capital investments are complete when they are used and useful. Operational activities could be an ongoing means of maintaining a level of risk.[36] • Post-Construction: For capital investments, there can be final paperwork and updates to asset registries after the scoped work is used and useful.[37]	
Used_and_Useful_Date	The year, month and day the utility intends to make or did make this RRU (or Project) used and useful. Used and useful means to be fully complete and providing service to customers.	Date (YYYY-MM-DD)[38]
CBR_Year_Zero	The year the risk and costs for the Undergrounding_Alternative_Mitigations program for the RRU (or Project) are discounted to.	INT
Useful_Life	The value of the useful life of the Undergrounding_Alternative_Mitigations program, represented as the number of years.	REAL
Ignition_Pre_Mitigated_Likelihood	The likelihood of Ignition before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL

[36] The "Construction/Implementation" status value corresponds to the "Ready for Construction" and "Construction in Progress" values in table C-14 of the *Energy Safety Guidelines*.

[37] The "Post-Construction" status value corresponds to the "Construction Completed" and "Overhead De-energized" values in table C-14 of the *Energy Safety Guidelines*.

[38] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

Field Name	Field Description	Field Value Constraints
Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Likelihood	The likelihood of Ignition occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Likelihood	The likelihood of Outage Program occurring before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Likelihood	The likelihood of Outage Program occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Outage_Program_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL
Outage_Program_Post_Mitigated_Non_Resdiential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Pre_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Total_Mitigation_Benefit, Present_Value_Capital_Costs, and Cost_Benefit_Ratio, among others. Input in this field shall include one row for each of the following three discount rate scenarios: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Ignition_Risk_Mitigation_Benefit	Present Value of the Wildfire Ignition Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Outage_Program_Risk_Mitigation_Benefit	Present Value of the Outage Program Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL

Field Name	Field Description	Field Value Constraints
Net_OM_Costs_PV	Present Value of Operations and Maintenance (O&M) Cost Savings minus Present value of O&M New Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). Utilities may include Present Value of Net O&M Costs[39]as part of the Total_Mitigation_Benefit in the CBR's numerator for the RRU (or Project). (Dollar Value)	
Total_Mitigation_Benefit	Present Value of the Risk Reduction and potentially the Present Value of Net O&M Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Average_Unit_Cost_per_Mile	The average Unit Cost of the Undergrounding_Alternative_Mitigations program for the RRU (or Project) per mile.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Present_Value_Capital_Costs	Present Value of the Capital Costs (Total_CapEx) of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Cost_Benefit_Ratio	Cost-Benefit Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	REAL
Backcasted_Total_Mitigation_Benefit	Recalculated Total_Mitigation_Benefit from the Undergrounding and Alternative Mitigations measure submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Backcasted_Present_Value_Capital_Costs	Recalculated Present_Value_Capital_Costs of the Proposed and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL

[39] The CBR calculation shall only be based on the incremental difference between the proposed project and the No-Build Baseline, both in terms of benefits and net costs (Net O&M Costs). No-Build Baseline represents a well-defined baseline scenario or what happens if no project or RRU is implemented.

Field Name	Field Description	Field Value Constraints
Backcasted_Cost_Benefit_Ratio	Recalculated Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Unit_Cost_Percentage_Difference	The percentage difference between forecasted Average_Unit_Cost_per_Mile submitted in the Phase 2 Application and updated Unit Costs in the subsequent six-month progress reports.	REAL
CBR_Percentage_Difference	If the utility elects to use the Subproject designation, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and the Cost_Benefit_Ratio presented in the subsequent six-month progress reports. If the utility elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application this is calculated as the percentage difference between forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent six-month progress reports.	REAL
Risk_Model	Name and Version of Risk Model used to calculate Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	VARCHAR (255)
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 2: Cost Breakdown

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
CapEx_Labor	Including all the required Engineering, Design, and Construction.	REAL
CapEx_Materials	All the required material s.	REAL
CapEx_Permits_Environmental	Permitting fees from local and state agencies that cover, for instance, but not limited to, environmental impact assessments.	REAL
CapEx_Other_Costs	Other Capital Expenditure that are not categorized in the rows above.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations for the RRU. This value must be equal to Total_CapEx fields in Table 1.	REAL
Initial_Application_Total_Costs	Total nominal value of the Total_CapEx of the Undergrounding_Alternative_Mitigations for the RRU (or Project) that was presented in the Phase 2 Application to the Commission. This field should remain blank when the utility submits its Phase 2 Application.	REAL

Field Name	Field Description	Field Value Constraints
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 3: Risk Model Change Tracker

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Current_Asset_System_List	List of current unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU (or Project). The list in this field must be the same as the list in the Asset_System_List field in Table 1. This should include, but not limited to, the following examples: This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Current_Risk_Model	Name and Version of the updated Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project). (E.g., V2)	VARCHAR (255)
Current_Total_Miles	Total circuit miles under Current Risk Model for the RRU (or Project). This must be the same as the Total_Circuit_Miles in Table 1.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Current_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Current Risk Model for the RRU (or Project).	VARCHAR (255)
Current_Pre_Mitigated_Overall_Utility Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Current Risk Model. (Dollar Value). This must be the same as the Pre_Mitigated_Overall_Utility_Risk field presented in Table 1.	VARCHAR (255)
Current_Risk_Percentage	The Pre_Mitigated_Overall_Utility_Risk risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Current Risk Model.	VARCHAR (255)
Change_Type	Identification of how the circuit segment or partial circuit segment mitigated by the RRU has been defined and redefined since the last update: • New Data Inputs to Risk Model • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment • Merging of the circuit segment or partial circuit segment • Other	VARCHAR (255)
Change_Date	Date the Change_Type was implemented on the RRU (or Project).	Date (YYYY-MM-DD)

Field Name	Field Description	Field Value Constraints
Previous_Asset_System_List	For each RRU (or Project), if the value in the Change_Type field in this Table is one of the following: • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment Merging of the circuit segment or partial circuit segment Then list the unique Assets and/or the unique Systems mitigated by the RRU(or Project), prior to the Change_Date. This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Previous_Risk_Model	Name and Version of the previous Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project).	VARCHAR (255)
Previous_Total_Miles	Total circuit miles under the Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Pre_Mitigated_Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Previous Risk Model. (Dollar Value)	VARCHAR (255)
Previous_Risk_Percentage	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Previous Risk Model.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Initial_Application_Total_Miles	Total number of circuit miles included in the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Initial_Application_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) for the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Reporting_Date	The date the risk and costs associated with the Current Risk Model are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs associated with the Current Risk Model are calculated.	Date (YYYY-MM-DD)

Table 4: HFTD and Associated Asset

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost and risk analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
Associated_Assets	List of all connected low-risk Associated Assets that the utility plans to mitigate because of operational constraints or reasons other than the reducing risk (e.g., Service lines and Secondary lines).	TEXT
HFTD_Tier2_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 2.	REAL
HFTD_Tier3_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 3.	REAL
Wildfire_Rebuild_Miles	If applicable, the total number of miles included in the RRU (or Project) located in the Wildfire Rebuild Area.	REAL
Associated_Asset_Miles	Total associated asset miles included in the RRU (or Project) that the utility plans to mitigate.	REAL

Field Name	Field Description	Field Value Constraints
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Associated_Assets_Total_Mitigation_Benefit, and Associated_Assets_Present_Value_Capital_Costs, among others. Input in this field should be one of the following: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Associated_Assets_Present_Value_Capital_Costs	The Present Value of Capital Costs of the Undergrounding and Alternative Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Associated_Assets_Total_Mitigation_Benefit	The Present Value of the Risk Reduction and possible Present Value of Net O&M Costs of the Undergrounding_Alternative_Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Reporting_Date	The date the risk and Costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 5: Financial Inputs

Field Name	Field Description	Field Value Constraints
WACC_Discount_Rate	The Weighted Average Cost of Capital (WACC) Discount Rate Scenario the utility must use to calculate Present Value Benefits and Costs component of the CBR for an RRU (or Project).[40]	REAL
Societal_Discount_Rate	The Societal Discount Rate Scenario the utility must use to calculate the Present Value of Benefit and Costs component of the CBR for an RRU (or Project).[41]	REAL
VSL	Dollar value of statistical life used to monetize the Safety Consequence.[42]	REAL
Financial	Dollar value used to monetize the Financial Consequence, and it equals to $1.	REAL
PVRR	If applicable, PVRR or Present Value Revenue Requirement is the financial metric the utility used in its rate case and long-term planning to evaluate the cost implications of investments or programs over the life of the asset. Providing the PVRR is optional.	REAL
ICE_Calculator_Version	The ICE Calculator version that utility uses to estimate dollar value per customer minute interrupted	REAL
Reporting_Date	The date the Financial Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the financial Inputs are calculated	Date (YYYY-MM-DD)

[40] D.24-05-064 at 103.

[41] D.24-05-064 at 102-103.

[42] D.22-12-027, OP 2a.

Table 6: Interruption Cost Estimate Calculator Inputs[43]

Field Name	Field Description	Field Value Constraints
HFTD_Region	Interruption Cost Estimate calculator inputs broken down by HFTD and Non-HFTD. Acceptable values are: • HFTD • Non-HFTD	VARCHAR (255)
Affected_Customers_Residential	Total number of residential customers affected by risk events by HFTD_Region	REAL
Affected_Customers_Non_Residential	Total number of non-residential customers affected by risk events by HFTD_Region	REAL
Average_Annual_Usage_Residential	Average annual electricity usage in kilowatt-hours for residential customers by HFTD_Region	REAL
Average_Annual_Usage_Non_Residential	Average annual electricity usage in kilowatt-hours for non-residential customers by HFTD_Region	REAL
Residential_BUG	Percentage of residential customers with backup generation by HFTD_Region	REAL
Residential_work_from_Home	Percentage of residential customer working from home by HFTD_Region	REAL
Non_Residential_Manufacturing	Percentage of non-residential customers engaged in manufacturing by HFTD_Region	REAL
Non_Residential_Health_Social	Percentage of non-residential customers engaged in health care and Social Assistance by HFTD_Region	REAL
Outage_Summer	Percentage of outages occurring in the Summer, from June through September by HFTD_Region	REAL
Outage_Weekend	Percentage of outages occurring at the weekend by HFTD_Region	REAL

[43] D.22-12-027, OP 2b.

Field Name	Field Description	Field Value Constraints
Non-Residential_Advanced_Warning	Percentage of customers with advanced warning of an outage by HFTD_Region	REAL
SAIDI	System Average Interruption Duration Index by HFTD_Region. It is calculated by dividing the total minutes of customer interruptions by the total number of customers served.	REAL
SAIFI	System Average Interruption Frequency Index by HFTD_Region. It is calculated by dividing the total number of customer interruptions by the total number of customers served.	REAL
Electric_Reliability_Valuation_Residential	The Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator for each **HFTD_Region.**	REAL
Electric_Reliability_Valuation_Non_Residential	The Non-Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator by **HFTD_Region.**	REAL
Reporting_Date	The date the ICE Calculator Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the ICE Calculator Inputs are calculated	Date (YYYY-MM-DD)

Appendix 2: Statutory Requirements Cross-Reference

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(a)	The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section.	Purpose (p. 1), and Background (p.2)
8388.5(e)(1)	Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following:	Background (p.2), and Phase 2 - Application Submission and Review (p. 8)
8388.5(e)(1)(A)	Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan.	Application Requirements (p. 9)
8388.5(e)(1)(B)	The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.	Application Requirements (p. 10)
8388.5(e)(1)(C)	How the cost targets are expected to decline over time due to cost efficiencies and economies of scale.	Application Requirements (p. 10)
8388.5(e)(1)(D)	A strategy for achieving cost reductions over time.	Application Requirements (p. 10)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(e)(3)	In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening.	Application Requirements (p. 9)
8388.5(e)(4)	Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days.	Public Workshop & Comments (p. 13)
8388.5(e)(5)	On or before nine months, the commission shall review and approve or deny the application. Before approving the application, the commission may require the large electrical corporation to modify or modify and resubmit the application.	Background (p.2), and Application Conditional Approval, Denial, or Modification & Resubmittal (p. 5)
8388.5(e)(6)	The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable.	SB 884 Program Process and Requirements (p. 4-5), Conditions for Approval of Plan Costs (p. 13), Phase 3 (p.14), and Audit of the One-Way Balancing Account (p. 16)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(i)(2)	The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan.	Background (p. 2), and Penalties (p. 17)
8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Background (p. 2), Application Requirements (p. 10), Conditions for Approval of Plan Costs (p. 12), Conditions for Approval of Recorded Costs in Memorandum Account (p. 15), and Progress Report (p. 18)

ATTACHMENT B

SB 884 Program: CPUC Guidelines (Rev 3 Redlined Version)

California Public Utilities Commission

SB 884 Program: CPUC Guidelines

SAFETY POLICY DIVISION

~~August 15~~December 10, 2025

Table of Contents

Purpose:

These *Guidelines,* and the adopting Commission Resolution, satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution infrastructure undergrounding program consistent with Senate Bill (SB) 884.~~)~~[1] These *Guidelines* address the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (as defined below) and related costs.

[1] McGuire; Stats. 2022, Ch. 819

Background:

SB 884, effective January 1, 2023, authorizes electrical corporations with 250,000 or more customer accounts within the state (i.e., large electrical corporations) to participate in an expedited utility distribution infrastructure undergrounding program.

To participate in the program, the large electrical corporation must submit a 10-year distribution infrastructure undergrounding plan (hereafter, "Plan" or "EUP"), including, among other requirements, the undergrounding projects to be constructed as part of the Plan, to the Office of Energy Infrastructure Safety (Energy Safety). Energy Safety is required to review and approve or deny the Plan within nine months of submission. Energy Safety may require the large electrical corporation to modify the Plan before approving it. Energy Safety may only approve the Plan upon finding it will achieve, at least, both of the following:[2]

1) Substantially increase reliability by reducing use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and other outage programs.
2) Substantially reduce wildfire risk.

The large electrical corporation must submit to the Commission, within 60 days of Energy Safety's approval, a copy of the Plan and an application requesting review and conditional approval of the Plan's costs (hereafter, "Application"). However, prior to formally filing the Application with the Commission, the large electrical corporation shall provide a copy of the Application it intends to file to the Commission's Safety Policy Division (SPD) for a completeness review to identify any obvious omissions or errors in the intended Application. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected before the Application is officially submitted and filed with the Commission.

On or before nine months after the Application's official filing date, the Commission shall review and conditionally approve or deny the Application. The Commission may, however, require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application prior to conditional approval. As further explained below, if the Commission or staff determines that minor corrections or clarifications are needed for the filed Application, the large electrical corporation may be required to modify the Application and provide corrections or clarifications within five (5) business days after being noticed. If the Commission or staff determines the filed Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, the Commission or staff may then require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for Commission review.

If the Plan is approved by Energy Safety and the Application requesting review and conditional approval of the Plan's costs is approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to

[2] Energy Safety has issued guidelines detailing the requirements for submission and review of undergrounding Plans. See https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true

review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

The independent monitor must annually produce and submit a report to Energy Safety no later than December 1 of each year over the course of the Plan.[3] The independent monitor's report will identify any failure, delays, or shortcomings in the large electrical corporation's compliance with the Plan and provide recommendations for improvements. After consideration of the independent monitor's report and whether the large electrical corporation has corrected the deficiencies identified therein, Energy Safety may recommend penalties to the Commission. The Commission may assess penalties on a large electrical corporation that fails to substantially comply with the Commission decision approving its Plan pursuant to Public Utilities Code, Section 8388.5(i)(2).

Figure 1 below shows an overview of the timelines, events, and responsible parties for implementation of the SB 884 program.

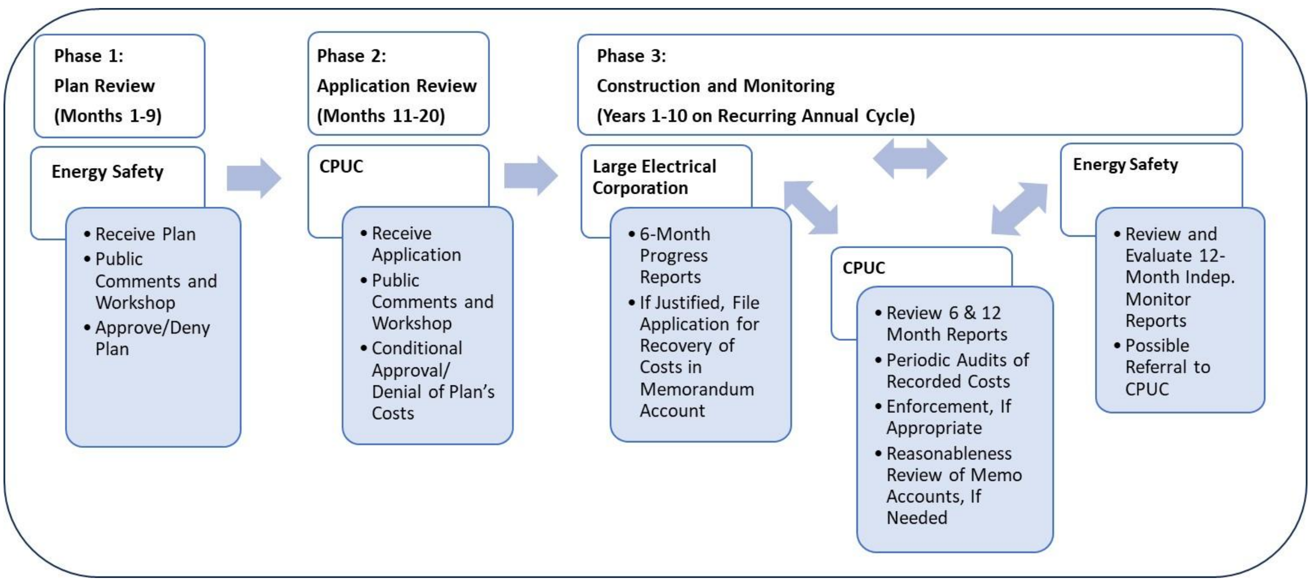

Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline

[3] Pursuant to Public Utilities Code, Section 8388.5(h), Energy Safety is required to publish these reports on its website.

SB 884 Program Process and Requirements:

The SB 884 Program will be executed in up to three phases:

- Phase 1 in two parts:
    - Energy Safety Plan review and approval/denial.
    - Joint Phase 1 Application from large electrical corporations to resolve issues identified in Resolution SPD-37, filed with Commission.
- Phase 2: Application submitted to Commission for review and conditional approval.
- Phase 3: Construction and periodic audits of costs recorded in the one-way balancing account, as well as just and reasonableness reviews of recorded costs in the memorandum account described below.

If Energy Safety approves the large electrical corporation's Plan in Phase 1, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial) via a Phase 2 Decision. The Commission will review the costs submitted in any Application. Only if costs[4] meet certain conditions (Phase 2 Conditions), will the Commission authorize their recovery via a one-way balancing account, which shall remain subject to audit. If an audit demonstrates any costs recorded to the one-way balancing account did not meet the Phase 2 Conditions, subject to Commission review and determination, such costs may be subject to refund. The Phase 2 Conditions for recovering costs via the one-way balancing account will include those listed in the "Conditions for Approval of Plan Costs" section herein, as well as any other conditions the Commission deems appropriate in the relevant Application's proceeding. If the Commission approves cost recovery in the one-way balancing account, the Commission will also authorize the large electrical corporation to record, in a memorandum account, any Plan costs that fail to meet the Phase 2 Conditions.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's issuance of the Phase 2 Decision. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program. The large electrical corporation shall also report on its progress and begin booking costs to the one-way balancing account established in Phase 2, subject to periodic audits and refunds if the Commission so orders. In Phase 3, given the inherent uncertainties with planning across a 10-year period and certain costs being unforeseeable during Phase 2, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for implementation costs that do not meet the Phase 2 Conditions, and were recorded in the designated memorandum account up to a cap determined in the Phase 2 Decision. During Phase 3, the Commission will review any Phase 3 Applications for recovery of costs recorded in the memorandum account to determine whether such costs were just and reasonable, and incremental to any other costs approved by the Commission. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be found to be just and reasonable before being authorized for recovery. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever is last.

---

[4] Costs can only be recovered once the undergrounding project is considered used and useful.

Given the importance of the Phase 2 Conditions and the requirement that any costs recorded in the one-way balancing account must meet the Phase 2 Conditions, these *Guidelines* include a process to assess whether the recorded costs meet such conditions. Accordingly, periodic audits of the established balancing account will be performed to ensure the costs booked to the balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, benefit cost ratio ~~CBR~~(BCR) thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

Due to the SB 884 Program's expedited schedule, unless otherwise directed by the Commission, large electrical corporations shall respond to discovery requests within five (5) ~~business~~ days in either Phase of the SB 884 Program.

Phase 1 – Joint Application to resolve SPD-37 Issues

The three large electrical corporations eligible for participation in the SB 884 program (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric) are directed to file a joint application, hereafter the Phase 1 Application, within 60 days of the issuance of Resolution SPD-37 requesting approval of a proposal for addressing each of these three issues:

1. BCR Calculation
2. Audit Methodology
3. Cost Recovery Conditions

Specific guidance for the content of each proposal to be included in the Phase 1 Application follows.

BCR Calculation

The large electrical corporations' proposal for the BCR calculation shall detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications. The large electrical corporations' proposal shall be designed to promote comparability, transparency, and traceability in BCR calculations across large electrical corporations, while remaining adaptable to future improvements in data availability and analytical approaches. Any proposed methodology shall apply to the project level, and may allow for scalability to the portfolio level. It shall complement the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the BCR for the purposes of EUPs and provide more information on the calculation's key components. These key components of at least one proposed methodology shall, at a minimum, include:

- **Total Capital Cost**, defined as capital expenditures tied to project implementation. The relationship between Total Capital Costs and other categories, such as Operating and Maintenance (O&M)

Costs, O&M Savings, or Net Salvage values,[5] should be addressed.

- **Risk Scaling,** which should address whether unscaled (i.e., risk-neutral) risk values should be used in the BCR calculations.
- **Total Mitigation Benefit,** which may include:

  a. Risk Reduction, including Wildfire Ignition Risk and Outage Program Risk.

  b. Other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).

Different types of mitigation benefits should be clearly identified and distinguished to facilitate transparency and avoid double-counting.

- O&M Costs associated with operating and maintaining the project.
- O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline.[6]
- **BCR Year Zero**, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits. This BCR Year Zero definition shall be included in the large electrical corporations' BCR methodology proposal.
- **Interruption Cost Estimate (ICE)[7] Calculator Granularity**, the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability should be addressed.

Backcasting, a method for recalculating BCRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison should be proposed. The large electrical corporations shall include guidance on backcasting in any BCR methodology proposal.

Audit Methodology

The Phase 1 Application shall include a detailed description of the proposed methodology that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:

a. Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);

---

[5] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.

[6] No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU)implementation. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives.

[7] https://icecalculator.com/, see also D.22-12-027 OP 2b.

b. Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);

c. Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);

d. Determining that the average recorded BCR for all projects completed in any given two-year period equals or exceeds the approved threshold BCR value. (Condition #4); and

For the secondary objectives, this method must include an approach for:

e. Verifying that a project is used and useful.

f. Verifying the incrementality showing found in Application Requirement No. 2.

Cost Recovery Conditions

The Phase 1 Application shall include a proposal for any additional portfolio or project-level conditions necessary to ensure that costs booked to balancing accounts are just and reasonable. At a minimum, large electrical corporations shall consider the following types of quantitative conditions: conditions that address how an undergrounding project compares to alternative mitigations; conditions that address how the actual BCR of a project compares to its forecasted BCR; conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost. For each quantitative condition, large electrical corporations should propose a numerical threshold that can be used to evaluate whether the condition has been met. Parties to the Phase 1 Application may respond to each of the large electrical corporations' proposals and make counter proposals within 15 calendar days of the large electrical corporations' filing(s).

Required Data

In order to consider the practical implications of the proposed BCR methodologies, audit methodologies, and cost recovery conditions, upon filing their EUP with Energy Safety, large electrical corporations shall file in the Phase 1 Application proceeding the most recent versions of all available data identified in the *SB 884 Project List Data Requirements Guidelines* using the *SB 884 Project List Data Template*

Phase 1 Application Submission Requirements:

The Phase 1 Application submitted to the Commission shall meet all the following requirements.

Submission Deadline:

The Phase 1 Application shall be jointly filed by the three large electrical corporations eligible for participation in the SB 884 Program within 60 days of the issuance of Resolution SPD-37.

Phase 1 Application Type:

The Phase 1 Application shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[8] Each section

[8] Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 3, Rule 3.2.

of the Phase 1 Application shall indicate the person(s) who sponsors the section and would serve as a witness if evidentiary hearings are required.

Phase 1 Application Submission:

The Phase 1 Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service lists for each large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[9] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporations, that will cause the Phase 1 Application to broadly reach interested parties.

Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit the Application.[10] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days of notice. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting these *Guidelines*, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month timeline for the Commission's review.

Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[11] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring

[9] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

[10] Public Utilities Code, Section 8388.5(e)(5).

[11] Pre-submission of the Application for completeness review shall be submitted to SB884@cpuc.ca.gov.

that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is not a substantive review or disposition of the Application and does not limit the Commission's or staff's ability to require the large electrical corporation to otherwise modify or resubmit the Application.

Phase 2 – Application Submission and Review:

These *Guidelines* recognize that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2). The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

Application Submission Requirements:

Applications submitted to the Commission seeking conditional approval of Plan costs shall meet all the following requirements.

Submission Deadline:

Applications for Commission review, and conditional approval or denial of the Plan's costs, as such conditional approval is described herein, must be submitted to the Commission within 60 days following Energy Safety's approval of the Plan.

Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting these *Guidelines*.[12] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent ~~general rate case (~~GRC~~)~~, the SB 884 notification list linked here,[13] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties. A copy of the ~~a~~Application should also be sent to each communications company that has equipment on poles where undergrounding is planned.

Application Requirements:

[12] Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 3, Rule 3.2.

[13] The SB 884 notification list is periodically updated and uploaded to CPUC SB 884 webpage: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

For the purposes of these *Guidelines*, all program and project costs reported in the Application shall include the standard project costs including, but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting. In addition, all ratepayer impacts shall be shown by all ratepayer classifications (e.g., residential, agricultural, commercial, etc.) to the extent such information is available.

All cost and ~~Cost-Benefit Ratio (CBR~~BCR~~)~~ data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following are required contents of all Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[14]) and cost forecasts[15] in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:
    a) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts approved in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.
    b) Where undergrounding targets and cost forecasts in the Application overlap with undergrounding targets and cost forecasts still under consideration in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.
    c) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.
3) The Application shall include the large electrical corporation's best estimate, including all underlying assumptions, of the proposed annual revenue requirements and proposed ratepayer impacts for each year that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.
4) The Application shall include a Results of Operation (RO) Model for that portion of its revenue requirement that relates to the undergrounding cost recovery it seeks, with Energy Division

[14] As used in this context, "conversion rate" means the ratio of underground mileage required to replace the equivalent overhead lines. Given prior evaluation of undergrounding requests in other Commission proceedings, it is known that a mile of undergrounding corresponds to replacement of less than one mile of overhead assets.

[15] For clarity, the term cost forecasts is used in place of the term cost targets that are discussed in PUC 8838.5 (3)(1).

oversight and a non-disclosure agreement in place,[16] that demonstrates how the large electrical corporation calculated the revenue requirement provided.[17]

5) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management), collectively "savings," and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[18]
    a) The Application shall distinguish between forecast costs already approved by the Commission for recovery and forecast costs that have not yet been the subject of a request for recovery.
    b) For forecast costs already approved by the Commission for recovery, the Application shall identify any accounts used to track such costs; the amounts in each such account; and the Commission decision(s) authorizing recovery.
    c) The application shall explain the proposed disposition of all identified savings and explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers.
6) The Application shall include cost forecasts for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.
    a) Cost forecasts shall be provided for each projected year in the 10-year Plan.
    b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.
    c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.
7) The Application shall include an explanation of how the cost forecasts are expected to decline over time due to cost efficiencies and economies of scale.
8) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or

---

[16] The non-disclosure agreement shall ensure that the large electrical corporation personnel in charge of the RO modeling will not disclose changes to the RO Model requested by the Commission to the personnel working on the Phase 2 Application and related matters.

[17] See also D.00-07-050 at 11-12 and D.20-01-002 at 65-67.

[18] For examples of cost ~~benefits~~ savings that may be appropriate to include, refer to the Lawrence Berkeley National Laboratory white paper. Peter H. Larsen, "A method to estimate the costs and benefits of undergrounding electricity transmission and distribution lines" in Energy Economics Vol. 60, 2016 pp. 47-61. Please note that this methodology is referenced for illustrative purposes only. Different methodologies and/or cost categories may be appropriate to include.

economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

9) The Application shall present the forecasted average ~~Cost-Benefit Ratio (CBR)~~ BCR across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. ~~Cost and Benefits~~BCR must be calculated as ~~defined in Commission Decision (D.)22-12-027[19] or its successor~~directed in the Phase 1 Decision. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[20] The costs and benefits of any projects that will include secondary lines and service drops must also be included.

10) The Application shall include the forecasted ~~CBR~~BCRs across all projects, by year and for the total Application period, for each alternative wildfire mitigation hardening method considered, in place of undergrounding, including forecasted ~~CBR~~BCRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.
    a) The large electrical corporation shall use reasonable and comparable assumptions in its calculations of forecasted ~~CBR~~BCRs for both undergrounding and each alternative wildfire mitigation method considered, including combinations thereof.

11) The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.
    a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.
    b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.

12) For each project included in the Application, the large electrical corporation shall provide, at a minimum, all data listed in the *SB 884 Project List Data Requirements Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and searchable pdf file[21] to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *SB 884 Project List Data Requirements Guidelines* at the time of its Application submission.

13) The Application shall include the latest data associated with the list of all projects (*SB 884 Project List Data Requirements Guidelines*) as required by Screen 2 of the *Energy Safety Guidelines*. The large electrical corporation shall provide a forecasted scope of all projects in the approved 10-year EUP and

---

~~[19] CBR~~~~BCR~~ ~~is calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3. The BCR calculation methodology may be revised, for the purposes of the SB 884 Program, as a result of the Phase 1 Application process.~~

[20] Based on information provided in PG&E's wildfire mitigation plans and current general rate case, the overhead to underground conversion rate is approximately 1.25. This means that it would require PG&E approximately 125 miles of underground circuit miles to convert 100 miles of overhead infrastructure to underground. As such, calculated benefits would relate to the 100 miles of overhead infrastructure undergrounded and not the 125 miles of undergrounding required to do so. The underground conversion rate will vary per large electrical corporation.

[21] See Rules of Practice and Procedure: California Code of Regulations Title 20, Division 1, Chapter 1. Article 1, Rule 1.3(b) for complete submission requirements of pdf files.

included in the Undergrounding Projects List, as an output from Screen 2 of the *Energy Safety Guidelines*.

14) The Application shall only include undergrounding projects that have a forecasted ~~CBR~~BCR greater than or equal to 1.

~~15) The Application shall only include undergrounding projects that have met one or more of the large electrical corporation's three Project-Level Thresholds.[22]~~

~~16)~~15) The Application shall include a detailed explanation of the necessity for any spans that extend beyond the HFTD boundary for any project included in the Application.
   a) The Application shall only include undergrounding projects that have been designated as an In-Area circuit segment as required by Screen 1 in the *Energy Safety Guidelines*.[23]

~~17)~~16) The Application shall include:
   a) The same Key Decision-Making Metrics (KDMMs) data for Commission review as was provided in the EUP approved by Energy Safety.
   b) The KDMMs included in any six-month progress report submitted to Energy Safety during the nine-month period that the large electrical corporation's EUP is under review by Energy Safety.

~~18)~~17) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format.
   a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
   b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
   c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.

~~19)~~18) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
   a) The source of third-party funding;
   b) The date when third-party funds were requested;
   c) The amount of funding requested;
   d) The status of the request, including funding already received;
   e) Next steps, including timelines for processing of the funding request; and
   f) The amount of funding granted/authorized (if any).

~~20)~~19) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.

~~21)~~20) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[24]

~~[22] *Energy Safety Guidelines* at 42. The large electrical corporation indicates to Energy Safety whether a circuit segment falls into one of the mitigation eligibility categories in Table C.8 under the "risk_category" field.~~

[23] *Energy Safety Guidelines* at 12. The large electrical corporation indicates to Energy Safety whether a circuit segment is designated as "In-Area" in Table C.6 under the "is_in_area" field.

[24] Resolution E-5254 adopted procedural mechanisms for review and approval of electric and gas investor-owned utility cost recovery requests related to various federal funding and grant programs. Resolution E-5254 is available on the Commission's website at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

~~22)~~21)The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.

~~23)~~22)The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:

a) The ownership and use of existing utility poles where undergrounding projects are planned;

b) How the large electrical corporation will address the affected shared poles, including who will own and maintain the poles if the responsible communication provider opts not to concurrently underground their infrastructure;

c) The full array of currently offered or discussed proposals for how to add conduit for such communication companies in the large electrical corporation's trenches, including, wherever possible, the proposed unit costs associated with such offerings or proposals.

~~24)~~23)The Application shall include a plan of how and when the large electrical corporation will remove poles from its rate base whose ownership is transferred to a communications company.

~~25)~~24)The Application shall include workforce development cost forecasts for each year of the Plan.

~~26) The Application shall include a detailed description of the method that establishes how the auditor will validate whether the large electrical corporation has satisfied the primary and secondary objectives of the audit. For the primary objectives, this method must include an approach for:~~

~~a) Verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP (Condition #1);~~

~~b) Verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained (Condition #2);~~

~~c) Determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap (Condition #3);~~

~~d) Determining that the average recorded CBRBCR for all projects completed in any given two-year period equals or exceeds the approved threshold CBRBCR value. (Condition #4);~~

~~e) Determining whether the forecasted CBRBCR of an undergrounding project alternative mitigation exceeds a certain threshold value above the forecasted CBRBCR of an alternative mitigationundergrounding project , which is subject to rebuttal during a Phase 2 Application proceeding.(Condition #5);~~

~~f) Verifying that a project did not exceed the approved CBRBCR percentage difference threshold (Condition #6);~~

~~g) Verifying that a project did not exceed the approved unit cost percentage difference threshold (Condition #7); and~~

~~h) Verifying that the undergrounding project meets or exceeds the applicable Project-Level Standard in the large electrical corporation's EUP approved by Energy Safety (Condition #8).~~

~~For the secondary objectives, this method must include an approach for:~~

~~i) Verifying that a project is used and useful.~~

~~j) Verifying the incrementality showing found in Application Requirement No. 2.~~

~~k) Validating the methodology used to calculate a CBRBCR for a given project, as found in the *CBRBCR Calculation Guidelines* in Appendix 1 of these *Guidelines*.~~

~~27)~~25)The Application shall include a copy of the Plan approved by Energy Safety.

Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered.

Conditions for Approval of Plan Costs:

Public Utilities Code, Section 8388.5(e)(1) specifies that an Application may request "conditional approval of the plan's costs…" To protect ratepayers from unexpected and inefficient cost overruns, the Commission establishes the following conditions for any costs booked to the one-way balancing account established in Phase 2:

1) Total annual costs must not exceed a cap based on the approved cost cap for that specific year.[25]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed the approved average unit cost cap for the current year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
4) The average recorded ~~CBR~~BCR[26] for all projects completed in any given two-year period (the current year, and the prior year) must equal or exceed the approved threshold ~~CBR~~BCR value[27] for the current year.
5) ~~The forecasted CBRBCR of the undergrounding project must exceed the forecasted CBRBCR of all alternative mitigations considered for that project by a certain threshold value, which is to be determined in the Phase 2 Decision. This condition is a rebuttable presumption that may be rebutted in the Phase 2 Application proceeding.~~
6) ~~In all cases, when an undergrounding project becomes used and useful, if the value of its recorded CBRBCR, as reported in the applicable six-month progress report, is less than the value of its forecasted CBRBCR at the time of the Phase 2 Application submission, then the percentage difference between the two CBRBCR values must not exceed the specified threshold value determined in the Phase 2 Decision.~~
7) ~~In all cases, when an undergrounding project becomes used and useful, if the value of its recorded unit cost, as reported in the applicable six-month progress report, is greater than the value of its forecasted unit cost at the time of the Phase 2 Application submission, then the percentage difference between the two unit cost values must not exceed the specified threshold value determined in the Phase 2 Decision.~~

[25] Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of these *Guidelines*.

[26] The "recorded ~~CBR~~BCR" is the ~~CBR~~BCR calculated using recorded cost values, as opposed to cost forecasts.

[27] The "threshold ~~CBR~~BCR value" will establish the minimum ~~CBR~~BCR that must be achieved for cost recovery.

~~8) The undergrounding project must meet or exceed the applicable Project-Level Standard(s) in the large electrical corporation's EUP approved by Energy Safety.[28]~~

~~9)~~ Any further reasonable conditions adopted by a future Commission decision.~~Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.~~

Memorandum Account Cap:

The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall be capped as a percentage of the total sum of the 10 years of cost caps placed on the one-way balancing account. The percentage value of the memorandum account cost cap will be established in the Phase 2 Decision.

Phase 3 – Review of Memorandum Account Recorded Costs for Rate Recovery:

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, the large electrical corporation shall also report on its progress, and begin booking costs to the one-way balancing account established in Phase 2, which shall remain subject to periodic audits, and refund if the Commission so orders. In Phase 3, the large electrical corporation may also request rate recovery (via a separate Phase 3 Application) for any implementation costs that do not meet the Phase 2 Conditions and were recorded in the designated memorandum account. The large electrical corporation may only seek recovery for costs recorded in the memorandum account by filing a Phase 3 Application. The total cumulative costs recovered via the memorandum account throughout the duration of an EUP shall not exceed the cap established for such accounts in the Phase 2 Decision. The purpose of any Phase 3 Application will be to determine whether the costs recorded in the memorandum account meet the conditions set forth in the "Conditions for Approval of Recorded Costs in Memorandum Account" section below. When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. No more than one Phase 3 Application may be filed each year.

~~[28] *Energy Safety Guidelines* at 17 and 43. The large electrical corporation indicates to Energy Safety whether an undergrounding project has met the Project-Level Standard(s) in Table C.12 of the *Energy Safety Guidelines* under the "fulfills_project_level_standard" field. The "applicable Project-Level Standard(s)" can be verified by how the utility completes the "risk_category" field in Table C.8 of the *Energy Safety Guidelines*. If the undergrounding project does not meet the applicable Project-Level Standard(s), the *Energy Safety Guidelines* still permit a large electrical corporation to record a justification for this project in Table C.12 under the "additional_justification" field, which can be reviewed as part of a Phase 3 Application to determine the just and reasonableness of the costs associated with a project that does not meet this condition.~~

The elements of recorded costs must be consistent with the elements included in the costs presented in the Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all six-month progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following program data presented in Table 1 for the requested recovery period.[29] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet. Additional data requirements for a Phase 3 Application may be included in the Phase 2 Decision.

Table 1: Conditionally Approved Target and Actual Recorded Cost Data

Conditionally Approved Targets for the Recovery Period	Actual Recorded Costs in the Recovery Period
Program Cost	Program Cost
Program ~~CBR~~BCR	Program ~~CBR~~BCR
Program Unit Cost	Program Unit Cost
	Project Data for the Recorded Projects

Conditions for Approval of Recorded Costs in Memorandum Account:

To further protect ratepayers from unexpected and inefficient cost overruns:

1) The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.
2) When making these determinations the conditions set forth in the Resolution adopting these *Guidelines*, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.
3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless and until the large electrical corporation has shown that it has applied all third-party funding previously received to reduce its relevant balancing account cost cap.
4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be authorized for recovery unless such costs are consistent with the approved Plan.

Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Accordingly, without affecting the required progress report elements specified by Energy

[29] Recovery period means the period under consideration in the most recent Phase 3 Application filing.

Safety, these *Guidelines* require that the six-month progress reports shall include, but should not be limited to, the following:

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded ~~CBR~~BCR for completed projects in any given two-year period;
4) Average recorded unit cost per mile of undergrounding for completed projects in any given two-year period;
5) Miles of overhead replaced by undergrounding by circuit segment;
6) Miles of undergrounding completed by circuit segment;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format);
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements 19-21; and
9) Total and average avoided costs and workpapers showing calculation of avoided costs.
10) An updated dataset that follows the requirements of the *SB 884 Project List Data Requirements Guidelines*.

At a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the *SB 884 Project List Data Requirements Guidelines* in Appendix 2, as well as any other reporting requirements in the *Energy Safety Guidelines*, the Phase 2 Decision(s), and the Phase 2 Application Requirements listed above. Large electrical corporations shall file and serve the six-month progress reports in the applicable Phase 2 Application docket. Parties may review, file, and serve opening comments on the progress report in the Phase 2 Application docket no later than 42 days (or such period specified in the Phase 2 Decision) after the progress report is filed and served by the large electrical corporation. Reply comments on the progress report may be filed and served in the Phase 2 Application docket no later than seven (7) days (or such period specified in the Phase 2 Decision) after the due date for opening comments.

Audit of the One-Way Balancing Account:

An audit of the one-way balancing account shall occur annually (hereafter, EUP Audit). The EUP Audit shall begin no later than 60 days (or such period specified in the Phase 2 Decision) after the due date for reply comments on the second six-month progress report in a given 12-month period. Each EUP Audit shall review EUP projects that become used and useful during the 12-month period covered by the audit. Each EUP Audit may also review recorded costs of projects or portions of projects that are not used and useful and may recommend refunds.

The primary objective of an EUP Audit is to determine whether the costs recorded in the large electrical corporation's balancing account have met all four ~~nine~~[30] Phase 2 Conditions. The audit shall also verify whether the recorded costs have met the following secondary objectives set forth in SPD-37:

1) Verify that projects are "used and useful;" and
2) Determine whether the recorded costs are incremental – and do not duplicate costs allowed

[30] The EUP Audit scope will also include any Phase 2 Conditions adopted in a future ~~the Phase 2 Decision~~a Commission Decision beyond those ~~e nine~~ listed herein.

through another decision, mechanism or received from a third party~~; and~~.

~~3) Validate that the methodology used to calculate a CBRBCR, and the CBRBCR results for a given project comply with the *CBR*BCR Calculation Guidelinesmethodology established in the Phase 1 Application Decision.(See Appendix 1).~~

A Phase ~~2~~ 1 Decision may also add primary and/or secondary objectives for the EUP Audit~~s specific to that EUP~~.

~~In its Phase 2 Application, as required by Application Requirement #26, a large electrical corporation shall propose the methodology for the auditor to determine whether the costs of undergrounding projects recovered via the one-way balancing account meet the primary and secondary objectives.~~

As for the specific method the auditor will use to verify whether the costs of underground projects recovered via the one-way balancing account met the primary and secondary objectives, such methodology will be determined via the Phase 1 Application process~~, as discussed in Section 3.5.2 below.the Phase 1~~.

~~The Phase 2 Decision will include the Commission's determination on the appropriate methodology to be used by the auditor to determine whether the primary and secondary objectives are met. In addition, any data that should be reviewed by the auditor, beyond what is submitted to the Commission in six-month progress reports, will be determined in the Phase 2 Decision. The auditor may also request information and conduct interviews with large electrical corporation personnel, including custodians of records, to gather information for the audit.~~

The EUP Audit will result in an audit report that will be filed and served to the Phase 2 Application docket within five (5) days (or such period specified in ~~the Phase 2~~a future Commission Decision) of its completion and approval. The audit report shall be completed within six months (or such period specified in the Phase 2 Decision) after it is initiated.[31] Parties may file and serve opening comments on the audit report in the Phase 2 Application docket no later than ~~20~~ 42 days (or such period specified in the Phase 2 Decision) after the audit report is filed and served by the large electrical corporation. Reply comments on the audit report may be filed and served in the Phase 2 Application docket no later than ~~five~~ seven days (or such period specified in ~~the Phase 2~~a future Commission Decision) after the due date for opening comments. ~~If a Party believes a refund is necessary based on the audit report, they may file a petition for modification requesting to reopen the Phase 2 Application proceeding and set forth the amount of the refund and the reasons for it in the petition.~~ The Commission may ~~also~~ determine the appropriateness of reopening the Phase 2 Application proceeding based on its ~~own~~ review as described below.

Following its review of the audit report, six-month progress reports, associated comments, and any petitions received, the Commission may reopen the Phase 2 Application proceeding to consider the need for refunds. If the Commission reopens the Phase 2 Application proceeding, for projects that do not meet the primary objectives and/or one or more of the secondary objectives, the Commission may direct the large electrical corporation to refund related project costs to ratepayers in a subsequent decision. If the Commission directs a large electrical corporation to issue a refund, the large electrical corporation shall not seek to recover such costs through any other means.

[31] Staff are authorized to extend the deadline for the audit report should a determination be made that such an extension is necessary to adequately complete the audit.

The large electrical corporation shall not have input into the direction, focus, or outcome of the EUP Audit that goes beyond the input afforded to other Parties to the Commission's SB 884 proceeding or process. The large electrical corporation shall provide access to all information requested by the auditor and SPD to carry out the audit within five days (or such period specified in ~~the Phase 2~~a future Commission Decision) of each data request. The large electrical corporation shall also make personnel available for interviews on five days' notice (or such period specified in ~~the Phase 2~~a future Commission Decision) if the auditor seeks substantive information and a custodian of records for questions about the location and content of requested information.

Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff understand that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[32] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December 1.[33] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[34] The large electrical corporation shall have 180 days to correct and eliminate any deficiency specified in the independent monitor's report.[35] Energy Safety shall consider the independent monitor's compliance report and whether the large electrical corporation cured the deficiencies identified therein when making its determination on whether to recommend penalties to the Commission.[36]

Penalties:

Pursuant to Public Utilities Code, Section 8388.5(i)(2), the Commission may assess penalties on a large electrical corporation that fails to substantially comply with a Commission decision approving its Plan.

[32] Public Utilities Code, Section 8388.5(g)(1).

[33] Public Utilities Code, Section 8388.5(g)(3).

[34] Public Utilities Code, Section 8388.5(g)(1).

[35] Public Utilities Code, Section 8388.5(g)(2).

[36] Public Utilities Code, Section 8388.5(i)(1).

~~Appendix 1: Benefit-Cost Benefit Ratio Calculation Guidelines~~

~~Benefit-Cost Benefit Ratio (CBRBCR) Calculation Guidelines~~

~~SAFETY POLICY DIVISION~~

~~August 15, 2025~~

~~Contents~~

~~Executive summary~~

~~The *Benefit-Cost Benefit Ratio (CBRBCR) Calculation Guidelines* establishes a standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in Senate Bill (SB) 884 applications. This appendix to the *CPUC Guidelines* is designed to promote comparability, transparency, and traceability in CBRBCR calculations while remaining adaptable to future improvements in data availability and analytical approaches. It complements the *SB 884 Project List Data Requirements Guidelines*[1] by outlining how to calculate the CBRBCR and providing more information on its key components. These key components include:~~

- ~~**Total Capital Costs**, defined as capital expenditures tied to Project implementation, excluding ineligible categories such as Net Operating and Maintenance (O&M) CostsBenefits[2] or Net Salvage values.[3]~~

- ~~**Risk Scaling,** which is limited to using unscaled (i.e., risk-neutral) risk values in the CBRBCR calculations.~~

- ~~**Total Mitigation Benefit,** that may include:~~

  ~~a. Risk Reduction, which is limited to Wildfire Ignition Risk[4] and Outage Program Risk.[5] Large electrical corporations must exclude other enterprise risks such as Public Contact with Energized Electrical Equipment (PCEEE) and Distribution Overhead Asset Failure (DOVHD).~~

  ~~b. Net O&M CostsBenefits, calculated as the difference in O&M Cost Savings and New O&M Costs between the proposed Project and the No-Build Baseline.[6]~~

- ~~**CBRBCR Year Zero**, defined as the year a Project becomes "Used and Useful," which serves as the reference year for discounting both Total Mitigation Benefit and Capital Costs.~~

~~[1] The *SB 884 Project List Data Requirements Guidelines* were published on July 24, 2025, and are available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-requirements-guidelines.pdf.~~

~~[2] Calculated as "O&M Cost Savings" – "New O&M Costs."~~

~~[3] Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.~~

~~[4] *Energy Safety Guidelines* at Appendix A, A-3.~~

~~[5] *Energy Safety Guidelines* at Appendix A, A-4.~~

~~[6] No-Build Baseline represents a well-defined baseline scenario or what happens if no Project or RRU is implemented. The Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives. For example, The No-Build Baseline might be an overhead line that is not hardened, while the Build Baseline might be a proposed undergrounding mitigation. This concept is particularly useful when assessing incremental benefits and costs between competing build options, ensuring that decisions are grounded in a consistent and traceable analytical framework. No-Build Baseline corresponds to the "Baseline", as defined in the *Energy Safety Guidelines* at A-1.~~

- ~~**Interruption Cost Estimate (ICE)[7] Calculator Granularity**, the level of granularity (Customer Class separated by High Fire-Threat District (HFTD) and Non-HFTD regions) that large electrical corporations must use to disaggregate the monetized value of electric reliability.~~
- ~~**Backcasting**, a method for recalculating CBRBCRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs to ensure an "apples-to-apples" comparison.~~
- ~~**CBRBCR Percentage Difference**, quantifies the percentage difference between the original forecasted CBRBCR as reported in the Phase 2 Application (or the backcasted CBRBCR of the original forecast, recalculated using revised inputs and current RRU structures) and the CBRBCR reported in subsequent six-month progress reports.~~

~~Notes on Terminology:~~

- ~~"Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety Guidelines*) published by Office of Energy Infrastructure Safety (Energy Safety) on February 20, 2025.[8]~~
- ~~The terms "RRU" and "Project" are used in this document to refer to the units on which the CBRBCR is calculated[9]~~

~~1. Introduction to CBRBCR Calculation~~

~~The CBRBCR is a fundamental metric for evaluating the cost-efficiency of undergrounding Projects and alternative mitigations proposed under SB 884. It measures the trade-off between the anticipated benefits of Wildfire Ignition and Outage Program Risk Reduction and the associated implementation Costs of mitigation efforts. In addition to assessing individual Projects, the CBRBCR enables a fair and consistent comparison between undergrounding and other Wildfire mitigation strategies, supporting informed decision-making across a range of options. This document outlines the primary components necessary for calculating the CBRBCR, including CBRBCR Year Zero, ICE calculator granularity, Risk Reduction, and Capital Costs.~~

~~These guidelines: offer general direction and establish a consistent framework for CBRBCR calculations; are not intended to address every technical detail or potential analytical scenarios; and, complements and are intended for use in tandem with the *SB 884 Project List Data Requirements Guidelines* that define the structure, format, and terminology for SB 884 data submissions by providing the methodology for calculating the CBRBCR and its key components. While these documents aim to provide guidance for consistent and repeatable CBRBCR calculations, SPD Staff anticipate that updates will be made over time as data collection improves and additional requirements emerge. The Commission authorized SPD to make future updates and changes to the *SB 884 Project List Data Requirements Guidelines* after hosting at least one technical working group~~

~~[7] https://icecalculator.com/, see also D.22-12-027 OP 2b.~~

~~[8] *Energy Safety Guidelines* at A-4.~~

~~[9] For definitions of RRU and Project, please see *SB 884 Project List Data Requirements Guidelines*, page 4 and *Energy Safety Guideline* A-5.~~

~~(TWG) meeting about said updates and changes without the need for a Commission Decision or Staff Resolution.[10]~~

~~2. Key Components of the CBRBCR Calculation~~

~~2.1 CBRBCR Year Zero~~

~~CBRBCR calculations shall use the year in which the Project is expected to become "Used and Useful" as the designated CBRBCR Year Zero. CBRBCR Year Zero is the reference year to which Capital Costs and Risk Reduction and Other Benefits of CBRBCR calculations are discounted, ensuring that the CBRBCR for any Project is calculated at a consistent point in time. CBRBCR Year Zero is also the point that Risk Reduction and Other Benefits begin to be realized.~~

~~To calculate CBRBCR, Capital Costs for a Project shall be discounted (i.e., inflated) to CBRBCR Year Zero. By contrast, Risk Reduction and Other Benefits of the Project are assumed to begin accruing starting in CBRBCR Year Zero of the project and shall be discounted back to CBRBCR Year Zero. Figure 1 illustrates CBRBCR Year Zero and discounting of Capital Costs and Risk Reduction. The black "X" represents CBRBCR Year Zero. The orange bars indicate the years in which Project Costs are incurred (pre-CBRBCR Year Zero), and the orange arrows represent how those Costs are discounted to the CBRBCR Year Zero. The green bars show the years that Risk Reduction and Other Benefits are realized (post-CBRBCR Year Zero), while the green arrows demonstrate how those benefits are discounted.~~

~~CBRBCR Year Zero is Project or RRU specific, so the CBRBCR Year Zero for one Project may differ from another. Though the CBRBCR for each Project may be anchored to a different point in time, the numerator (Present Value of Risk Reduction) of the Project's CBRBCR and the denominator (Present Value of Costs) of the Project's CBRBCR are discounted to that same year, as noted above (CBRBCR Year Zero of the Project). This ensures that, despite differing timelines for different Projects, the CBRBCR remains a consistent and comparable metric across Projects. In general, this method enables fair comparison between Projects initiated or completed in different years, or Projects with varying asset lifespans.~~

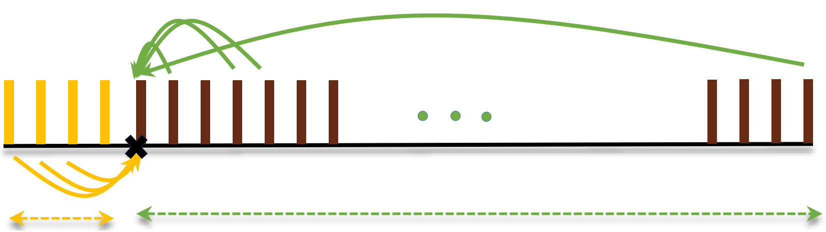

Figure 1: the timing of CBR Year Zero, incurred Project Costs, Risk Reduction, and Other Benefits

~~2.2 ICE Calculator 2.0 Granularity~~

~~Historically, large electrical corporations have applied a single value for dollars per customer-minute interrupted ($/CMI) to represent electric reliability valuation. However, this uniform approach fails to reflect~~

~~[10] SPD-37 at 37.~~

~~the heterogeneous distribution of customers and risk across service areas. A single value overlooks important differences in how outages affect residential versus non-residential customers and does not account for higher-risk regions such as HFTD areas to which the SB 884 program is limited. Large electrical corporations shall adopt a disaggregated approach to better capture the varying impacts of Projects or RRU across different customer classes and geographic risk tiers. Increased granularity, through segmentation by customer class and geographic tier, not only improves the precision of CBR~~BCR ~~calculations, but also ensures a more accurate and equitable evaluation of Project value.~~

~~For SB 884 Applications, the large electrical corporations shall calculate and use ICE Calculator granularity at the level of Customer Class (i.e., Residential vs Non-Residential) separated by HFTD and Non-HFTD regions. Large electrical corporations shall use the corresponding $/CMI values for each Customer Class in the CBR~~BCR ~~calculation of an undergrounding Project and alternative mitigations to ensure consistent and representative valuation of electric reliability.~~

~~2.3 Risk Scaling~~

~~To ensure consistency and comparability with the *Energy Safety Guidelines*, large electrical corporations shall calculate and present the CBR~~BCR ~~and all related components of the risk using unscaled (i.e., risk-neutral) risk values in the CBR~~BCR ~~calculations.~~[11]

~~2.4 Total Mitigation Benefit~~

~~Risk Reduction~~

~~Risk Reduction refers to the nominal, monetized value of risk that is reduced by implementing the proposed mitigation. For CBR~~BCR ~~calculations, only two risk events may be included in the CBR~~BCR~~'s Risk Reduction component: Wildfire Ignition Risk; and, Outage Program Risk, where Outage Programs exclude maintenance outages and other outages not related to reducing wildfire.~~

~~Large electrical corporations shall clearly document the methodology used to calculate and combine Wildfire Ignition Risk Reduction and Outage Program Risk Reduction in the workpapers required for CBR~~BCR ~~calculations.~~[12] ~~This includes, but is not limited to, detailing whether these risks are mutually exclusive or explaining how any potential overlap is addressed to avoid double-counting.~~

~~Other Benefits (Net O&M Costs~~Benefits~~)~~

~~Large electrical corporations may include Net O&M Costs~~ Benefits ~~as part of the Total Mitigation Benefit in the CBR~~BCR~~'s numerator, where Net O&M Costs~~ Benefits ~~is defined as:~~

~~Net O&M Costs~~ Benefits ~~= O&M Cost Savings – New O&M Costs (Eq. 1)~~

~~Where "O&M Cost Savings" are the difference between the O&M costs of the No-Build Baseline and the Build Baseline, and "New O&M Costs" represent the O&M costs that are unique to the Build Baseline. This~~

~~[11] *Energy Safety Guidelines* at 31.~~

~~[12] *CPUC Guidelines* at 7.~~

~~approach[13] allows the large electrical corporation to account for other contributing benefits of the Project or RRU beyond Risk Reduction, such as avoided or reduced maintenance needs relative to the status quo or No-Build Baseline while ensuring that the O&M costs relative to the Build Baseline are excluded as a benefit. The guidelines here clarify that such Other Benefits may only be accounted for in the numerator of a CBRBCR calculation.~~

~~The CBRBCR calculation shall be based only on the incremental difference between the proposed Project or alternative mitigation and the No-Build Baseline, both in terms of benefits risk reduction and net costs (Net O&M CostsBenefits). This comparative framework will assist in preventing double-counting and ensure analytical consistency. Net O&M Costs Benefits should be calculated for both the No-Build Baseline and the Build Baseline, while the difference between them may then be factored into the CBRBCR of the Project as Other Benefits.~~

~~Present Value of Risk Reduction and Other Benefits~~

~~Total Mitigation Benefit represents the Present Value of the Risk Reduction over the Project's lifespan - and potentially the Present Value of Net O&M Costs Benefits compared to No-Build Baseline. If the Risk Reduction in year "*t*" is "RR_t," then the discounted Risk Reduction in CBRBCR Year Zero is calculated as:~~

$$RR_u = RR_t \times \frac{1}{(1+r)^{t-u}} \quad \textit{(Eq. 2)}$$

~~Where "*t*" is greater and equal to CBRBCR Year Zero, "*u*" is CBRBCR Year Zero, and "*r*" is the discount rate (e.g., WACC[14]) used to discount future Risk Reduction to the CBRBCR Year Zero of the Project. The Present Value of Net O&M Costs Benefits can be calculated similarly.~~

~~To calculate the Total Mitigation Benefit, accrued annually over the life of the asset, the Present Value of Risk Reduction and potentially Net O&M Costs shall be added:~~

$$\textit{Total Mitigation Benefit} = \sum_{t=u}^{n=Asset\ life} \frac{RR_t}{(1+r)^{t-u}} + \textit{Present Value of Net O\&M Costs Benefits} \quad \textit{(Eq. 3)}$$

~~Where RR_t is the Risk Reduction in year "*t*," "*t*" is a year in which Risk Reduction occurs starting from the CBRBCR Year Zero of the Project, "*u*," "*r*" is the discount rate, "*n*" is the final year of the asset's useful life, "*u*" is the CBRBCR Year Zero.~~

~~Total Mitigation Benefit is used in CBRBCR calculations as the numerator.~~

~~Constraints~~

~~Included Risks~~

~~[13] See generally Department of Transportation, *Benefit Cost Analysis Guidelines for Discretionary Grant Programs*, published in May 2025, https://www.transportation.gov/sites/dot.gov/files/2025-05/Benefit%20Cost%20Analysis%20Guidance%202025%20Update%20II%20%28Final%29.pdf.~~

~~[14] Weighted average cost of capital.~~

~~For the purposes of CBRBCR calculations, only Wildfire Ignition Risk and Outage Program Risk may be included in the Risk Reduction component as defined in the *Energy Safety Guidelines*.[15] These two risk types may be combined in the CBRBCR calculation only if the large electrical corporation can demonstrate mutual exclusivity or if any potential overlap is explicitly identified and appropriately addressed to avoid double-counting.~~

~~Net Operations and Maintenance may be included in the Project CBRBCR's Total Mitigation Benefit.~~

~~Excluded Risks~~

~~Other enterprise risk categories, such as Public Contact with Intact Energized Electrical Equipment or Distribution Overhead Asset Failure, shall not be included in the CBRBCR calculation.~~

~~2.5 Capital Costs~~

~~When incorporating Project costs for a Project that will be built over several years, it is important to account for the time value of money. While Capital Costs refer to the summation of total nominal Capital Costs of Projects for the years the Project is being built, Present Value of Capital Costs is the summation of all discounted Capital Costs for each year to the CBRBCR Year Zero. Present Value of Capital Costs is used in CBRBCR calculation as the denominator.~~

~~If the nominal Capital Costs for a Project incurred in year "*t*," is~~ $Cost_t$ ~~and "*u*" is the Project's CBRBCR Year Zero, then:~~

$$Cost_u = Cost_t.(1+d)^{u-t} \quad \textit{(Eq. 4)}$$

~~Where~~ $Cost_u$ ~~is the Capital Costs for the Project in year t, discounted to the CBRBCR Year Zero of the Project, "*d*," is the discount rate, "*u*" is the CBRBCR Year Zero, and "*t*," is the year the cost incurred.~~

~~Present Value of all the Capital Costs for the Project can be calculated as:~~

$$PVCOST = \sum_{t=t0}^{u} Cost_t.(1+d)^{u-t} \quad \textit{(Eq. 5)}$$

~~Where~~ $Cost_t$ ~~represents the Capital Costs in year "*t*" (the year the costs were incurred,) "*d*" is the discount rate, "*u*" is the CBRBCR Year Zero, and~~ t_0 ~~is the year Project costs begin accruing.~~

~~The Present Value of Capital Costs incurred in year "*t*" can be discounted to the year Project costs begin accruing at "*t₀*" using the following equation:~~

$$Cost_t = Cost_{t_0}.(1+inf)^{t-t_0} \quad \textit{(Eq. 6)}$$

~~Where "*inf*" is the inflation rate.~~

~~In a WACC Discount Rate scenario[16] both the numerator (i.e., Total Mitigation Benefits) and the denominator (i.e., Capital Costs) of the CBRBCR are discounted using the same discount rate. Specifically,~~

~~[15] *Energy Safety Guidelines* at A-4.~~

~~[16] Phase 3 of Risk-Based Decision-Making Framework (RDF) (D.24-05-064) at 102-103.~~

the discount rates "*d*" and "*r*" used in Eq. 3 (for the numerator) and Eq. 5 (for the denominator) are equal. In contrast, under the Hybrid scenario different rates are applied, as discussed in the *SB 884 Project List Data Requirements Guidelines*[17]

Constraints

Included Costs

For the purposes of CBRBCR calculations, large electrical corporations may only include Capital Costs in the denominator of a CBRBCR calculation. Capital Costs are capital expenditures (Labor, Materials, Permits, and Others), attributable to the implementation of an SB 884 undergrounding and its alternative mitigations Projects, as outlined in the *SB 884 Project List Data Requirements Guidelines.*

Excluded Costs

Net O&M Costs Benefits (e.g., Cost Savings and added Costs) and Net Salvage values shall not be incorporated into the Capital Costs and Present Value of Capital Costs used in CBRBCR calculations.

3. Backcast

Backcasting uses updated inputs (e.g., new RRUs, new risk models, and changes to the specific portion of the circuit segment selected for mitigation) to recalculate CBRBCRs, pre-mitigated risk, post-mitigated risk or other data points submitted in Phase 2 Applications. The goal of a Backcast is to establish a bridge between prior inputs and new inputs to ensure an "apples-to-apples" comparison. With the adoption of the *Energy Safety Guidelines*, Energy Safety introduced the concept of the "Subproject."[18] As Projects are being further scoped, the *Energy Safety Guidelines* allow the large electrical corporation to establish Subprojects by dividing Projects into one or more units for operational reasons or to reflect that a portion of a circuit segment will be treated with a wildfire mitigation other than undergrounding.[19] These types of changes can occur after the Commission's Phase 2 Decision is adopted. Thus, the need to incorporate the concept of backcasting is essential to enable consistent comparison of a forecasted versus realized Project with full transparency and consistency. This comparison is particularly important when a large electrical corporation elects to use the Subproject Designation to provide an ability to track changes in the Project structure that occur over time, such as the transition from Project-level to RRU-level (or Subproject-level) tracking.

Large electrical corporations that elect to use the Subproject Designation to define RRUs after the Phase 2 Application must rely on Backcasting to enable consistent evaluation across reporting periods. Specifically, if an OEIS_Project_ID field value does not have a corresponding value in the RRU_ID field at the time of the Phase 2 Application submission, then the large electrical corporation must later backcast and report CBRBCR relevant metrics found in the *SB 884 Project List Data Requirements Guidelines,* including the following fields:

- Backcasted_Total_Mitigation_Benefit,

[17] *SB 884 Project List Data Requirements Guidelines*, Table 1 (page 18), and Table 5 (page 28)

[18] Energy Safety defines Subproject as "a delimited portion of work on a Confirmed Project." *Energy Safety Guidelines* at A-6.

[19] *Energy Safety Guidelines* at 14.

- ~~Backcasted_Present_Value_Costs, and~~
- ~~Backcasted_CostBenefit_BenefitCost_Ratio~~

~~These fields may be left blank at the time of Phase 2 Application filing and completed later in subsequent six-month progress reports once the RRU structure is finalized.~~

~~4. Calculation Methodology~~

~~4.1 CBRBCR Calculation~~

~~The CBRBCR is calculated using the CBRBCR Year Zero of the Project as the reference point. It is defined as the ratio of the Present Value of Risk Reduction and Other Benefits to the Present Value of Capital Costs, with all values discounted to CBRBCR Year Zero to ensure temporal consistency.~~

$$CBRBCR = \frac{Present\ Value\ of\ Risk\ Reduction\ and\ Other\ Benefits}{Present\ Value\ of\ Capital\ Costs} \quad (Eq.\ 7)$$

~~4.2 CBRBCR Percentage Difference~~

~~CBRBCR Percentage Difference refers to the percentage difference between the originally forecasted CBRBCR as reported in the Phase 2 Application (or the backcasted CBRBCR of the original forecast, recalculated using revised inputs and current RRU structures) and the CBRBCR reported in subsequent six-month progress reports. This percentage difference is particularly important for assessing the cost efficiency of Projects or RRUs during implementation, as more information becomes available over time.~~

~~CBRBCR_Percentage_Difference is calculated according to the following two scenarios:~~

a) ~~Assuming the Subproject designation is used by the large electrical corporation and Subproject data was not available in the Phase 2 Application:~~

$$(Eq.\ 8)$$

$$CBRBCR\_Percentage\_Ddiffernce = \frac{Backcasted\_CostBenefit\_BenefitCost\_Ratio - Updated\ CostBenefit\_BenefitCost\_Ratio\ in\ progress\ report}{Backcasted\_CostBenefit\_BenefitCost\_Ratio}$$

b) ~~Assuming the large electrical corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application:~~

$$(Eq.\ 9)$$

$$CBRBCR\_Percentage\_Ddifference = \frac{CostBenefit\_BenefitCost\_Ratio\ in\ Phase\ 2 - Updated\ CostBenefit\_BenefitCost\_Ratio\ in\ progress\ report}{CostBenefit\_BenefitCost\_Ratio\ in\ Phase\ 2\ Application}$$

~~4.3 Unit Cost Percentage Difference~~

~~The Unit Cost Percentage Difference refers to the percentage difference between forecasted Unit Costs submitted in the Phase 2 Application and updated Unit Costs in the subsequent progress reports. The Unit~~

~~Cost of a Project or RRU serves as a valuable metric for assessing costs of the project or the RRU and is calculated as such:~~

~~*(Eq. 10)*~~

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} - \text{Updated Unit Cost in progress report}}{\text{Forecasted Unit Cost in Phase 2 Application}}$$

~~"Unit Costs" refers to the field labeled as "Average_Unit_Cost_per_Mile" field in the *SB 884 Project List Data Requirements Guidelines*, Table 1.~~

~~5. Conclusion~~

~~This appendix is intended to guide large electrical corporations in calculating CBR~~BCR~~s consistently across SB-884 applications. It reflects input from the Technical Working Group and aligns with CPUC and *Energy Safety Guidelines* to ensure transparent and effective risk management.~~

~~6. Glossary~~

~~Table 1: Glossary of Terms Used in~~ Benefit-~~Cost-Benefit Ratio Calculation Guildelines~~

~~*Term*~~	~~*Definition*~~
~~u~~	~~The CBR~~BCR ~~Year Zero of a Project or when the Project is "Used and Useful".~~
~~RR_t~~	~~Annual Risk Reduction in year "t," where "t" is equal or greater than CBR~~BCR ~~Year Zero "u."~~
~~RR_u~~	~~Present Value of Risk Reduction in CBR~~BCR ~~Year Zero of the Project. It might include Ignition_Risk_Mitigation_Benefit and Outage_Program_Risk_Mitigation_Benefit.~~
~~r~~	~~The discount rate (e.g., WACC) used to discount future Risk Reduction to CBR~~BCR ~~Year Zero.~~
~~n~~	~~Asset life, i.e., the total number of years benefits are expected to accrue.~~
~~t_0~~	~~The base year when cost accumulation begins.~~
~~$Cost_t$~~	~~Capital Costs incurred in year "t."~~
~~$Cost_u$~~	~~The Capital Cost in year "t," discounted to CBR~~BCR ~~Year Zero "u"~~
~~No-Build Baseline~~	~~Represents a well-defined baseline scenario or the outcome if no Project or RRU is implemented.~~
~~Build Baseline~~	~~Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives. For example, The No-Build Baseline might be an overhead line that is not hardened, while the Build Baseline might be a proposed undergrounding mitigation.~~
~~Salvage value~~	~~Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.~~

~~Table 2: Glossary of Equations Used in Cost-Benefi Ratio Calculation Guildeline~~

~~*Equation Number*~~	~~*Description*~~
~~**(Eq. 1)**~~	~~Net O&M Costs~~Benefits
~~**(Eq. 2)**~~	~~Present Value of Risk Reduction in CBR~~BCR ~~Year Zero of the Project~~
~~**(Eq. 3)**~~	~~Total Mitigation Benefit~~
~~**(Eq. 4)**~~	~~Discounted Capital Costs to CBR~~BCR ~~Year Zero for a Project~~

~~(Eq. 5)~~	~~Present value of all Capital Costs for a Project, discounted to the CBRBCR Year Zero.~~
~~(Eq. 6)~~	~~The Present Value of Capital Costs discounted to the year the Project costs begin accruing~~
~~(Eq. 7)~~	~~Benefit-Cost-Benefit Ratio~~
~~(Eq. 8)~~	~~CBRBCR Percentage Difference assuming the large electrical corporation elects to use the Subproject, and Subproject data was not available in the Phase 2 Application~~
~~(Eq. 9)~~	~~CBRBCR Percentage Difference assuming the large electrical corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application~~
~~(Eq. 10)~~	~~Unit Cost Percentage Difference~~

Appendix ~~2~~1: SB 884 Project List Data Requirements Guidelines*

* The *SB 884 Project List Data Requirements Guidelines* were published by Safety Policy Division on July 24, 2025. Additional information, including the data template that large electrical corporations must use to file its Application and six-month progress reports can be found here: https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884. The *SB 884 Project List Data Requirements Guidelines* presented here supersede Appendix 1 of Resolution SPD-15.

California Public Utilities Commission

SB 884 Project List Data Requirements Guidelines

SAFETY POLICY DIVISION

July 24, 2025

Table of Contents

Background and Purpose:

Pursuant to Senate Bill (SB) 884 (McGuire; Stats. 2022, Ch. 819), the California Public Utilities Commission's (CPUC or Commission) data requirements for a large electrical corporation's Electrical Undergrounding Plan (EUP) intended to mitigate wildfire risk in the High Fire Threat District (HFTD), will be complex and require coordination with the Office of Energy Infrastructure Safety's (Energy Safety) Guidelines and data templates. Attached to Resolution SPD-15,[1] the Commission issued the *SB 884 Project List Data Requirements-Preliminary* to begin the discussion on how a utility should submit tabular and geospatial data in support of a Phase 2 Application related to its EUP.[2] Ordering Paragraph 3 of SPD-15 stated that:

> Following Energy Safety's publication of its SB 884 Guidelines, SPD is authorized to convene a Technical Working Group (TWG) to review and align the preliminary CPUC SB 884 Project List Data Requirements and Geographic Information System (GIS) data requirements with Energy Safety Guidelines, adding any data elements necessary for Commission conditional approval purposes.

Additionally, Ordering Paragraph 4 of SPD-15 stated that:

> SPD is authorized to develop and issue the SB 884 Project List Data Template within 30 days of the final TWG meeting.

As discussed below, the final TWG meeting was held on June 24, 2025. Thus, by issuing the *SB 884 Project List Data Requirements Guidelines* (henceforth referred to as the *CPUC SB 884 Data Guidelines*) to the SB 884 Notification List on July 24, 2025, SPD has completed the requirements of Ordering Paragraph 4 in SPD-15.

On February 20, 2025, Energy Safety published Guidelines that a large electrical corporation must follow to submit an EUP to that agency.[3] Energy Safety's Guidelines include extensive discussion of data requirements that require the Commission to review and determine the best way to align its own data requirements for a large electrical corporation's Phase 2 Application for the EUP. Following the TWGs discussed below, the *CPUC SB 884 Data Guidelines* represents an alignment between the data needs of the Commission to evaluate conditional approval of costs and the requirements found in the Energy Safety Guidelines as was required by Ordering Paragraph 3 in SPD-15.

On January 30, 2025, Safety Policy Division (SPD) presented a Risk Assessment and Mitigation Phase (RAMP) data template Guidelines and data template as part of a TWG in Phase 4 of the Risk-Based Decision-Making Framework (RDF) Proceeding (R.20-07-013).[4] On February 11, 2025, an Administrative

---

[1] Resolution SPD-15 is available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/final-resolution-spd15-adopting-the-commissions-guidelines-for-the-senate-bill-sb-884-program.pdf.

[2] SPD-15, Attachment 1, Appendix 1 at 15-18.

[3] Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines, February 20, 2025, https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58006&shareable=true.

[4] The RAMP is a process a utility complies with before initiating a GRC that requires energy-utility safety-risk threat assessments along with associated proposed mitigation plans and estimated costs and spending requests. The RDF proceeding examines how

Law Judge Ruling filed SPD's RAMP data template Guidelines and data template to the RDF Proceeding[5] SPD recognizes that it will be crucial that a data template for a Phase 2 Application also align with the data template needed in a RAMP and General Rate Case (GRC) Application. The structure of the *CPUC SB 884 Data Guidelines* is influenced by the discussion of Staff's data template Guidelines presented in the RDF Proceeding.

Commission Staff issued a "Staff Report on SB-884 Projects List Data Requirements Guideline" (or Staff Report) on May 20, 2025, which included a set of "Technical Working Group Questions". Commission Staff then hosted a series of three TWG meetings in June 2025. During the SPD TWG meeting #1, held on June 3, 2025, SPD Staff presented the Staff Report and addressed questions from stakeholders regarding potential updates to the SB 884 Project List Data Requirements. In a May 15, 2025, e-mail to the SB 884 Notification List, SPD offered the opportunity for any stakeholder to present their feedback and recommendations on the Staff Report. No stakeholders accepted this opportunity. However, Staff did receive a list of questions from Pacific Gas and Electric Company (PG&E), which it requested to be discussed during the SPD TWG meeting #2 on June 10, 2025. Additionally, the SPD TWG meeting #3 on June 24, 2025, included presentations from Lawerence Berkeley National Labs and PG&E on the Interruption Cost Estimate Calculator (ICE 2.0). Stakeholders held additional discussion related to the way ICE 2.0 was addressed within the Staff Report. Finally, Staff accepted stakeholder responses to the "Technical Working Group Questions" on June 24, 2025. The input received from stakeholders, along with the adoption of the Energy Safety Guidelines, informs the *CPUC SB 884 Data Guidelines* presented in this document.

The purpose of the *CPUC SB 884 Data Guidelines* is to provide clarity on the field name, field description, and field value constraints in the SB 884 Project List Data Template. Additionally, the *CPUC SB 884 Data Guidelines* is a revision of *SB 884 Project List Data Requirements-Preliminary* that was attached to SPD-15.

For each project included in the Plan and Application, the large electrical corporation shall provide, at a minimum, all data listed in the *CPUC SB 884 Data Guidelines* in tabular format. This information shall be provided as both a Microsoft Excel file and a searchable pdf file to supplement the Application. The large electrical corporation shall provide the latest version of the data required by the *CPUC SB 884 Data Guidelines* at the time of its Application submission. Additionally, at a minimum, the six-month progress reports filed by a large electrical corporation shall include an update of the data required in the *CPUC SB 884 Data Guidelines.*[6] The data values provided in each update of the data required in the *CPUC SB 884 Data Guidelines* should correspond to the date listed in each of the Reporting_Date fields found at the end of Tables 1-6.

to calculate risk mitigation levels for various safety measures in order to ensure utilities focus on the most cost-efficient risk reduction strategies in their safety work, including wildfire-related safety.

5 Administrative Law Judge's Ruling Entering Phase 4 Technical Working Group Materials and Related Staff Proposal into the Record and Setting Comment Schedule, February 11, 2025, https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=556602565.

6 Energy Safety Guidelines at 25-26.

Note on Terminology:

1. The term "Risk" in this document corresponds to "Overall Utility Risk" (unless otherwise noted) as defined in the Energy Safety Guidelines.[7]

[7] The 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025, page A-4.

Template and Tables Structure

Table 1: Data Set

This table collects the key elements and characteristics of a Risk Reporting Unit (RRU), including unique identifiers, mitigation plans, and associated risks.[8] Table 1 defines how risk-related data elements are structured and categorized for consistent reporting across various progress reports and geographic locations.

As stated in the introduction, it is necessary to align the SB 884 Project List Data Template with the RAMP Data Template discussed in the RDF Proceeding.[9] Here we present a definition of asset, RRU, and system to clarify that these concepts must be shared across RAMP and SB-884 Applications.

- <u>Asset</u>: A retirement unit as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) that exhibits risk.[10]
- <u>Risk Reporting Unit (RRU)</u>: A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk. The RRU must include common elements that must include, but are not limited to Consequence Attributes, Risk level, line-item costs, benefit-cost ratios (CBRs), work units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to, hierarchy,[11] scenario,[12] version,[13] risk event, tranche, and mitigation type.
- <u>System</u>: A regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit.

Unless otherwise specified, such as certain fields in Table 4, all data requirements related to assets, RRUs, and systems apply to but are not limited to, primary, secondary and service lines.

Additionally, to conform with the requirements of the CPUC's SB 884 Guidelines found in SPD-15 or any successor Commission order or decision, the RRU must be:

1. Traceable through all stages of a lifecycle, including but not limited to the project's scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.
2. Auditable in terms of timing, location, work units, costs, and Risk Reduction.
3. Forecastable to at least the 10th year of the EUP.

[8] For more information on the RRU, see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024.

[9] Any updates in the RDF Proceeding may result in an update in the SB-884 Data Template Guidelines.

[10] For the FERC USOA, see 18 CFR Part 101 https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

[11] Hierarchy refers to a utility's organizational hierarchy, such as an Electric Distribution Division or a Gas Distribution Division. as well as other ways of categorizing high risk assets and systems (i.e. HFTDs, circuits, regions, etc.).

[12] Scenario refers to forecasts, results, and projections.

[13] Version refers to a risk model version.

4. Able to aggregate up to the EUP.[14]

Utilities shall use these definitions and requirements to present RRU level data in their EUP. The level of granularity required is discussed below.

Tables 1 through 4 are anchored around the RRU_ID field, which references uniquely identifiable RRUs with unique identification numbers (i.e., IDs). A utility's RRU_ID naming schema must be simple and transparently understandable. A utility's RRU_ID naming schema must include the GRC Activity Code of the Undergrounding Project, which must also be listed in Table 1. A utility's RRU_ID naming schema must not result in the reuse of an RRU_ID.

Table 1 shall be submitted with the Phase 2 Application and all subsequent progress reports. In cases where RRU_IDs have not yet been created for certain projects, for the reasons outlined below, the table must be submitted using the corresponding OEIS_Project_ID.[15] Once more detailed and updated information becomes available, reporting in six-month progress reports shall transition to the RRU_IDs. The utility must continue reporting OEIS_Project_IDs to enable traceability and continuity across reports.

The fields OEIS_Project_ID and OEIS_Subproject_ID directly align to the Energy Safety Guidelines and enable coordination with the data templates submitted with the EUP to Energy Safety.[16] All requirements found in the Energy Safety Guidelines for OEIS_Project_ID and OEIS_Subproject_ID also apply to this data template.

If the utility submits a Phase 2 Application that does not use Subprojects, then the Commission requires that the granularity of the RRU be identical to that of the Project as defined in the Energy Safety Guidelines (see Figure 1). If the utility submits a Phase 2 Application that uses Subprojects the Commission requires that the granularity of the RRU be identical to that of the Subproject once detailed Subproject data is available, which means that each RRU_ID can only be tied to a single OEIS_Subproject_ID (Figure 2). Once an RRU_ID is created for a Subproject, all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

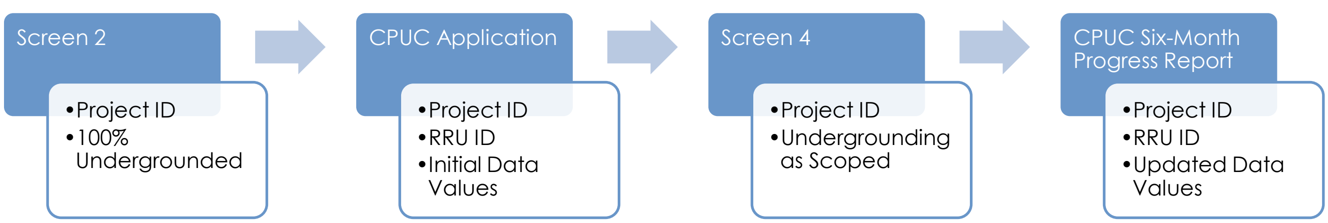

Figure 1: Process for creating an RRU_ID and Data Submissions for Phase 2 Application without Subprojects

[14] These three requirements have been adapted from the Staff Scoped Work Proposal to conform to the requirements of the SB-884 program.

[15] OEIS_Project_ID corresponds to project_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-24).

[16] OEIS_Subproject_ID corresponds to subproject_ID, as defined in the 10-Year Electrical Undergrounding Plan Guidelines published by Office of Energy Infrastructure Safety on February 20, 2025 (at C-36).

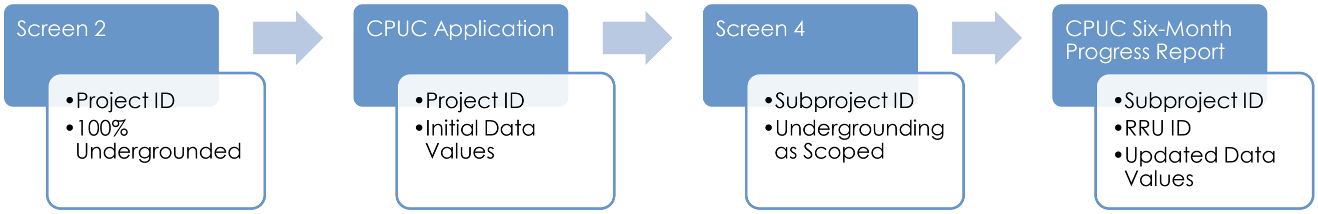

Figure 2: Process for creating an RRU_ID and Data Submissions for Phase 2 Application with Subprojects

If the utility elects to use Subprojects in its Phase 2 Application, then when the utility submits its Phase 2 Application to the Commission, it is possible that detailed Subproject level forecasts may not be available. In the case where the utility submits a Phase 2 Application that uses Subprojects and the Subproject level forecasts are not available, for the initial dataset submitted with the utility's Phase 2 Application, the utility may present forecasts at the Project Level, which should correspond with the Screen 2 data presented by the utility in Table C.11 of the Energy Safety Guidelines.[17] The forecasts presented at the Project Level in the initial dataset submitted with the Application will correspond to the "100% Undergrounded" concept defined in the Energy Safety Guidelines.[18] The RRU_ID field may be left blank at this point. Once detailed Subproject data is available, an RRU_ID must be created for each Subproject, and all data must be reported using the unique RRU_IDs, OEIS_Project_IDs and OEIS_Subproject_IDs.

When the utility submits its Phase 2 Application or six-month progress reports to the Commission, it is required that for any Project (i.e., OEIS_Project_ID) that passes Screen 4 of the Energy Safety Guidelines, the utility shall provide data values in the Commission's data template that should correspond with the Screen 4 data presented by the utility in Table C.13 of the Energy Safety Guidelines.[19] If the utility submits a Phase 2 Application that uses Subprojects, then the detailed RRU level data values submitted to the Commission should correspond with the Subproject data presented by the utility in Table C.14 of the Energy Safety Guidelines.[20]

If the Project has passed Screen 4 of the Energy Safety Guidelines, then the information presented at the Project or Subproject Level in the dataset submitted with either the Phase 2 Application or the six-month progress reports will correspond to the "Undergrounding as Scoped" concept defined in the Energy Safety Guidelines.[21]

For utilities that submit Projects in their Phase 2 Application and do not plan to break them into Subprojects later, the utility may continue reporting data at the Project level throughout both the Phase 2 Application and subsequent six-month progress reports. In these cases, the utility must still align its data with the appropriate Energy Safety Guidelines tables initially using Table C.11 for Screen 2 forecasts and then updating with Table C.13 data for Projects that pass Screen 4. RRU_IDs shall be created for the

[17] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-25 – C-26.

[18] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

[19] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-30 – C-32.

[20] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-33 – C-35.

[21] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at 44.

Project, and all reporting remains at the Project level. All data must be reported using the unique RRU_ID and OEIS_Project_IDs from the Phase 2 Application. (Figure 2)

Table 1 also collects Backcasted_Cost_Benefit_Ratio, Backcasted_Total_Mitigation_Benefit and Backcasted_Present_Value_Costs. In order to align with the concept of a Backcast as discussed in the RDF Proceeding, the following definition applies:

- Backcast: use updated inputs (e.g., new RRUs, new risk models) to recalculate Cost-Benefit Ratios, pre-mitigated risk, post-mitigated risk or other data elements. The goal of a Backcast is to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison.

When a utility elects to use the Subproject designation, the concept of a Backcast is essential in the SB-884 context to enable a consistent comparison between the forecasted RRU values reported in the progress reports and the backcasted RRU values that would have been calculated, had the RRU structure been applied in the Phase 2 Application using the data submitted at that time. For a utility that elects to use the Subproject designation the Backcasted_Total_Mitigation_Benefit, Backcasted_Present_Value_Costs and Backcasted_Cost_Benefit_Ratio fields may be left blank in the Phase 2 Application for OEIS_Project_IDs that have yet to establish an RRU_ID. For a utility that elects to align an RRU_ID with the OEIS_Project_ID (i.e. does not use the Subproject designation) there is no need to complete the Backcasted_Total_Mitigation_Benefit Backcasted_Present_Value_Costs, and Backcasted_Cost_Benefit_Ratio fields.

Table 1 also collects Unit_Cost_Percentage_Difference, calculated as:

$$\text{Unit\_Cost\_Percentage\_Difference} = \frac{\text{Forecasted Unit Cost in Phase 2 Application} - \text{Updated Unit Cost in progress report}}{\text{Initial Forecasted Unit Cost in Phase 2 Application}}$$

Where "Unit Costs" refers to the Average_Unit_Cost_per_Mile in Table 1

and also

CBR_Percentage_Difference calculated according to the following two scenarios:

a- Assuming the large electric corporation elects to use the Subproject designation and detailed Subproject data is not available, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and updated Cost_Benefit_Ratio in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Backcasted\_Cost\_Benefit\_Ratio} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Backcasted\_Cost\_Benefit\_Ratio}}$$

b- Assuming the large electric corporation elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application, this is calculated as the percentage difference forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent progress reports

$$\text{CBR\_Percentage\_Difference} = \frac{\text{Cost\_Benefit\_Ratio in Phase 2 Application} - \text{Updated Cost\_Benefit\_Ratio in the progress report}}{\text{Cost\_Benefit\_Ratio in Phase 2 Application}}$$

These two fields provide insight into the extent to which the CBR and Unit Cost have deviated from their original forecasted values, allowing for a clearer assessment of project performance and cost-effectiveness over time.

In Table 1, for each RRU (or project)[22] there will be one row for the utility's Undergrounding mitigation and one separate row for each alternative.[23]

All the Post-Mitigation fields must be completed by the utility using Screen 2 data or more updated data if available in the utility's Phase 2 Application. If the utility has data for scoped projects that have passed Screen 3 at the time of submitting its Phase 2 Application, then it must use that data. These fields will be updated by the utility in six-month progress reports as Screen 3 data becomes available.

For each RRU (or project), there should be one row representing the utility's undergrounding mitigation and one row for each alternative mitigation. Since each of these mitigation programs must be evaluated using three separate discount rates scenarios, this results in a total of nine rows per RRU (or project).

Table 2: Capital Cost Breakdown

This table breaks down the Capital Costs associated with mitigation efforts, including labor, materials, and permits, for projects under the Risk Reporting Unit. It provides detailed cost allocation to track expenditure efficiently. Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above.

Table 3: Risk Model Change Tracker

This table tracks changes and updates to the risk modeling and how that affects the risk associated with the assets and systems mitigated by the RRUs. Changes that include New Data Inputs to the Risk Model can include, but are not limited to, the addition of climate change variables or wildfire suppression related information. This allows us to compare current and previous risk models, risk scores and Costs across each of the six-month progress reports. It ensures transparency and accountability in how risks related to the electric grid are managed and reported.

Utilities regularly update their risk models. At times, the outputs (calculated risks) of new risk model versions might be substantially different from the previous version(s). In some cases, utilities have changed the length and names of each circuit segment from one risk model to another. To address the lack of clarity of the impact caused by changing risk models between the six-month progress reports, SPD created a template (Table 3) to track changes in each RRU (or Project) and how those changes would impact the calculation of risk from one risk model to the next. Table 3 collects data regarding changes in calculated risk, length, and name of each RRU (or Project), which utilities plan to include in its undergrounding projects. This enables analysis and comparison of data created across different risk models and supports comparison of such data across the six-month progress reports and even maybe among various proceedings where such data may be presented. Data

[22] Data may be submitted at the project level in the initial Application and at RRU level in subsequent progress reports when RRUs are created as described at page 4-5. This requirement follows for any other location in these Guidelines that state "RRU (or Project)".

[23] Please see the Proposed and Alternative Mitigations field described below and in the Excel data template attached to this Guideline.

may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above. This table complements some of the information presented in Table C.7 of the Energy Safety Expedited Undergrounding Plan Guidelines.[24]

Table 4: HFTD and Associated Asset

This table documents low-risk associated assets mitigated alongside primary electric grid infrastructure due to operational constraints or interconnected systems.[25] It includes associated Costs, miles, and Total Mitigation Benefit for comprehensive project management of risk on electric grid infrastructure.

Table 4 attempts to collect and clarify information regarding how the additional electric grid infrastructure associated assets can affect the Total Mitigation Benefit, Capital Costs, and CBR of the proposed RRU (or Project).-Data may be submitted at the project level in the Phase 2 Application and at RRU level when RRUs are created as described above

Table 5: Financial Inputs

This table provides financial parameters and metrics required to calculate and evaluate risk mitigations, including discount rates, the value of statistical life (VSL), and Present Value revenue requirements (PVRR). These inputs ensure that economic factors are systematically integrated into risk evaluations.

Table 6: Interruption Cost Estimate (ICE) Calculator Inputs

Since SB-884 requires undergrounding projects to be completed within the HFTD, the ICE Calculator inputs must be relevant only to the HFTD. The utility must also disaggregate their inputs according to HFTD and non-HFTD regions. This table provides inputs that can be integrated into the ICE Calculator 2.0 to estimate the cost per customer-minute interruption, by categorizing outages by time of day, season, and customer type. The ICE Calculator integrates key reliability metrics such as SAIDI and SAIFI to estimate the impact of service interruptions. This table requires the utility to calculate the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields as a $/CMI value which is further used to calculate the monetized value of electric reliability consequence within the HFTD.[26]

---

[24] Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, at C-12 – C-14.

[25] In Table 4, "low-risk" is defined as electric grid infrastructure assets whose risk level is below the "High-Risk Threshold" defined by Office of Energy Infrastructure Safety, 10-year Electrical Undergrounding Plan Guidelines, February 20, 2025, page 42.

[26] The calculation of Pre-mitigated and Post-mitigated Ignition and Outage Program Risk must include Pre-mitigated and Post-mitigated monetized values of electric reliability consequence, which must be calculated as a product of the $/CMI values from the Electric_Reliability_Valuation_Residential and Electric_Reliability_Valuation_Non_Residential fields in Table 6 and the following corresponding eight fields:

1. Ignition_Pre_Mitigated_Residential_Reliability_Consequences
2. Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences
3. Ignition_Post_Mitigated_Residential_Reliability_Consequences
4. Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences

Table Relationships

The data template Guidelines uses three primary key fields, RRU_ID, OEIS_Project_ID, and Undergrounding_Alternative_Mitigations, to connect Tables 1, 2, and 4 and ensure data consistency.
Every row in Tables 2 and 4 must correspond to a matching row in Table 1 using these fields. This structure supports accurate cost allocation, risk modeling, and asset tracking.
Table 3 uses RRU_ID and OEIS_Project_ID as its primary keys, which can be linked to Tables 1, 2, and 4 when tracking changes to risk models or asset definitions.

---

5. Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences
6. Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences
7. Outage_Program_Post_Mitigated_Residential_Reliability_Consequences
8. Outage_Program_Post_Mitigated_Non_Residential_Reliability_Consequences

Tables and Data Requirements

Table 1: Data Set

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the Risk Reporting Unit (RRU).[27]	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. OEIS_PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Circuit_Segment_ID	A unique value identifying the Circuit Segment ID on which this Undergrounding Project was defined. This is the same value as found in the Energy Safety Guidelines. If the Circuit Segment changes, the Circuit_Segment_ID remains identified with the original Circuit Segment, at the point the OEIS_PROJECT_ID is created	VARCHAR (255)
QDR_Circuit_Segment_ID	If the Circuit Segment was included in the most recent Quarterly Data Report submission as part of the WMP process, list the name used in that report. This must be the same value as found in the Energy Safety Guidelines in Table C.6.	VARCHAR (255)
GRC_Activity_Code	This is the Activity Code for the Proposed Mitigation relevant to this RRU. Field values are expected to utilize the following notational systems: PG&E: Maintenance Activity Type (MAT) SCE: Work Breakdown Structure (WBS) Sempra: Capital Programs are defined at the budget code; Expense programs are defined at the workpaper.[28]	VARCHAR (255)

[27] For more information see R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20. See also the discussion in R.20-07-013, Phase 4 Workshop 3, SPD Staff Proposal on Risk Mitigation Accountability Reports December 30 2024at 22.

[28] D.24-05-064, Appendix A, Row 28.

Field Name	Field Description	Field Value Constraints
Filings	List of all filing(s), including advice letters, where the RRU (or Project) is reported and a budget is requested including but not limited to a GRC application and Wildfire Mitigation and Catastrophic Events (WMCE) application.	TEXT
Customer_Count_Residential	Number of Residential customers served by the RRU (or Project)	INT
Customer_Count_Non_Residential	Number of Non-Residential customers served by the RRU (or Project)	INT
State_Legislative_District	State Legislative District of the service territory in which the RRU (or Project) is located.	VARCHAR (255)
Tranche_Level	The Tranche that includes the Assets or Systems that the Project[29] mitigates. Each Project can only mitigate the risk exhibited by Assets or Systems found in one Tranche. Tranches are the quintiles of Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE) for Wildfire Ignition Risk. The structure of the Tranche level to record in this field is represented as LoRE quintile and CoRE quintile that make up each tranche. Thus, the Tranche Level should be presented in the following shorthand: CoRE 1×LoRE 2 or CoRE 2×LoRE 1 If the utility has presented an alternative approach to tranches via a whitepaper in a previous RAMP Proceeding, it must create a clear and concise shorthand for the structure of the tranches.[30]	VARCHAR (255)

[29] Projects or RRUs reported in the Phase 2 Application. For any Projects reported in the Phase 2 Application, the corresponding RRUs are presumed to fall within the same Projects' Tranches.

[30] For more detail on the Tranche Level field, see D.24-05-064 at 26-33 and D.24-05-064, Appendix A, Row 14. Even if the utility records a Tranche Level in this field that accords with the tranche structure in its alternative approach to tranches, SPD reserves its right to challenge any alternative approach to tranches (See D.24-05-064 at 31).

Field Name	Field Description	Field Value Constraints
Asset_System_List	List of the unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU(or Project).[31] This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans. This field should also include the List of Associated Assets, if any, found in Table 4.	TEXT
Total_Circuit_Miles	Total number of pre-mitigated circuit miles included in the RRU (or Project).	REAL
Total_Circuit_Miles_UG	Total number of post-mitigated undergrounded circuit miles included in the RRU (or Project). This field only applies if Undergrounding_Alternative_Mitigations is listed as undergrounding mitigation.	REAL
Risk_Ranking	Ranking of the total pre-mitigated risk that is exhibited by the assets or systems that the RRU (or Project) mitigates (E.g., where the risk level of the assets or systems mitigated by the RRU (or Project) lies in comparison with risk level of the assets or systems mitigated by other RRUs (or Projects) across the entire Proposed Mitigation Program).	VARCHAR (255)
Scoping_Date	The year, month and day the utility intends to begin or did begin the scoping process of this mitigation for the RRU (or Project).	Date (YYYY-MM-DD)[32]
Start_Date	The year, month and day the utility intends to begin or did begin the construction or implementation of the RRU (or Project).	Date (YYYY-MM-DD)[33]
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following risk and cost analyses are carried out based on the value inputted within this field.[34] This field enables comparison of risk and cost analyses of alternative mitigations and the proposed undergrounding program for the same RRU (or Project).	VARCHAR (255)

[31] Asset is a retirement unit that exhibits risk, as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). A System is defined as a regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit. See R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 20.

[32] If the year, month and day is available, the utility must record this information in this field using the YYYY-MM-DD format.

[33] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

[34] For more information on alternative mitigation analysis, see D.18-12-014 at 34.

Field Name	Field Description	Field Value Constraints
Undergrounding_Mitigation_Justification1	Primary reason for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold; the Ignition Tail Risk Threshold, the High Frequency Outage Program Threshold, operational limitations, cost efficiency, and continuity.	VARCHAR (255)
Undergrounding_Mitigation_Justification2	Other reasons for choosing the Undergrounding mitigation that the utility proposed for the RRU (or Project). This field can include, but is not limited to, responses such as project-level thresholds required in the Energy Safety EUP Guidelines: the High-Risk Threshold, the Ignition Tail Risk Threshold; the High Frequency **Outage** Program Threshold, operational limitations, cost efficiency, and continuity. If a utility does not have a secondary reason for choosing the Undergrounding mitigation the utility should leave this field blank.	VARCHAR (255)
Status	Preset domain values to identify the current status of the RRU (or Project) are:[35] • Scoping: Identifying the size and timeline of the RRU (or Project) Scoping is the first step to providing visibility to the construction feasibility and possible execution timing. Designing: Delineation of a plan for implementing the RRU (or Project) including determining the RRU's (or Project) integration within existing infrastructure or operations and need for materials, training, or permitting. The costs for completing the RRU (or Project), including for permitting, labor and materials, are forecasted at this stage. • Permitting: The process of obtaining the rights and permits from relevant stakeholders to implement the RRU (or Project). This stage of the lifecycle also includes negotiating of contracts to implement the RRU (or Project) as well as final estimation of the costs associated with implementing the RRU (or Project).	VARCHAR (255)

[35] Information about the Status field can also be found in R.20-07-013, Phase 4 Workshop 1, SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8 2024 at 10-11.

Field Name	Field Description	Field Value Constraints
	• Construction/Implementation: During this stage a capital investment is built out or an operational activity is put into action. Capital investments are complete when they are used and useful. Operational activities could be an ongoing means of maintaining a level of risk.[36] • Post-Construction: For capital investments, there can be final paperwork and updates to asset registries after the scoped work is used and useful.[37]	
Used_and_Useful_Date	The year, month and day the utility intends to make or did make this RRU (or Project) used and useful. Used and useful means to be fully complete and providing service to customers.	Date (YYYY-MM-DD)[38]
CBR_Year_Zero	The year the risk and costs for the Undergrounding_Alternative_Mitigations program for the RRU (or Project) are discounted to.	INT
Useful_Life	The value of the useful life of the Undergrounding_Alternative_Mitigations program, represented as the number of years.	REAL
Ignition_Pre_Mitigated_Likelihood	The likelihood of Ignition before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL

[36] The "Construction/Implementation" status value corresponds to the "Ready for Construction" and "Construction in Progress" values in table C-14 of the *Energy Safety Guidelines*.

[37] The "Post-Construction" status value corresponds to the "Construction Completed" and "Overhead De-energized" values in table C-14 of the *Energy Safety Guidelines*.

[38] If the day is not yet confirmed, the utility must use 01 for the day (i.e. 2025-02-01).

Field Name	Field Description	Field Value Constraints
Ignition_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Likelihood	The likelihood of Ignition occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Ignition_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Ignition (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Ignition (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Ignition_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Ignition after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Likelihood	The likelihood of Outage Program occurring before Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Pre_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Non_Residential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Pre_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Likelihood	The likelihood of Outage Program occurring after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project).	REAL
Outage_Program_Post_Mitigated_Safety_Consequences	The unscaled expected value of Safety Consequences of Outage Program (e.g., injuries or fatalities) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Outage_Program_Post_Mitigated_Residential_Reliability_Consequences	The unscaled expected value of Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL
Outage_Program_Post_Mitigated_Non_Resdiential_Reliability_Consequences	The unscaled expected value of Non-Residential Reliability Consequences of Outage Program (e.g., Customer minutes interrupted) after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project) (Natural Units)	REAL

Field Name	Field Description	Field Value Constraints
Outage_Program_Post_Mitigated_Financial_Consequences	The unscaled expected value of Financial Consequences of Outage Program after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Natural Units)	REAL
Pre_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Ignition_Risk	Unscaled value of Ignition Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Outage_Program_Risk	Unscaled value of Outage Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Pre_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk before the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Post_Mitigated_Overall_Utility_Risk	Unscaled value of Overall Utility Risk after the Undergrounding_Alternative_Mitigations program is applied to the assets or system associated with this RRU (or Project). (Dollar Value)	REAL
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Total_Mitigation_Benefit, Present_Value_Capital_Costs, and Cost_Benefit_Ratio, among others. Input in this field shall include one row for each of the following three discount rate scenarios: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Ignition_Risk_Mitigation_Benefit	Present Value of the Wildfire Ignition Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Outage_Program_Risk_Mitigation_Benefit	Present Value of the Outage Program Risk Reduction from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL

Field Name	Field Description	Field Value Constraints
Net_OM_Costs_PV	Present Value of Operations and Maintenance (O&M) Cost Savings minus Present value of O&M New Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). Utilities may include Present Value of Net O&M Costs[39] as part of the Total_Mitigation_Benefit in the CBR's numerator for the RRU (or Project). (Dollar Value)	
Total_Mitigation_Benefit	Present Value of the Risk Reduction and potentially the Present Value of Net O&M Costs from the Undergrounding_Alternative_Mitigations program for the RRU (or Project). (Dollar Value)	REAL
Average_Unit_Cost_per_Mile	The average Unit Cost of the Undergrounding_Alternative_Mitigations program for the RRU (or Project) per mile.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Present_Value_Capital_Costs	Present Value of the Capital Costs (Total_CapEx) of the Undergrounding_Alternative_Mitigations program for the RRU (or Project).	REAL
Cost_Benefit_Ratio	Cost-Benefit Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	REAL
Backcasted_Total_Mitigation_Benefit	Recalculated Total_Mitigation_Benefit from the Undergrounding and Alternative Mitigations measure submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Backcasted_Present_Value_Capital_Costs	Recalculated Present_Value_Capital_Costs of the Proposed and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL

[39] The CBR calculation shall only be based on the incremental difference between the proposed project and the No-Build Baseline, both in terms of benefits and net costs (Net O&M Costs). No-Build Baseline represents a well-defined baseline scenario or what happens if no project or RRU is implemented.

Field Name	Field Description	Field Value Constraints
Backcasted_Cost_Benefit_Ratio	Recalculated Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations submitted in the Phase 2 Application based on the new inputs including but not limited to the RRU and/or new risk models and/or changes to the portion of the circuit scoped for mitigation (Dollar Value)	REAL
Unit_Cost_Percentage_Difference	The percentage difference between forecasted Average_Unit_Cost_per_Mile submitted in the Phase 2 Application and updated Unit Costs in the subsequent six-month progress reports.	REAL
CBR_Percentage_Difference	If the utility elects to use the Subproject designation, then this is calculated as the percentage difference between the Backcasted_Cost_Benefit_Ratio and the Cost_Benefit_Ratio presented in the subsequent six-month progress reports. If the utility elects not to use the Subproject designation or the detailed Subproject data is available in the Phase 2 Application this is calculated as the percentage difference between forecasted Cost_Benefit_Ratio submitted in the Phase 2 Application and the updated Cost_Benefit_Ratio presented in the subsequent six-month progress reports.	REAL
Risk_Model	Name and Version of Risk Model used to calculate Cost_Benefit_Ratio of the Undergrounding and Alternative Mitigations for the RRU (or Project).	VARCHAR (255)
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 2: Cost Breakdown

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
CapEx_Labor	Including all the required Engineering, Design, and Construction.	REAL
CapEx_Materials	All the required material s.	REAL
CapEx_Permits_Environmental	Permitting fees from local and state agencies that cover, for instance, but not limited to, environmental impact assessments.	REAL
CapEx_Other_Costs	Other Capital Expenditure that are not categorized in the rows above.	REAL
Total_CapEx	Total nominal value of the Capital expenditures of the Undergrounding_Alternative_Mitigations for the RRU. This value must be equal to Total_CapEx fields in Table 1.	REAL
Initial_Application_Total_Costs	Total nominal value of the Total_CapEx of the Undergrounding_Alternative_Mitigations for the RRU (or Project) that was presented in the Phase 2 Application to the Commission. This field should remain blank when the utility submits its Phase 2 Application.	REAL

Field Name	Field Description	Field Value Constraints
Reporting_Date	The date, the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding and Alternative Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 3: Risk Model Change Tracker

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Current_Asset_System_List	List of current unique Assets and/or the unique Systems that exhibit risk, which is mitigated by the RRU (or Project). The list in this field must be the same as the list in the Asset_System_List field in Table 1. This should include, but not limited to, the following examples: This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Current_Risk_Model	Name and Version of the updated Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project). (E.g., V2)	VARCHAR (255)
Current_Total_Miles	Total circuit miles under Current Risk Model for the RRU (or Project). This must be the same as the Total_Circuit_Miles in Table 1.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Current_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Current Risk Model for the RRU (or Project).	VARCHAR (255)
Current_Pre_Mitigated_Overall_Utility Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Current Risk Model. (Dollar Value). This must be the same as the Pre_Mitigated_Overall_Utility_Risk field presented in Table 1.	VARCHAR (255)
Current_Risk_Percentage	The Pre_Mitigated_Overall_Utility_Risk risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Current Risk Model.	VARCHAR (255)
Change_Type	Identification of how the circuit segment or partial circuit segment mitigated by the RRU has been defined and redefined since the last update: • New Data Inputs to Risk Model • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment • Merging of the circuit segment or partial circuit segment • Other	VARCHAR (255)
Change_Date	Date the Change_Type was implemented on the RRU (or Project).	Date (YYYY-MM-DD)

Field Name	Field Description	Field Value Constraints
Previous_Asset_System_List	For each RRU (or Project), if the value in the Change_Type field in this Table is one of the following: • New Construction of the circuit segment or partial circuit segment • Renaming of the circuit segment or partial circuit segment • Splitting of the circuit segment or partial circuit segment Merging of the circuit segment or partial circuit segment Then list the unique Assets and/or the unique Systems mitigated by the RRU(or Project), prior to the Change_Date. This should include, but not limited to, the following examples: Isolatable Circuit Segments or Circuit Segments, Poles and Spans	TEXT
Previous_Risk_Model	Name and Version of the previous Risk Model used to calculate the risk score for the assets mitigated by the RRU (or Project).	VARCHAR (255)
Previous_Total_Miles	Total circuit miles under the Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) under Previous Risk Model for the RRU (or Project).	VARCHAR (255)
Previous_Pre_Mitigated_Risk_Score	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) calculated under the Previous Risk Model. (Dollar Value)	VARCHAR (255)
Previous_Risk_Percentage	The pre-mitigated risk score for the assets mitigated by the RRU (or Project) divided by the total risk score calculated using the Previous Risk Model.	VARCHAR (255)

Field Name	Field Description	Field Value Constraints
Initial_Application_Total_Miles	Total number of circuit miles included in the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Initial_Application_Non_HFTD_Miles	Total miles (if any) that extend beyond the High Fire-Threat District (HFTD) for the RRU (or Project) from the Phase 2 Application to the Commission. Even if the total circuit miles do not change in a six-month progress report, this value must still be entered.	REAL
Reporting_Date	The date the risk and costs associated with the Current Risk Model are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs associated with the Current Risk Model are calculated.	Date (YYYY-MM-DD)

Table 4: HFTD and Associated Asset

Field Name	Field Description	Field Value Constraints
RRU_ID	A unique value identifying the RRU.	VARCHAR (255)
OEIS_Subproject_ID	A unique value identifying the Subproject. This is the same value as found in the Energy Safety Guidelines. The utility must retain the same Subproject ID over time. New Subprojects must receive new Subproject IDs which have not been used for any previously submitted Subproject.	VARCHAR (255)
OEIS_Project_ID	A unique value identifying the Undergrounding Project. This is the same value as found in the Energy Safety Guidelines. PROJECT_IDs must remain consistent over time and not be altered during updates.	VARCHAR (255)
Undergrounding_Alternative_Mitigations	This field must include the Undergrounding Mitigation and the Alternative Mitigations that the utility has considered for this RRU (or Project). All the following cost and risk analyses are carried on based on the value inputted within this field. This field enables comparing risk analyses of several alternative mitigations' options for the same RRU (or Project). This value must be identical with the Undergrounding_Alternative_Mitigations field in Table 1.	VARCHAR (255)
Associated_Assets	List of all connected low-risk Associated Assets that the utility plans to mitigate because of operational constraints or reasons other than the reducing risk (e.g., Service lines and Secondary lines).	TEXT
HFTD_Tier2_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 2.	REAL
HFTD_Tier3_Miles	If applicable, the total number of miles included in the RRU (or Project) located in HFTD Tier 3.	REAL
Wildfire_Rebuild_Miles	If applicable, the total number of miles included in the RRU (or Project) located in the Wildfire Rebuild Area.	REAL
Associated_Asset_Miles	Total associated asset miles included in the RRU (or Project) that the utility plans to mitigate.	REAL

Field Name	Field Description	Field Value Constraints
Discount_Rate_Scenario	The discount rate (See Table 5) used to calculate the Associated_Assets_Total_Mitigation_Benefit, and Associated_Assets_Present_Value_Capital_Costs, among others. Input in this field should be one of the following: • WACC Discount Rate Scenario • Societal Discount Rate Scenario • Hybrid Discount Rate Scenario	VARCHAR (255)
Associated_Assets_Present_Value_Capital_Costs	The Present Value of Capital Costs of the Undergrounding and Alternative Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Associated_Assets_Total_Mitigation_Benefit	The Present Value of the Risk Reduction and possible Present Value of Net O&M Costs of the Undergrounding_Alternative_Mitigations for all of the Associated Assets that the utility plans to mitigate.	REAL
Reporting_Date	The date the risk and Costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are reported.	Date (YYYY-MM-DD)
Calculated_Date	The date the risk and costs for the Undergrounding_Alternative_Mitigations for the RRU (or Project) are calculated.	Date (YYYY-MM-DD)

Table 5: Financial Inputs

Field Name	Field Description	Field Value Constraints
WACC_Discount_Rate	The Weighted Average Cost of Capital (WACC) Discount Rate Scenario the utility must use to calculate Present Value Benefits and Costs component of the CBR for an RRU (or Project).[40]	REAL
Societal_Discount_Rate	The Societal Discount Rate Scenario the utility must use to calculate the Present Value of Benefit and Costs component of the CBR for an RRU (or Project).[41]	REAL
VSL	Dollar value of statistical life used to monetize the Safety Consequence.[42]	REAL
Financial	Dollar value used to monetize the Financial Consequence, and it equals to $1.	REAL
PVRR	If applicable, PVRR or Present Value Revenue Requirement is the financial metric the utility used in its rate case and long-term planning to evaluate the cost implications of investments or programs over the life of the asset. Providing the PVRR is optional.	REAL
ICE_Calculator_Version	The ICE Calculator version that utility uses to estimate dollar value per customer minute interrupted	REAL
Reporting_Date	The date the Financial Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the financial Inputs are calculated	Date (YYYY-MM-DD)

[40] D.24-05-064 at 103.

[41] D.24-05-064 at 102-103.

[42] D.22-12-027, OP 2a.

Table 6: Interruption Cost Estimate Calculator Inputs[43]

Field Name	Field Description	Field Value Constraints
HFTD_Region	Interruption Cost Estimate calculator inputs broken down by HFTD and Non-HFTD. Acceptable values are: • HFTD • Non-HFTD	VARCHAR (255)
Affected_Customers_Residential	Total number of residential customers affected by risk events by HFTD_Region	REAL
Affected_Customers_Non_Residential	Total number of non-residential customers affected by risk events by HFTD_Region	REAL
Average_Annual_Usage_Residential	Average annual electricity usage in kilowatt-hours for residential customers by HFTD_Region	REAL
Average_Annual_Usage_Non_Residential	Average annual electricity usage in kilowatt-hours for non-residential customers by HFTD_Region	REAL
Residential_BUG	Percentage of residential customers with backup generation by HFTD_Region	REAL
Residential_work_from_Home	Percentage of residential customer working from home by HFTD_Region	REAL
Non_Residential_Manufacturing	Percentage of non-residential customers engaged in manufacturing by HFTD_Region	REAL
Non_Residential_Health_Social	Percentage of non-residential customers engaged in health care and Social Assistance by HFTD_Region	REAL
Outage_Summer	Percentage of outages occurring in the Summer, from June through September by HFTD_Region	REAL
Outage_Weekend	Percentage of outages occurring at the weekend by HFTD_Region	REAL

[43] D.22-12-027, OP 2b.

Field Name	Field Description	Field Value Constraints
Non-Residential_Advanced_Warning	Percentage of customers with advanced warning of an outage by HFTD_Region	REAL
SAIDI	System Average Interruption Duration Index by HFTD_Region. It is calculated by dividing the total minutes of customer interruptions by the total number of customers served.	REAL
SAIFI	System Average Interruption Frequency Index by HFTD_Region. It is calculated by dividing the total number of customer interruptions by the total number of customers served.	REAL
Electric_Reliability_Valuation_Residential	The Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator for each **HFTD_Region.**	REAL
Electric_Reliability_Valuation_Non_Residential	The Non-Residential dollar value per customer minute interrupted as estimated by the Interruption Cost Estimate Calculator by **HFTD_Region.**	REAL
Reporting_Date	The date the ICE Calculator Inputs are reported	Date (YYYY-MM-DD)
Calculated_Date	The date the ICE Calculator Inputs are calculated	Date (YYYY-MM-DD)

Appendix 2~~3~~: Statutory Requirements Cross-Reference

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(a)	The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section.	Purpose (p. 1), and Background (p.2)
8388.5(e)(1)	Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following:	Background (p.2), and Phase 2 - Application Submission and Review (p. ~~6~~8)
8388.5(e)(1)(A)	Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan.	Application Requirements (p. 9)
8388.5(e)(1)(B)	The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.	Application Requirements (p. ~~8~~10)
8388.5(e)(1)(C)	How the cost targets are expected to decline over time due to cost efficiencies and economies of scale.	Application Requirements (p. ~~8~~10)
8388.5(e)(1)(D)	A strategy for achieving cost reductions over time.	Application Requirements (p. ~~8~~10)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(e)(3)	In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening.	Application Requirements (p. ~~7~~9)
8388.5(e)(4)	Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days.	Public Workshop & Comments (p. ~~12~~13)
8388.5(e)(5)	On or before nine months, the commission shall review and approve or deny the application. Before approving the application, the commission may require the large electrical corporation to modify or modify and resubmit the application.	Background (p.2), and Application Conditional Approval, Denial, or Modification & Resubmittal (p. 5)
8388.5(e)(6)	The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable.	SB 884 Program Process and Requirements (p. 4-5), Conditions for Approval of Plan Costs (p. ~~12~~13), Phase 3 (p.~~ 13, ~~14), and Audit of the One-Way Balancing Account (p. ~~15 ~~16)

Code Section	Statutory Language	*Guidelines* Section (Page Number)
8388.5(i)(2)	The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan.	Background (p. 2), and Penalties (p. 17)
8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Background (p. 2), Application Requirements (p. 10), Conditions for Approval of Plan Costs (p. 12), Conditions for Approval of Recorded Costs in Memorandum Account (p. ~~14~~15), and Progress Report (p. ~~15~~18)