California Public
Utilities Commission

# Consolidated Stakeholder Responses to Informal Questions on CPUC's SB-884 Guidelines

SAFETY POLICY DIVISION

November 12 2024

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Edwin Schmitt
Safety Policy Division
California Public Utilities Commission
505 Van Ness Ave
San Francisco, CA 94102

**SUBJECT:** Clarification to Questions Regarding the CPUC SB-884 Guidelines

Dear Mr. Schmitt:

SCE has received the questions regarding the CPUC SB-884 Guidelines, letter dated October 14, 2024, entitled Request for Comments on Development of Guidelines for the 10-Year Electrical Undergrounding Distribution Infrastructure Plan (Undergrounding Plan). While SCE does not offer any responses to the voluntary set of informal questions, SCE respectfully submits clarification to the characterization of our Results of Operations (RO) Model. Please see the attached redlines for proposed corrections.

**CONCLUSION**

SCE appreciates the opportunity to provide clarification on the requested subject area. If you have questions, or require additional information, please contact me at gary.chen@sce.com.

Sincerely,

//s//
Gary Chen
Director, Safety & Infrastructure Policy

# Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

October 14 2024

## Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply giving a one-word answer.
- The reference to Office of Energy Infrastructure (OEIS) Guidelines in these questions is intended to refer to the Guidelines in place at the time these questions are asked. The Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57358&shareable=true. We acknowledge those Guidelines may change in the future.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf. The Commission may update the Guidelines in the future.
- Each "Background" section below represents only a partial summary of the relevant context. Please refer to other resources, inlcuding the OEIS Guidelines and the Commission's SB-884 Guidelines for further context before offering any responses.

## Definitions:

- **Circuit Segment**: a circuit segment refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[1]
- **Confirmed Project**: an Undergrounding Project that has completed Screen 3 (Project Risk Analysis), defined below.
- **Confirmed Project Polygon**: 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.
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884 cost recovery or submits an SB 884 Application or seeks OEIS approval for an SB 884 Plan.
- **Office of Energy Infrastructure (OEIS) Guidelines**: explained in "Instructions," above.
- **Plan Mitigation Objective**: the amount of change in risk (wildfire and reliability) that is necessary to meet the requirements contained in section 8388.5(d)(2).
- **Project-Level Standard**: the Risk Reduction Project Standard, the Reliability Increase Project Standard, and the Tail Risk Mitigation Project Standard.
- **Protective Equipment and Device Settings (PEDS)**: advanced safety settings implemented by electric IOUs on electric utility powerlines to reduce wildfire risk.[2]
- **Retired pole**: An electric pole that has been removed from ratebase.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[3]

[1] This concept refers to the same concept found within the OEIS Guidelines Appendix A
[2] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings
[3] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 16-17

- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process.[4]
- **Screen 4 (Project Prioritization):** the Electrical Undergrounding Plan (EUP) must set forth a means of prioritization and its definition for each of the factors in section 8388.5(c)(2), i.e. wildfire risk reduction, public safety, cost efficiency and reliability benefits.[5]
- **Topped poles**: the process during an undergrounding project of cutting the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried.
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the CPUC Data Appendix 1 information completed.

## A. Results of Operation (RO) Model

**Background:**

The Commission requires IOUs seeking rate increases to reflect the results of their requests in what are called results of operation models ("RO models"). An RO model may illustrate ~~rate~~ revenue requirement ~~impacts~~ across all of the IOU's lines of business, such as in a General Rate Case (GRC), or it may model revenue requirement ~~impacts~~ for a particular program in a "mini RO model." Both models present the utility's forecasted revenue requirement for its operations. The forecasted revenue requirement is calculated through a computer model called the RO model. The major components of the GRC RO model include:

- Rate Base
  - Includes information related to Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve;
- Return on Rate Base;
- Taxes;
- Other Operating Revenues and the Rate Base component.[6]

The Commission stated in Decision (D.) 00-07-050 that RO models should be user-friendly and facilitate the Commission's ability to quickly calculate the revenue requirement for various decision scenarios and should easily be able to accomplish the following:

- Change depreciation rates;
- Move unbundled cost categories (UCCs) between major functional groups (i.e., distribution, generation, etc.);
- Calculate the lead-lag portion of working cash;
- Calculate all taxes and tax depreciation;
- Make plant adjustments, including adjustments to beginning-of-year plant; and
- Calculate a distribution Revenue Requirement and Summary of Earnings.[7]

Standalone RO models are used to generate cost recovery requests in Applications to the Commission outside of General Rate Case (GRC) Proceedings. SCE's standalone RO model is distinct and separate from the main RO model that SCE uses in its GRC Applications. ~~The Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) standalone RO model approach is completely integrated within their the main GRC RO model. SCE has used this integrated RO model approach to generate revenue requests in, for instance, a recent application to recover costs related to wildfire mitigation, vegetation management;~~

[4] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 17

[5] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 18

[6] For an example of how this is discussed in a GRC Decision see D.20-12-005 at 334-335.

[7] See D.00-07-050 at 11.

Note: In A.24-04-005, SCE requests to recover incremental recorded costs that exceed the GRC authorized amounts associated with wildfire mitigation activities. A standalone RO model was not needed because the authorized amounts reside in the GRC RO model.

~~catastrophic events, and wildfire liability insurance.[8]~~ In the context of wildfire mitigation investments, SDG&E has not filed a standalone cost recovery application.

PG&E utilizes what it calls a mini-RO model to generate revenue requests. This mini-RO model is distinct and separate from the main RO model that PG&E uses in its GRC Applications. In the context of wildfire mitigation investments, PG&E has used this mini-RO model approach in its 2023 cost recovery Application related to wildfire and gas safety.[9] Commission Staff understands that PG&E intends to use the mini-RO model approach to generate revenue requests for SB-884 Applications. According to PG&E, a mini-RO model is distinct from the RO models submitted to the GRC in the following ways:

- The standard mini-RO Model may be tailored for a separately funded/incremental rate case for specific types of costs and applicable income tax rules.
- The mini-RO Models used in separately funded/incremental proceedings cover a proposed revenue recovery period.
- All inputs and revenue requirement calculations are integrated within a single Excel model for simplicity and efficiency.[10]

**Questions:**

1. Should a standalone RO model be used for generating a revenue requirement for an SB-884 application, or is another approach more appropriate? How should each of the IOUs' approaches be harmonized to have one standard for ratemaking in this process? In your response, discuss the need to encourage transparency and stakeholder holder engagement to ensure that rate impacts are incremental to other funding granted to the IOU, accurately represented and litigated in the process of generating a revenue requirement.

2. Is the mini-RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

3. Is the integrated RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

4. Through data requests, PG&E has informed Commission Staff that PG&E's mini-RO model does not account for depreciation costs associated with topped poles.[11] These factors would be accounted for in PG&E's GRC RO model. According to PG&E, each of its GRC Applications includes a depreciation study which determines the depreciation rates and is the proper route to account for topped and retired poles. With the mini-RO model being distinct and separate from the main GRC RO model, what challenges might this create for ensuring that the depreciation costs of topped poles is properly accounted for within a utility's rate base? How should these challenges be addressed in the SB-884 Guidelines?

5. Assume that a Commission Decision on a utility's SB-884 Application approves Project A to underground 1 mile of overhead (OH) line that is still in the utility's ratebase.[12] In a future GRC

[8] A.24-04-005
[9] A.23-06-008
[10] PG&E response to data request EUP_DR_SPD_011_Q001-012 at 1-2
[11] Topped poles refers to the process during an undergrounding project of cutting of the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried. See PG&E response to data request DRU14160_Case_EUP_DR_SPD_008, Question 1 at 1.
[12] A utility's rate base is the investment upon which the utility can earn its rate of return.

Application Proceeding, how would the Commission determine that the utililty had appropriately removed the 1 mile of OH line from the ratebase if the SB-884 Application was based on the mini-RO model?

6. PG&E has informed Commission Staff that it does not submit a depreciation study as testimony in an Application where the revenue request is generated by a mini-RO model. Should the Commission require a utility to submit a depreciation study along with an SB-884 Application? If so, should the utility be required to update certain parts of the depreciation study submitted with the utility's most recent GRC, such as that related to grid hardening and other wildfire mitigations? Explain your answer.

## B. Third Party Funding

1. How should the IOUs account for third-party funding they seek or receive, as required by Public Utilities Code Section 8388.5(j), for undergrounding projects to ensure the requirements of the Commission's SB-884 Guidelines and Senate Bill (SB) 884 are met?

   a. How should ratepayer savings attributable to third party funding be accounted for?
      i. Should they appear as an offset to the proposed revenue requirement in a mini-RO model?
      ii. Should they appear in the IOU's next GRC?
      iii. Should there be a reporting requirement for the utilities to report on third-party funding? If so, what information should be included in this report?

   b. Should the IOUs treat third-party funded plants as contributed plants? Why and why not?

   c. Describe the IOUs' accounting for third-party funded plants in regards to utility plant accounts, and depreciation and amortization reserves.

2. Should an IOU file an advice letter documenting which annual cost caps are reduced by third-party funding? If so, how often should it be filed and what should the advice letter include?

## C. CBR Threshold

**Background:**

The Cost-Benefit Ratio (CBR) is described in D.24-05-064 and D.22-12-027 of Rulemaking (R.) 20-07-013. CBR is a financial metric used to evaluate the efficiency of a project by comparing the benefits it offers (in this case, wildfire risk reduction and reliability enhancement) to its associated costs (cost of undergrounding overhead lines). The greater a CBR is relative to 1.0, the more its benefits outweigh its costs. Thus, as an illustrative example, a project with a CBR of 7.0 has benefits that exceed its costs by seven times, whereas a project with a CBR of 1.0 means costs and benefits are equal, and a project with a CBR of less than 1.0 means that its costs exceed its benefits. If an IOU were allowed to deploy a project with a CBR less than 1.0, it could be due to operational constraints. For example, in order to complete a project, the IOU may be required to perform work on other circuits segments upstream or downstream from the circuit segment with a high CBR. Those upstream or downstream circuit segments may have low CBRs even though they are necessary to the project, and therefore they may bring down the total CBR of a project. Sometimes projects with a CBR of 1.0 or below would be proposed because they are associated with high-risk overhead lines that face constraints such as operational considerations or legal statutes.[13]

**Questions:**

1. Should IOUs be required to provide additional justifications when they want to install projects that have either:

    a. Low CBRs[14] (in comparison to other UG projects in that IOU's application);

    b. CBRs below 1.0; or

    c. Lower CBRs compared to the CBRs of alternative wildfire mitigations that do not include undergrounding (such as covered conductor, remote fault detection technologies or high impedance fault detection)?

        i. And in each case (for Questions (1) (a)-(c) above) where the answer is yes, please explain why and what those additional justifications might be.

        ii. Furthermore, if the 1.0 threshold referenced in question (1)(b) above is too low from your perspective, and if IOUs should therefore be required to provide additional justifications when they want to install projects that have CBR thresholds greater than 1.0, then at what threshold above 1.0 should the additional justifications no longer be necessary and why?

## D. Audit

**Background:**

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain conditions (Phase 2 Conditions) in order for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit. If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. The details of this audit, including who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order.

**Questions:**

1. Please expand on what the main objectives of the audit should be, in addition to ensuring the Phase 2 Conditions have been met?

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[13] Associated circuit segments refer to the high-risk circuit segments which might be the primary reason to hardening the Low CBR circuit in the first place.

[14] "Low CBR" can be defined as projects whose CBRs are below a certain threshold (e.g., 2 standard deviations, where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average CBRs of other projects offering the same type of mitigation.

[15] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

a. What language will best ensure that the audit achieves its various goals, including determining whether the costs booked to the balancing account meet the Phase 2 Conditions?

b. Are the specific conditions and other criteria for the audit clearly outlined in the Commission's SB-884 Guidelines to help determine whether costs in question meet such criteria?

c. Should audit objectives include verifying that claimed IOU activities and projects have been completed as claimed?
   i. Would satellite imagery or other photographic evidence be sufficient to perform this verification?

d. What are the project characteristics (e.g. projects with low CBR) that the audit should address?
   i. Should the CBR stated in the Application be verified during the audit?

e. Should the auditor be required to follow professional auditing standards to meet the audit objectives; and if so, which ones?

2. In D.23-02-017, the Commission explained that costs are incremental if "in addition to completing the planned work that underlies the authorized costs, the utility had to procure additional resources, be they in labor or materials, to complete the new activity. The existence and completion of a new activity by itself does not prove the cost was incremental."[16]

   a. With this Decision in mind, how should the Guidelines ensure that the scope of the audit addresses whether the costs in an SB-884 Application are incremental to other revenue requests presented to the Commission in a GRC or other cost recovery application? Please provide suggested language.

   b. Should an IOU be required to present costs related to straight time labor, overtime labor, contracted labor or other labor-related costs in its showing of incrementality in an SB-884 Application?

   c. Should audit Guidelines address the issue of incrementality between the Balancing Account and Memo Account authorized in Resolution SPD-15 and established through a utility's SB-884 Application? If so, what language would you recommend?

   d. Should an IOU be required to document its methodology of tracking incremental costs?
      i. Should all IOUs be required to use consistent methodologies in tracking these incremental costs?
      ii. Should an IOU be required to document how the GRC-approved cost categories line up with account categories or projects claimed to provide support for its methodology of tracking incremental costs?

3. When should the audit of the balancing account occur?

   a. Should the audit begin after the Commission adopts a Decision in the utility's GRC Application proceeding; if so, when?

4. How often should the audit of the balancing account occur?

[16] D.23-02-017 at 27.

a. Should an audit of the balancing account be limited to once every four years to correspond with the GRC cycle?

b. If an audit of the balancing account should occur multiple times in a GRC cycle, explain how many times and the rationale for requiring multiple audits within a utility's GRC cycle?

5. The Commission's SB-884 Guidelines state that if the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund to ratepayers.

    a. Should language be added to the SB-884 Guidelines that explicitly describes the method for a refund, such as a true-up in the utility's rates after the audit has been completed? If yes, provide suggested language along with a justification. If no, explain why.

6. The Commission's SB-884 Guidelines require the utility to identify any wildfire mitigation cost savings in its Application.[17] How should the claim of cost savings be addressed by the audit?

7. Should the Commission consider other possible audits completed previously by either third parties or internal IOU auditors as part of the assessment in determining appropriateness and reasonableness of claimed costs in question?

## E. Net Present Value (NPV) Calculations and Sensitivity Analyses

**Background:**

**NPV Costs and Revenue Requirement**
Because undergrounding projects take a long time to complete and have long useful lives, their CBRs are calculated in present day dollars, even if the cost will be much higher in the future. This calculation is called the NPV of costs from the revenue requirement and involves discounting future revenue requirements (which represent the utility's future costs) to their present value. Utilities need to identify and report the future revenue requirements: these are the yearly costs the utility expects to recover from ratepayers, typically including operational expenses, capital expenditures, and a return on investment. Utilities need to determine and report the discount rate(s) representing the time value of money and how NPV costs are calculated.

**Sensitivity Analyses**
A sensitivity analysis is a technique used to understand how different inputs into a model impact the outcome or results. For example, sensitivity analysis is often used in arriving at a CBR and shows how sensitive the projected costs, benefits or risks are to changes in the input assumptions.

**AB 2847**
Assembly Bill (AB) 2847 (Stats. 2024, Ch. 578) requires the following:

> Pub. Util. Code Section 739.15(a) The commission shall determine in a scoping ruling or other ruling whether an application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures requires the estimates described in subdivision (b).
>
> (b) An application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures, including an application for conditional approval of the costs of an undergrounding plan pursuant to Section 8388.5, shall include, if the commission pursuant to

[17] For details see SPD-15, SB-884 Program: CPUC Guidelines at 7.

subdivision (a) determines that the estimates are required, the electrical corporation's or gas corporation's best estimate of both of the following:

(1) The application's impact on the electrical corporation's or gas corporation's annual revenue requirement for each year that the capital expenditures described in the application are expected to remain in the application's rate base if the application is approved or conditionally approved.

(2) The net present value of the application's impact on the electrical corporation's or gas corporation's annual revenue requirement provided pursuant to paragraph (1).

(c) The commission shall require the electrical corporation or gas corporation to provide supporting workpapers and calculations for the estimates described in subdivision (b).[18]

**Questions:**

1. In the context of AB 2847, should the utilities calculate and report their revenue requirement and NPVs costs in an SB-884 Application using a consistent method across IOUs? Explain your answer.

2. Considering the D.24-05-064 requirement that the IOUs present the results of three discount rate scenarios for their CBR calculation,[19] should the utilities be required to present NPV Benefits, NPV Costs, and CBR using each of the three discount rates in their SB-884 Applications?

3. Given that different mitigation projects may start at different times and become used and useful[20] in different years, how should the utility incorporate these differing timeframes into the calculation of NPV Costs and NPV Benefits?

4. Should the Commission require IOUs to report and compare NPV Costs and NPV Benefits, and CBR of undergrounding in a consistent mannner across IOUs?

    a. Do the current Commission SB-884 Guidelines allow for consistent comparison between undergrounding projects and alternatives? If yes, explain why. If not, why not?

    b. Do the current Commission Guidelines allow for accurate comparison between undergrounding projects and alternatives? Explain your answer.

## F. Changes to a Utility's Expedited Undergrounding Plan

**Background:**

OEIS' revised Electrical Undergrounding Plan (EUP) guidelines allow for changes to the IOU's undergrounding Plans to occur throughout the ten year time period of any particular Plan. For example, Guideline 2.7.5.2 provides that model version changes are "qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a backtest report (see Section 2.7.6 )." OEIS defines "calibration changes" as "smaller changes that do not significantly impact the Model Risk Landscape and

[18] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB2847

[19] See D.24-05-064 at 102-105. The utilities are required to calculate CBR for each mitigation using three discount rate scenarios: a) Societal Discount Rate Scenario, b) Weighted-Average Cost of Capital Discount Rate Scenario, and c) Hybrid Discount Rate Scenario.

[20] The used and useful year of a project is the year that the project is completed and energized.

only require the establishment of a new Baseline."[21] In Section 2.4.2.4 of the OEIS Guidelines, a Confirmed Project is defined by the boundaries of the Confirmed Project Polygon that encompasses the entire Circuit Segment on which the Undergrounding Project is defined.[22] If an IOU changes its project, the polygon (or other illustration of where and how the undergrounding project will occur) is not updated. However, the OEIS Guidelines in Section 2.3.4 also state that if the scope of a project changes to include sections outside of the Confirmed Project Polygon (e.g., if a portion of another Circuit Segment outside of the approved Confirmed Project Polygon is added to a project), the utility can calculate risk reduction by using the risk reduction for "the full (expanded) project" for determining the contribution towards the Plan Mitigation Objective, and yet the utility may only use "the work inside the original Confirmed Project Polygon" for determining whether the project meets the Project-Level Standard. Hence, cost and risk reduction calculations, that will provide the substantial factual basis from which the Commission will deliberate on to make its Phase 2 Decision, may be impacted by potential changes to the scope of projects after a Phase 2 Decision is issued.

**Questions:**

1. How should the Commission ensure and evaluate that the costs, risk reduction, and CBR of a project are accurately calculated when portions of Circuit Segments are added or modified after:

    a. an IOU submits an SB-884 Application to the CPUC?

        i. If an IOU changes its projects after obtaining OEIS approval of its EUP, how should the utility incorporate these changes in its Application for cost recovery at the CPUC?

    b. the CPUC adopts a Phase 2 Decision on an SB-884 Application?

        i. If an IOU changes a project after the adoption of a Phase 2 Decision, for example due to circuit expansion, risk model change, or operational constraints, how should any additional costs, or cost reductions, be accounted for? Explain your answer.

        ii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC require an IOU to report changes to the project's CBRs? Should there be a threshold over which CBR changes should be reported?

        iii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC address projects that no longer meet the the conditional approval stipulated in the Phase 2 Decision?

    c. an audit of the SB-884 Application has concluded?

    d. an IOU submits an Application for a just and reasonableness review of its SB-884 Memorandum Account?

[21] See OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.5.2 at 36.
[22] OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

2. Considering the implications of OEIS Guidelines Section 2.3.4 described above, when the utility calculates CBRs, should the utility use the NPV Benefits calculated for the risk reduction from:

    a. "the full (expanded) project"? Why or why not?

    b. "the work inside the original Confirmed Project Polygon"? Why or why not?

    c. Would your answers to 2a. and 2b. depend on circumstances, such as when the CBR is calculated? Please describe the circumstance and explain why it would affect the answer to 2a. and 2b

3. There are limits on Commission staff's ability to make changes to a Commission Decision or Resolution pursuant to delegated authority. D.02-02-049 and GO 96-B Rule 7.6.1 describe the difference between discretionary and ministerial action.[23]

    a. If an IOU seeks to change an undergrounding project, is there any change that you believe could be deemed ministerial with approval delegated to staff? If so, describe such ministerial changes.

    b. If an IOU seeks to change an undergrounding project is it your view that a Petition for Modification (PFM) is required?[24] Does your answer depend on the type of change? If so, please explain .

4. The current OEIS guidelines allows for a Confirmed Project to change within the 10-year period of the EUP.[25] How should the Commission address an undergrounding project where the trench length exceeds the forecasted estimate submitted to the Commission in an SB-884 Application?

    a. Should there be a trench length excedence threshold that:
        i. requires the project to be audited? Explain your answer.
        ii. triggers a PFM requirement? Explain your answer.

    b. What data could be used to determine whether or not the excedence threshold has been surpassed?
        i. Would the data collected through the OEIS Guidelines be sufficient? Why or why not?

5. Are the model version changes and calibration changes described in OEIS Guidelines 2.7.5.2 relevant to how the CPUC should handle undergrounding plan changes? Explain your position.

    a. How, if at all, should an IOU report to the CPUC and stakeholders on updates to a model, including the Outage Program Risk model described in Section 2.7 of the OEIS SB-884 Guidelines,[26] which are still in development and not submitted or approved as part of an IOU's Wildfire Mititgation Plan (WMP)?

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[23] While discretionary and ministerial actions vary based on the subject matter, they broadly mean the following. Ministerial actions are actions which are made based on pre-defined criteria. These actions can be carried out by Industry Divisions, such as Safety Policy Division and Energy Division. Agencies cannot delegate discretionary action without statutory authority.

[24] PFMs asks the Commission to make changes to an issued decision. See CPUC Rules of Practice and Procedure Rule 16.4.

[25] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

[26] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7 at 24-41.

6. TURN stated in its May 29, 2024 comments on the OEIS Draft Guidelines that changes of at least 20% of circuits included in the EUP should trigger a new comment period of 10-15 days.[27] Cal Advocates similarly stated in its August 9, 2024 comments on PG&E's topics for Discussion of Revised Draft Guidelines that at each semiannual progress report new thresholds and risk models be used to re-evaluate the cost-effectiveness of projects in the current EUP work plan, to ensure that the thresholds are meaningful and the project prioritization evolves to reflect current information.[28]

    a. State your position on these comments.

## G. How to Address Circuit Segments and Project Polygons

**Background:**

Section 2.8.1 of the OEIS Guidelines requires IOUs to furnish updated tabular data with each Progress Report. Section 2.8.3 of the OEIS Guidelines requires IOUs to furnish updated information reported in geodatabase submissions in each Progress Report including the latest version of their projects in polygon form. Section 2.7.6 of the OEIS Guidelines require the IOUs to retain models and calibrations data for the lifetime of the program, but the OEIS Guidelines do not have an explicit retention policy regarding tabular data and geodatabase submission updates.

**Questions:**

1. Should the CPUC Guidelines include an explicit retention policy that requires the utilities to retain updates to the tabular data and geodatabase with each Progress Report for the lifetime of the program?

2. Should the polygons be updated after the Commission adopts a Decision on the utility's application? Why or why not?

## H. Number of Alternatives

**Background:**

Undergrounding refers to the practice of placing utility infrastructure, such as power lines, underground instead of using overhead poles and wires. Covered conductor refers to overhead lines encased with material thick enough to reduce the likelihood of sparks or faults, which in turn reduces the likelihood of causing fires or outages. Protection devices are switches, reclosers or sectionalizers installed on overhead power lines to isolate faults or shut off power, minimizing the scope and impact of outages or incidents. Other mitigations include, but are not limited to, practices such as vegetation management, which involves trimming or removing vegetation near power lines, and pole enhancements such as stronger, more fire-resistant materials (e.g., steel poles instead of wooden poles).

[27] See TURN Opening Comments on Draft 10-Year Electrical Undergrounding Plans Guidelines, May 29 2024 at 3 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56734&shareable=true

[28] See Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines, August 9 2024 at 2 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57175&shareable=true

The OEIS guidelines require an IOU to compare two alternative mitigations.[29] An alternative to this approach is the idea of requiring utilities to present an "exhaustive list" of all possible mitigations, which could offer more comprehensive risk analysis but may be resource intensive.

**Questions:**

1. Should the CPUC limit alternatives to those required by OEIS, or should it require additional mitigation alternatives to be presented? Explain your answer.

2. Should the CPUC allow utilities to tailor the number of alternatives analyzed based on specific circumstances, such as regional risks, or should a standard approach for all projects be required? Explain your answer.

3. How can the CPUC ensure that the analysis of alternative mitigations clearly, comprehensively and accurately compares costs and benefits of undergrounding, covered conductor, protection devices, and other mitigations?

4. Are there standards or regulations the CPUC should consider requiring for IOU projects and altenative mitigations, similar to Australia's Electricity Safety Bushfire Mitigation Regulations 2017[30]?

## I. Compliance with the Application

1. If a project does not adhere to the timeline for completion included in its Application to the Commission, how should the Commission address this delay, and should delay affect cost recovery for that project?

## J. How to Address Costs if an Application or Projects are Rejected or Abandoned

1. Undergrounding preparation costs could include permitting, site or right of way acquisition, labor/hiring, planning, environmental review and other operational costs incurred in planning an undergrounding project. What is your view on how the Commission should treat undergrounding preparation costs if the undergrounding project is not carried out and/or completed?

2. Does your answer to Question J.1 depend on why the project was not carried out and/or completed? For instance:

   a. Project denied by OEIS;

   b. Project funding disapproved by CPUC;

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[29] Alternative Mitigation 1 must include covered conductor in combination with some type of PEDS. Alternative Mitigation 2 must include one other mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1, including but not limited to remote fault detection technologies and high impedance fault detection. For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.10 at 41.

[30] Electricity Safety (Bushfire Mitigation Duties) Regulations 2017 (legislation.vic.gov.au). These Regulations set guidelines and standards for protective devices' performance (e.g., how fast switches should close and reduce voltage on a faulted line) and for other mitigation measures.

c. Project abandoned by IOU;or

d. New legislation prevents the project from being carried out.

3. Generally, costs incurred prior to plant being placed in service and deemed used and useful are recorded as Allowance for Funds Used During Construction (AFUDC) costs. AFUDC is typically used for projects that are expected to be constructed and be placed into rate base so they can earn a rate of return.

   a. Should SB 884 undergrounding costs be treated as AFUDC if a project is rejected by OEIS or cost recovery for the project is denied by the CPUC?

   b. Should AFUDC costs related to a project that is rejected, denied or abandoned be recovered in an IOU's General Rate Case or should the CPUC solely determine cost recovery for costs of projects that are not yet completed in SB 884 project applications?

   c. How should IOUs record costs related to projects that are in progress but not yet completed to avoid retroactive ratemaking?[31] IOUs responding shall specify in which account they plan to record pre-Application costs and how they propose to seek cost recovery for those costs if a project is rejected, denied or abandoned.

4. Should the CPUC impose a requirement that if an SB-884 project reaches a certain stage it needs to be completed? Explain your answer.

5. Should the Commission develop guidelines pertinent to abandoned projects (i.e., projects the IOU opts not to complete or use)? If so, what positions should the guidelines take?

   a. Should any relate to cost recovery; and if so what positions should they take?

   b. Should any relate to removal of facilities; and if so what positions should they take?

   c. What other guidelines should there be?

6. Should the CPUC impose a requirement that a project that has remained at a particular stage for more than a certain period should be reported as abandoned?

   a. If so, what should the CPUC require regarding cost recovery and other activity on that project?

   b. If so, at what stage(s) of the project should it be reported as abandoned? How much time should elapse within that stage for the CPUC to require the utility to report the project as abandoned?

   c. If not, why not?

7. New Jersey has a rule that relates to cost recovery for abandoned projects that were part of an accelerated level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing, critical water distribution components that enhance safety, reliability, water quality, system flows and pressure, and/or conservation.

   The rule states:

[31] Rates are set on the cost of doing business which the utility files in a rate case. The resulting Decision of the rate case is applied going forward and is never retroactive.

If within three years after the effective date of a Foundational Filing, a water utility has not filed a petition in accordance with the Board's rules for the setting of its base rates, all interim charges collected under the DSIC rate shall be deemed an over-recovery, and shall be credited to customers in accordance with this subchapter. A water utility may seek recovery of such projects in the ordinary course through its next base rate case. Notwithstanding the above, a water utility may continue to collect a DSIC charge during a pending rate case filed in accordance with this section.[32]

a. Should the CPUC develop a similar requirement for SB 884 undergrounding projects? Explain your answer.

[32] New Jersey Administrative Code 14:9-10.4 (e) - DSIC Foundational Filing https://casetext.com/regulation/new-jersey-administrative-code/title-14-public-utilities/chapter-9-water-and-wastewater/subchapter-10-distribution-system-improvement-charge/section-149-104-dsic-foundational-filing

VIA E-MAIL
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November 12, 2024

Edwin Schmitt
Public Utilities Regulatory Analyst
Safety Policy Division
Risk Assessment and Safety Analytics
California Public Utilities Commission

**Re: AT&T, CalBroadband, Crown Castle Fiber, and Sonic Telecom Voluntary Response to Informal Questions Issued October 14, 2024**

Dear Mr. Schmitt:

Pacific Bell Telephone Company d/b/a AT&T California ("AT&T"), the California Broadband & Video Association ("CalBroadband"),[1] Crown Castle Fiber LLC ("Crown Castle"), and Sonic Telecom, LLC (collectively, "Joint Responders") submit this voluntary response to the informal "*Questions for Stakeholders Regarding the CPUC SB-884 Guidelines*" dated October 14, 2024. This response is limited to answering one question that could significantly impact the communications industry.

## I. INTRODUCTION AND BACKGROUND

Undergrounding electric distribution infrastructure does not occur in a vacuum. Other entities – including communications service providers, electric ratepayers, and the public at large are directly impacted.[2] Indeed, the California Public Utilities Commission ("Commission") has acknowledged that its evaluation of undergrounding proposals "necessarily involves evaluating the soundness of [an IOU's] proposed work plans … and whether [the undergrounding proposal] will have economic or service impacts on other businesses that the Commission must also take into consideration."[3]

Broadband expansion requires attaching communications equipment to vertical assets such as utility poles.[4] The Joint Responders rely on utility poles that are solely or jointly owned by the IOUs to deliver their services.[5] Certain communications equipment, such as Wi-Fi devices and

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[1] The California Broadband & Video Association ("CalBroadband") is a trade association consisting of cable companies that have invested over $45 billion dollars in California infrastructure over the last two decades to provide video, voice, and Internet service to millions of customers across the state.
[2] *See* A.21-06-021, PG&E General Rate Case ("GRC"), AT&T GRC Opening Brief at 2-3 (Nov. 4, 2022), *available at*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K526/498526065.PDF.
[3] Decision ("D.") 23-11-069 at 290.
[4] *See* Comcast Opening Brief (GRC) at 23, *available at:* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K338/498338970.PDF.
[5] *See Id.* at 3, 22.

cell antennas that provide hotspots and broadband, cannot operate below ground. If an IOU removes its poles as part of an undergrounding project, some communications providers with attachments on those poles will need to take action and could be faced with the prospect of either undergrounding with the IOU or discontinuing service in that area.[6] Communications facilities and equipment do not pose an ignition risk, therefore there is ***no*** wildfire prevention benefit from also undergrounding communications facilities.[7]

Moreover, forcing communications providers to absorb undergrounding costs would divert finite resources that otherwise could be used for other purposes, such as the deployment of new broadband infrastructure to meet California's connection goals. This could distort competitive forces and complicate investment decisions, which could result in less or delayed availability of advanced communications services to a significant number of California customers.[8]

The Joint Responders also note that there are a number of alternatives to undergrounding that could reduce wildfire risks with less impact on the environment and in a more efficient, cost-effective manner.[9] For example, a recent Joint IOU Covered Conductor Working Group report found that covered conductors "are up to 100% effective at preventing arcing and ignition in tested scenarios at rated voltages."[10]

## II. VOLUNTARY RESPONSE TO QUESTION C – COST-BENEFIT RATIO THRESHOLD

The specific questions relating to the Cost-Benefit Ratio ("CBR") Threshold focus on when the IOUs should provide additional justification for certain mitigation projects. However, the Joint Responders would like to raise a more fundamental issue relating to the CBR.

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6 *See Id.; see also* AT&T Opening Brief (GRC) at 2-3.

7 *See* D.23-11-069 at 288 ("No party presents evidence of communications facilities' risk of wildfire ignition."); *see also* CAL FIRE, California Power Line Fire Prevention Field Guide (2021) at 43 ("[f]or the purposes of fire prevention, single use overhead communications pole lines are generally not an ignition source because the energy within communications infrastructure is usually insufficient to ignite a fire."); AT&T Opening Brief (GRC) at 3 and 16, (stating about AT&T witness "Mr. Gallo explained that communications facilities placed on utility poles have low levels of electric current, and as such, "even while energized, [they have] no inherent potential to create a flame or electric arc."); Comcast Rebuttal Testimony (Slavin, GRC). Moreover, pole-mounted fiber optic communications facilities carry no electric current at all.

8 *See* Comcast-02 (Kravtin Opening Testimony) (GRC) at 4:20-22; 5:7-9; *Id.* at 5:14-6:2 ("This shift in resources harms the public interest by increasing the communications provider's costs of production, thus putting upward pressure on prices and complicating and distorting broadband investment and deployment decisions. ***This distortion has rippling effects throughout the economy*** into a wide range of areas from which consumers would derive significant economic benefit relating to broadband.") (emphasis added).

9 *See generally* D.23-11-069; Comcast Opening Comments (GRC) at 17.

10 *See* Attachment B to SDG&E WMP: https://www.sdge.com/sites/default/files/regulatory/2023-2025%20SDGE%20WMP%20with%20Attachments.pdf.

The Commission should ensure analysis of all wildfire mitigations includes evaluation of *all* quantifiable costs. When the benefit portion of a CBR equation is calculated to quantify a public benefit, such as the mitigation of wildfire risk, that public benefit should be weighed against public costs, including all the potential costs to the public. Otherwise, the calculation does not give sufficient weight to the costs portion of the equation and may result in artificially favorable CBR values.

Accordingly, when calculating CBRs for wildfire mitigation undergrounding projects, all the direct known and quantifiable costs of the proposed undergrounding must be included to properly value the CBR. Of course, one component of undergrounding cost is the cost of the undergrounding to the IOU, because that cost could be passed along to the public through an increase in electrical rates. For the same reason, the costs to other affected providers of public services should also be included in the equation.

If an undergrounding proposal includes undergrounding of communications facilities, the costs included in the CBR should include the costs of undergrounding communications facilities. To support this calculation, communications providers could provide IOUs estimates for undergrounding costs of particular portions of a project or standard industry costs for undergrounding communications facilities.

* * * * *

For the reasons set forth above, the Joint Responders respectfully request that the Commission require the IOUs to include all direct and quantifiable costs, including those imposed on communications providers, in any CBRs calculated for proposed underground mitigation projects.

Respectfully submitted,

*/ s/ David J. Miller*
David J. Miller
Assistant Vice President – Senior Legal Counsel, AT&T
*For the Joint Responders*[11]

[11] The signatory has been authorized to submit this response on behalf of all the Joint Responders.

Via Email
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November 12, 2024

Edwin Schmitt, Public Utilities Regulatory Analyst
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**Re: Questions for Stakeholders Regarding the CPUC SB-884 Guidelines**

Dear Mr. Schmitt:

The California Farm Bureau (Farm Bureau) appreciates the opportunity to provide comments on the additional questions for stakeholders presented on October 14, 2024.

**Introduction**

Farm Bureau represents agricultural energy customers that are located and take service from the state's electric investor-owned utility companies and has been active throughout the process from the legislature to now regarding SB 884. While the list of questions is lengthy and focuses on some areas which Farm Bureau does not typically engage in such as the Results of Operations (RO) models, the fundamental concerns about the enormous rate impacts this will have for *all* ratepayers permeates the discussion. Farm Bureau has repeatedly stressed that the SB 884 program is *voluntary* and the choice for a utility to engage in the process and receive expedited approval should include meaningful benefits to ratepayers and significant guardrails. If a utility deems the program too onerous, then the traditional General Rate Case (GRC) pathway can continue to be used. But ratepayers must know that utilities will be held accountable for the promises made of long-term savings and project costs with the burden for miscalculation favoring ratepayers. If a utility overestimates, ratepayers should receive a refund and if a utility underestimates, it should be the utility not ratepayers footing the bill for their delays or errors.

Farm Bureau does not attempt to answer every individual question and repeats many of the sentiments above, that in the instance of a "tie" the benefit must always go to the ratepayer. There is continued chatter about what can be done to lower rates, but unless the Public Utilities Commission (Commission or PUC) protects ratepayers by disallowing costs and requiring strict performance, those words will continue to ring hollow.

## A. Results of Operation (RO) Model

As stated above, Farm Bureau does not typically engage in the nuances associated with the individual utility RO models. However, from a 30,000 foot perspective, the disconnect between the Pacific Gas and Electric Company (PG&E)'s mini-RO model and the standalone RO model should not fall on stakeholders to reconcile and police. If the Commission chooses to allow PG&E to continue the use of this mini-RO model, the burden for questions 5 and 6 of provided sufficient information that the costs are not double counted and to provide a depreciation study should fall on PG&E. If PG&E chooses to continue to use the mini-RO model, it should then be incumbent upon them as the lone utility using this method to make abundantly clear the two models are integrated correctly and when questions are raised the ambiguity should favor ratepayers including the disallowance of said costs.

## B. Third Party Funding

2. Yes, given the extensive nature of these Applications and the various cost components, a separate advice letter that specifically addresses third party funding and how the cost caps are reduced should be required. This would seemingly be something the utilities should already be tracking and a worthwhile way to see whether even with third party funding, these projects were the most affordable way to reduce risk for ratepayers. The six month Progress Reports should contain some of the relevant information, but should any funding be received given that it is supposed to be applied to the cost cap for that specific year, an advice letter filing requirement should be triggered within 30 days of receipt or grant of the funds.

## C. CBRE Threshold

Yes, to parts a, b, and c. Utilities should be required to provide additional justification whenever an undergrounding project has lower Cost-Benefit-Ratios (CBRs) than expected because the justification for undertaking more expensive and longer duration undergrounding projects is that the cost and time is outweighed by the benefit. Anytime that this ratio is lower than 1.0 or is not a significant difference from alternative measures, it should trigger the utilities' need to provide additional justification as to why the projects are necessary. Again, the justification for undergrounding is that the benefits are significantly outweighed by the cost, but when that is no longer the case there should be a higher burden on the utility to justify why ratepayers should continue to pay the cost for this methodology other than that it provides the utility with a greater rate of return.

## D. Audit

1. Farm Bureau has found in other proceedings that utilities have argued the purpose of an audit is not to question whether the work was necessary or done correctly but rather that the cost being recorded were done so accurately and essentially that the numbers

add up. This clearly is not what is intended by the audit in this program, and it must be clear that a significant portion of the recorded costs are audited and not just a minimal sampling of the many number of costs that will be recorded in the designated period. Given the one way balancing account, the audit becomes a significant tool for protecting ratepayers and provides those stakeholders such as Farm Bureau, who do not have the resources to conduct a sufficient audit on our own, the ability to be insured that the costs being recorded are accurate and that the work that is being completed is being done properly and without waste. The accelerated nature of the program also does not provide for sufficient time for individuals to complete such work.

a. It must be made clear that the audit is not simply an exercise in ensuring that the utilities booked the cost into the correct sub accounts and that the numbers all add up, but rather that the audit is also reviewing utility performance and the reasonableness of the cost themselves. Language that supports the nature of the audit will eliminate misconceptions about the audit's purpose and value in arguing whether costs should be recovered.

b. Yes, the audit should verify that claimed utility activities and projects have been completed as claimed. Again, to the points above, without additional verification the limited ability for stakeholders to review and provide input means there will be little else for the Commission to rely on. It is unclear whether satellite imagery or photographic evidence would be sufficient, and other stakeholders may have a better methodology for use in verification but whatever method it will likely be valuable to future applications in the same area. The utilities have claimed the long lifetime of undergrounding as part of its value and photographic or image verification will provide a secondary benefit of a database of the condition in a certain area when future requests for maintenance or other changes arise.

c. Yes, the audit should address CBR claims. Again, not only would it be difficult but there likely will not be an opportunity for stakeholders to push back on any perceived claims of misalignment between CBR and the audit. Conducting a verification of utility claimed CBR versus actual CBR will provide the Commission with a significant tool to continue to determine whether undergrounding is in ratepayers' best interest.

5. Yes, at a minimum the SB-884 guidelines should be updated to include a timeline for when that true-up should occur. A true-up seemingly would be a sufficient method for addressing those refunds, but any refunds should be timely addressed and returned to ratepayers.

6. The audit at a minimum should verify how much funds were granted, when they were received, and how they were applied. Any claims of cost savings related to those funds should also be verified, once again, to ensure that even if third party funds are provided whether undergrounding remains the best methodology.

## F. Changes to a Utility's Expedited Underground Plan

In general, what has previously been suggested and Farm Bureau agrees with is that changes should come in the form of petitions for modification or a process by which scrutiny and repair involvement can be had. The ability for ratepayers to scrutinize changes at any point in the process is fundamental to ensuring that utilities are not gaming the system or misdirecting previously approved funds for one project into a modified project that stakeholders have not had the opportunity to comment on. Thus, the answer to all the questions in this section would be that anytime changes occur, those should be done by petition for modification and that stakeholders be given an opportunity to scrutinize and comment on those changes. There may be changes that are minor potentially from simple errors in transferring numbers or location information, names, etcetera. But even then, those changes could be addressed in a much shorter comment, rather than rubber stamped. Certainly, any change that will adjust CBR, cost, location, or timeline should undergo sufficient scrutiny given that these metrics are the bedrock for approval of these projects. Once they are adjusted the foundation for cost approval has changed and sufficient time should be given to evaluate whether they should be approved.

## H. Number of Alternatives

1. The PUC should not limit the alternatives to those required by OEIS and Farm Bureau along with other stakeholders shared significant concerns with the OEIS decision to limit alternatives. The purpose for undertaking the cost and time necessary to complete undergrounding projects is supposed to be because it provides the best CBR to ratepayers. If all alternatives or combinations thereof are not considered, then the exercise is futile. It should be the utilities' burden given the enormous costs that will be borne by ratepayers to prove undergrounding is the best choice.

2. A standard approach should be adopted for all projects, with the utilities being able to explain why a specific alternative may not be viable in a particular region. It should be simple enough for the utility to explain why a specific alternative was not considered or present the cost prohibitive information supporting why a specific alternative would not be viable in a certain region.

3. The PUC must establish a uniform way of comparing alternatives and the combination of those alternatives over distance and time but also could use a dollar amount as the metric. This way if the utility presents an undergrounding project with a certain cost cap, then the alternatives could be measured against the same cost cap and potentially provide significantly more miles of coverage for the same cost. This however ignores some of the benefits of faster deployment with other Alternatives. Either way, the PUC must ensure that to the best of their ability we are comparing apples to apples rather than allowing the system to be gamed in favor of undergrounding.

## I. Compliance with the Application

1. As stated above, the "tie" should go to the ratepayer. The utility should bear the brunt of a delay rather than collecting costs from ratepayers while failing to deliver a completed project. It should be incumbent on the utility to complete and energize a project prior to recovering costs for that project. This ensures that a project which may be on track with cost recovery that hits a delay has not already recovered a significant portion of costs and seemingly bind the PUC's hands for approving potential increased costs as part of a delay.

## J. How to Address Costs if an Application or Projects are Rejected or Abandoned

1. Undergrounding costs for projects that are not carried out or not completed should have a rebuttable presumption that costs are not recovered from ratepayers. Undergrounding is a costly endeavor, and utilities stand to gain significant financial incentives from undertaking undergrounding projects. One way to combat this perverse incentive is to put the burden on utilities for the cost to start these projects and limit recovery to only when a project has been completed. There may be extreme circumstances that warrant some level of recovery, but those instances should be rare and rarely result in recovery of all costs.

2. For parts a, b, and most certainly c, the answer does not change. Again, utilities should bear some of the risk in undertaking these projects and choosing why to use undergrounding versus other alternative methods. As for d, there is potential that an unforeseen circumstance with new legislation limiting the ability to complete a project warrants a utility to seek recovery for would costs incurred on a project that is now limited.

4. Yes and no, the PUC must make sure that requiring completion does not encourage a utility to simply start a project knowing there will be significant cost overrun but that a requirement for completion will force the PUC to approve costs for the project. However, if a utility has already undertaken a significant portion of a project, it would seemingly make little sense to completely abandon said project especially if ratepayers will be required to pay for the work that has already been done. Other non-utility stakeholders may have suggestions as to the completion threshold, but as stated above, the presumption should be for project issues to be borne by the utility absent an extremely compelling reason.

5. With regards to a, the Commission should absolutely adopt guidelines for cost recovery of abandoned projects to protect ratepayers. Certainly, projects that the utility unilaterally decides not to complete, or use should not recover costs from ratepayers. As for projects that are abandoned for other reasons, cost recovery should be limited and require a significant showing as to why the utility should make any recovery.

6. With regards to a, it is presumed there may be a variety of reasons why a project has remained at a particular stage for more than a certain period and other non-utility stakeholders may have a more appropriate timeline under sub b, but fundamentally utility decisions not to complete a project or to strand assets should result in the burden of those costs being borne by the utility. Utilities must bear some risk in this SB-884 framework otherwise there is no incentive not to push for undergrounding anywhere and everywhere knowing that if there are slowdowns or hiccups along the way costs will still be recovered.

7. The New Jersey rule covers the fundamental idea that utilities should have both the burden, and the risk associated with seeking accelerated levels of investment which is exactly what the SBA 884 program is trying to do. It would absolutely be useful for the PUC to develop a similar requirement and create a bright line rule that establishes when over recovery will be credited to customers and be clear the burden is on the utility to meet its deadlines and ensure that the costs that are being recovered are being put toward projects that are being completed on time.

**Conclusion**

Farm Bureau appreciates the opportunity to provide comments on these additional stakeholder questions and the considerations the Commission is making in ensuring money that is being extracted from ratepayers is being well spent. There must be some balance between the accelerated treatment utilities are seeking, the costs ratepayers will be required to pay, and the risks associated with the program. Given the current affordability crisis impacting *all* ratepayers and the dismal outlook for decreasing their acceleration, the utilities who seek to recover billions must bear the risk as the choice for choosing to take part in this *voluntary* program.

Sincerely,

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# PACIFIC GAS AND ELECTRIC COMPANY
## CPUC Safety Policy Division
## Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

**Requester: Schmitt, Edwin; Hanes, Fred**
**Request Date: October 14, 2024**
**Response Date: November 12, 2024**

**Introduction:**

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to respond to the questions provided by the Safety Policy Division (SPD) regarding California Public Utilities Commission's (CPUC or Commission) guidelines implementing Senate Bill (SB) 884. In these responses, PG&E refers to the two sets of SB 884 related guidelines:

(1) Attachment 1 to Resolution SPD-15 (CPUC Guidelines); and

(2) The Office of Energy Infrastructure Safety's (Energy Safety) Revised Draft 10-Year Electrical Undergrounding Plan (EUP) Guidelines dated September 13, 2024 (EUP Guidelines).

As a preliminary matter, PG&E notes that many of SPD's questions relate to issues that are already addressed in the CPUC Guidelines and/or the EUP Guidelines. We appreciate that in developing the SB 884 Program, both the CPUC and Energy Safety held multiple workshops and offered numerous opportunities for stakeholder input and comments on draft guidelines. The results of these efforts are reflected in the CPUC and EUP Guidelines, which provide robust processes and tools that allow regulators and stakeholders to review and evaluate the information provided by a large electrical corporation in support of its EUP. The CPUC Guidelines include audit provisions, costs caps, and requirements around unit-costs and cost-benefit ratios to closely monitor program costs and ensure compliant cost recovery. As the Commission explained in Resolution SPD-15, "[t]hese provisions of the Guidelines represent critical safeguards to ensure that rates associated with implementing SB 884 Program Plans are just and reasonable."[1] Given the extensive work and stakeholder inputs that have already gone into developing the CPUC Guidelines, PG&E does not support adding new requirements other than those that may help clarify existing requirements or more closely align the CPUC and EUP Guidelines, as needed.

1 Resolution SPD-15, p. 12

**<u>Questions and Responses to Questions:</u>**

## A. <u>Results of Operation (RO) Model</u>

**<u>Background:</u>**

The Commission requires IOUs seeking rate increases to reflect the results of their requests in what are called results of operation models ("RO models"). An RO model may illustrate rate impacts across all of the IOU's lines of business, such as in a General Rate Case (GRC), or it may model revenue impacts for a particular program in a "mini RO model." Both models present the utility's forecasted revenue requirement for its operations. The forecasted revenue requirement is calculated through a computer model called the RO model. The major components of the GRC RO model include:

- Rate Base
    - Includes information related to Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve;
- Return on Rate Base;
- Taxes;
- Other Operating Revenues and the Rate Base component.[2]

The Commission stated in Decision (D.) 00-07-050 that RO models should be user-friendly and facilitate the Commission's ability to quickly calculate the revenue requirement for various decision scenarios and should easily be able to accomplish the following:

- Change depreciation rates;
- Move unbundled cost categories (UCCs) between major functional groups (i.e., distribution, generation, etc.);
- Calculate the lead-lag portion of working cash;
- Calculate all taxes and tax depreciation;
- Make plant adjustments, including adjustments to beginning-of-year plant; and
- Calculate a distribution Revenue Requirement and Summary of Earnings.[3]

Standalone RO models are used to generate cost recovery requests in Applications to the Commission outside of General Rate Case (GRC) Proceedings. The Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) standalone RO model approach is completely integrated within their the main GRC RO model. SCE has used this integrated RO model approach to generate revenue requests in, for instance, a recent application to recover costs related to wildfire mitigation, vegetation management, catastrophic events, and wildfire liability insurance.[4] In the context of wildfire mitigation investments, SDG&E has not filed a standalone cost recovery application.

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2 For an example of how this is discussed in a GRC Decision see D.20-12-005 at 334-335.

3 *See* D.00-07-050 at 11.

4 A.24-04-005

PG&E utilizes what it calls a mini-RO model to generate revenue requests. This mini-RO model is distinct and separate from the main RO model that PG&E uses in its GRC Applications. In the context of wildfire mitigation investments, PG&E has used this mini-RO model approach in its 2023 cost recovery Application related to wildfire and gas safety.[5] Commission Staff understands that PG&E intends to use the mini-RO model approach to generate revenue requests for SB-884 Applications. According to PG&E, a mini-RO model is distinct from the RO models submitted to the GRC in the following ways:

- The standard mini-RO Model may be tailored for a separately funded/incremental rate case for specific types of costs and applicable income tax rules.
- The mini-RO Models used in separately funded/incremental proceedings cover a proposed revenue recovery period.
- All inputs and revenue requirement calculations are integrated within a single Excel model for simplicity and efficiency.[6]

**PG&E Corrections to Background:**

For clarification, PG&E proposes the following correction to the second sentence in the Background section:

> An RO model may illustrate <u>revenue requirements</u> across all of the IOU's lines of business, such as in a General Rate Case (GRC), or it may model revenue <u>requirements</u> ~~impacts~~ for a particular program in a "mini RO model."

**Question No. A-001:**

Should a standalone RO model be used for generating a revenue requirement for an SB-884 application, or is another approach more appropriate? How should each of the IOUs' approaches be harmonized to have one standard for ratemaking in this process? In your response, discuss the need to encourage transparency and stakeholder holder engagement to ensure that rate impacts are incremental to other funding granted to the IOU, accurately represented, and litigated in the process of generating a revenue requirement.

**Response to Question No. A-001:**

A standalone RO model (*i.e.*, mini-RO Model) should be used to generate revenue requirements for the SB-884 Application. A mini-RO Model is a standard standalone model that is used for all separately funded cases that are incremental to PG&E's GRCs. A standard mini-RO Model is tailored to address the requirements of a specific Application and to highlight the incrementality of costs above the baseline established in a GRC. The integrated RO Model, on the other hand, establishes a baseline revenue requirement calculated using the proposed cost forecast against which incrementality is measured. Both model types use a standard cost-of-service ratemaking formula. Additionally, the RO Model includes elements that are not applicable or relevant to a

5 A.23-06-008

6 PG&E response to data request EUP_DR_SPD_011_Q001-012 at 1-2

standalone Application, such as Administrative & General (A&G) expenses, common capital, depreciation study and working cash, among others. In order to transparently and readily identify incremental costs, the cost inputs to the separately funded/incremental Application's mini-RO model should be used for comparison against the GRC baseline costs. Using an application-specific Mini-RO Model will also benefit the Commission and stakeholders because the scope of the model will be focused on issues unique to the specific Application under review like the SB-884 Application.

The IOUs should each be able to use their own respective standalone RO Models to accommodate variations between the IOUs with regard to the SB-884 Application.[7] The IOUs should not be required to use a "one size fits all" approach, but instead should be able to propose a standalone RO Model that best addresses the unique aspects of that IOU's SB-884 Application.

Finally, with regard to transparency and incrementality, these issues can be readily addressed when using a standalone RO Model. For transparency, the IOU should explain in its SB-884 Application, the revenue requirement calculation that it intends to use so that the Commission and stakeholders can review and evaluate the IOU's proposed standalone RO Model. For incrementality, similar to other separately funded proceedings like the Wildfire Gas and Safety Costs (WGSC) Application, PG&E can include documentation to demonstrate incrementality when PG&E submits its SB-884 Application. PG&E's submission could show that the requested cost forecasts were not otherwise recovered in revenue requirements authorized in any other proceeding or any other cost-recovery mechanisms. As an example, in the WGSC Application[8], PG&E utilized four different methods to demonstrate that the costs in that application were incremental as follows: (1) analyzing 2020-2022 recorded costs for GRC base work to confirm we had utilized imputed adopted funding values in the 2020 GRC prior to seeking recovery of incremental costs in this proceeding, (2) demonstrating that PG&E hired new staff beyond what could be imputed from the 2020 GRC final decision, (3) ensuring costs were tracked in separate accounts, and/or (4) engaging an external auditor to assess and confirm that the costs in this application are incremental. A similar type of incrementality showing can be made in the SB-884 Application as well.

**Question No. A-002:**

Is the mini-RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

**Response to Question No. A-002:**

Yes. In addition to the explanation provided in response to Question A-001, PG&E recommends using the mini-RO Model approach for an SB-884 Application because:

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7 PG&E notes that the SPD questions use the terms "IOU" and "utility" interchangeably. In its responses, PG&E also uses the terms IOU and utility interchangeably, as well as the term "large electrical corporation" which is the term used in SB 884.

8 A.23-06-008, Exhibit (PG&E-1), Prepared Testimony, Chapter 15 Demonstration of Incrementality.

- The mini-RO Models are standard models that are used for separately funded/incremental rate cases and are tailored to the requirements of a specific Application, for specific types of costs (forecast/recorded or monthly/annual), and applicable income tax rules. The mini-RO Models use the standard cost-of-service ratemaking formula to compute revenue requirement.[9]

- To impute the capital revenue requirements, the mini-RO Models use adopted book depreciation rates and state and federal income tax rates from the GRC, as well as the adopted cost of capital from the Cost of Capital proceeding(s). Additionally, the mini-RO Model for separately funded/incremental Applications may include interest expense based on the applicable interest rates, timing of the decision and the approved cost recovery.

**Question No. A-003:**

Is the integrated RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

**Response to Question No. A-003:**

No, the integrated RO model approach is not appropriate for generating revenue requests in an SB-884 Application. As explained above in the response to Question A-001, the RO Model establishes a baseline revenue requirement calculated using the proposed cost forecast against which incrementality is measured. Using the RO Model in both the GRC and the SB-884 Application would create two separate baselines and would not highlight the incrementality of the SB-884 Application.

PG&E uses the mini-RO Model for all separately funded/incremental Applications.[10] The RO Model includes a comprehensive total GRC view that provides a Summary of Earnings compared to what was authorized from the last GRC Decision to the current GRC request. The features described below are specific to the GRC RO Model:

- Captures Administrative & General Expense by FERC Account, Resource Type, and Unbundled Cost Category (UCC).
- Captures Operations and Maintenance Expense for all Utility Functional Areas by FERC Account, Resource type, and Unbundled Cost Category (UCC).
- Performs Enterprise level detailed Income tax calculations.
- Includes proposed depreciation rates by Asset Class based on the GRC specific Depreciation Study.
- Includes proposed escalation rates by labor and non-labor component.
- Conducts detailed working cash computations.

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[9] *See* EUP_DR_SPD_011_Q002 (addressing mini-RO Model).

[10] *See* EUP_DR_SPD_011_Q001-012 (explaining use of mini-RO Model).

- The GRC RO Model generally covers a 4-year period, starting with the test year and does not produce life-of-asset revenue requirement calculations.
- Comprises multiple model files to handle various components.

While these features are necessary for a GRC proceeding, which addresses multiple functional areas and GRC-specific issues, these features are not necessary for a single application such as the SB-884 Application.

**Question No. A-004:**

Through data requests, PG&E has informed Commission Staff that PG&E's mini-RO model does not account for depreciation costs associated with topped poles.[11] These factors would be accounted for in PG&E's GRC RO model. According to PG&E, each of its GRC Applications includes a depreciation study which determines the depreciation rates and is the proper route to account for topped and retired poles. With the mini-RO model being distinct and separate from the main GRC RO model, what challenges might this create for ensuring that the depreciation costs of topped poles is properly accounted for within a utility's rate base? How should these challenges be addressed in the SB-884 Guidelines?

**Response to Question No. A-004:**

PG&E does not believe that using the mini-RO Model creates any challenges with depreciation. To the extent that existing assets, including topped poles, are replaced by the installation of underground assets, the poles would be retired in the GRC RO Model based on recorded and/or forecast data and no longer depreciated. In addition, the GRC depreciation study would include the effect of all recorded retirements through the base year as well as a consideration of future activity.

**Question No. A-005:**

Assume that a Commission Decision on a utility's SB-884 Application approves Project A to underground 1 mile of overhead (OH) line that is still in the utility's ratebase.[12] In a future GRC Application Proceeding, how would the Commission determine that the utility had appropriately removed the 1 mile of OH line from the ratebase if the SB-884 Application was based on the mini-RO model?

**Response to Question No. A-005:**

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[11] Topped poles refers to the process during an undergrounding project of cutting of the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried. See PG&E response to data request DRU14160_Case_EUP_DR_SPD_008, Question 1 at 1.

[12] A utility's rate base is the investment upon which the utility can earn its rate of return.

Please see the response to Question A-004. PG&E's GRC filing would include recorded retirements through the GRC base year and a forecast of retirements over the GRC cycle.

**Question No. A-006:**

PG&E has informed Commission Staff that it does not submit a depreciation study as testimony in an Application where the revenue request is generated by a mini-RO model. Should the Commission require a utility to submit a depreciation study along with an SB-884 Application? If so, should the utility be required to update certain parts of the depreciation study submitted with the utility's most recent GRC, such as that related to grid hardening and other wildfire mitigations? Explain your answer.

**Response to Question No. A-006:**

No, the Commission should not require a utility to submit a depreciation study along with an SB-884 Application. PG&E's depreciation study submitted in each GRC already takes into account considerations such as grid hardening and other wildfire mitigations in determining recommended depreciation lives and net salvage. These depreciation studies are comprehensive efforts and include consideration of the various causes of retirement of PG&E's assets. In addition, because the mini-RO Model would use only Commission adopted depreciation rates, it is not necessary to provide an additional depreciation study for the SB-884 Application.

## B. Third Party Funding

**Question No. B-001:**

How should the IOUs account for third-party funding they seek or receive, as required by Public Utilities Code Section 8388.5(j), for undergrounding projects to ensure the requirements of the Commission's SB-884 Guidelines and Senate Bill (SB) 884 are met?

a. How should ratepayer savings attributable to third party funding be accounted for?

    i. Should they appear as an offset to the proposed revenue requirement in a mini-RO model?

    ii. Should they appear in the IOU's next GRC?

    iii. Should there be a reporting requirement for the utilities to report on third-party funding? If so, what information should be included in this report?

b. Should the IOUs treat third-party funded plants as contributed plants? Why and why not?

c. Describe the IOUs' accounting for third-party funded plants in regards to utility plant accounts, and depreciation and amortization reserves.

**Response to Question No. B-001:**

PG&E has a designated team that manages the process to pursue non-ratepayer federal, state or other third-party funding opportunities for PG&E programs and projects. On a recurring basis, this team reviews federal, state and other investment programs for new funding opportunities. On a quarterly basis, PG&E files a report under Res.E-5254[13] that informs the CPUC of all IIJA, CHIPS and IRA-related applications we have submitted and their status. Rather than duplicating this reporting requirement for SB 884, the existing advice letter can be used to track and account for third-party funding sought and received by the Large Electrical Corporation that may be applicable to the EUP.

PG&E would be unable to reliably forecast which of its third-party funding applications will be successful or how much external funding it may receive in any given year. Thus, for ratemaking purposes, PG&E will need to evaluate the best method to refund to customers amounts received from third-party funding and will propose an efficient method to do this in its SB-884 Application.

Finally, PG&E notes that Generally Accepted Accounting Principles (GAAP) and the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) do not provide explicit rules or instructions for how companies should account for third-party funding such as government grants or loans. Like many other public companies, PG&E has referred to the International Financial Reporting Standards (IFRS) and their specific guidance under IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance* for accounting guidance related to governmental assistance.

**Question No. B-002:**

Should an IOU file an advice letter documenting which annual cost caps are reduced by third-party funding? If so, how often should it be filed and what should the advice letter include?

**Response to Question No. B-002:**

The CPUC Guidelines already require a utility to file an advice letter documenting which annual cost caps are reduced based on third-party funding received.[14] This advice letter should be filed annually given that it is intended to document an annual cost cap reduction. The advice letter should include the current annual cost cap, a description of the third-party funds that will be applied to the cost cap, and the adjusted annual cost cap.

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[13] Res. E-5254, Ordering Paragraph 5, requires a tier 1 advice letter providing quarterly reporting to Energy Division on the status of projects applied for or funded through the Infrastructure Investment and Jobs Act (IIJA), Clean Energy Infrastructure Grant Programs administered by the United States Department of Energy (DOE), the federal Inflation Reduction Act (IRA), and the federal Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS).

[14] *See* CPUC Guidelines at 11, Item 2.

## C. CBR Threshold

**Background:**

The Cost-Benefit Ratio (CBR) is described in D.24-05-064 and D.22-12-027 of Rulemaking (R.) 20-07-013. CBR is a financial metric used to evaluate the efficiency of a project by comparing the benefits it offers (in this case, wildfire risk reduction and reliability enhancement) to its associated costs (cost of undergrounding overhead lines). The greater a CBR is relative to 1.0, the more its benefits outweigh its costs. Thus, as an illustrative example, a project with a CBR of 7.0 has benefits that exceed its costs by seven times, whereas a project with a CBR of 1.0 means costs and benefits are equal, and a project with a CBR of less than 1.0 means that its costs exceed its benefits. If an IOU were allowed to deploy a project with a CBR less than 1.0, it could be due to operational constraints. For example, in order to complete a project, the IOU may be required to perform work on other circuits segments upstream or downstream from the circuit segment with a high CBR. Those upstream or downstream circuit segments may have low CBRs even though they are necessary to the project, and therefore they may bring down the total CBR of a project. Sometimes projects with a CBR of 1.0 or below would be proposed because they are associated with high-risk overhead lines that face constraints such as operational considerations or legal statutes.[15]

**Question No. C-001:**

Should IOUs be required to provide additional justifications when they want to install projects that have either:

a. Low CBRs[16] (in comparison to other UG projects in that IOU's application);

b. CBRs below 1.0; or

c. Lower CBRs compared to the CBRs of alternative wildfire mitigations that do not include undergrounding (such as covered conductor, remote fault detection technologies or high impedance fault detection)?

    i. And in each case (for Questions (1) (a)-(c) above) where the answer is yes, please explain why and what those additional justifications might be.

    ii. Furthermore, if the 1.0 threshold referenced in question (1)(b) above is too low from your perspective, and if IOUs should therefore be required to provide

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15 Associated circuit segments refer to the high-risk circuit segments which might be the primary reason to hardening the Low CBR circuit in the first place.

16 "Low CBR" can be defined as projects whose CBRs are below a certain threshold (e.g., 2 standard deviations, where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average CBRs of other projects offering the same type of mitigation.

additional justifications when they want to install projects that have CBR thresholds greater than 1.0, then at what threshold above 1.0 should the additional justifications no longer be necessary and why?

**Response to Question No. C-001:**

PG&E's EUP will explain how we use CBRs for decision-making, including for the scenarios described below (a-c). Additional justification beyond what is required in the EUP is not necessary.

a. No additional justification above what is required in the EUP is needed. The EUP requires an explanation of how it will use the CBR in decision making for selecting work for undergrounding.[17] CBRs are only one factor of decision making along with the Key Decision-Making Metrics (KDMMs) that PG&E will rely on when choosing mitigations and should not disproportionately influence project prioritization. For example, projects with lower CBRs may be prioritized in extremely high-risk locations or in fire rebuild areas where we need to expedite service restoration.

b. No additional justification above what is required in the EUP is needed. There are quantitative and qualitative factors that are incorporated into a decision whether to underground a project. PG&E uses a comprehensive decision tree that determines whether there are additional factors that make undergrounding the appropriate the mitigation type for that location. Examples of qualitative factors include Public Safety Specialist feedback, tree strike risk, ingress and egress. However, it is expected that undergrounding a project with a CBR less than 1.0 would not be a common scenario and would require additional justification including the description of the specific circumstances and conditions that were considered in making the decision to underground.

c. No additional justification above what is required in the EUP is needed. The EUP allows the Large Electrical Corporations to justify project selection using metrics other than CBR.[18] For example, based on the requirements in the EUP Guidelines to meet a mitigation threshold, PG&E may pursue undergrounding over an alternative mitigation because undergrounding is the only solution to reach the mitigation threshold.[19] There may be constructability and feasibility constraints that limit the ability to execute mitigation alternatives.

   i. N/A - The answer to questions (a) – (c) are no.

   ii. It is unnecessary to set an arbitrary CBR value and no justification for selecting a mitigation alternative is needed if the CBR for the alternative mitigation is above or below the arbitrary CBR. The requirements in the EUP Guidelines describe the scenarios where additional justification is required (e.g. when a project does not meet

[17] EUP Guidelines, Section 2.4.4.
[18] EUP Guidelines, Section 2.7.3.
[19] EUP Guidelines, Section 2.7.9.2.

the project-level risk threshold).[20] A decision tree will be established in Screen 3 of the Project Acceptance Framework for the EUP which will explain why a project is selected for undergrounding for reasons not captured in the CBR calculations (e.g. tree strike risk or ingress/egress). Both the EUP requirements and CPUC requirements will ensure that cost-effectiveness is a key metric for decision making.

## D. Audit

**Background:**

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain conditions (Phase 2 Conditions) in order for Commission to authorize the recovery of those costs via a one-way balancing account.[21] That one-way balancing account is subject to audit. If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. The details of this audit, including who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order.

**Question No. D-001:**

Please expand on what the main objectives of the audit should be, in addition to ensuring the Phase 2 Conditions have been met?

a. What language will best ensure that the audit achieves its various goals, including determining whether the costs booked to the balancing account meet the Phase 2 Conditions?

b. Are the specific conditions and other criteria for the audit clearly outlined in the Commission's SB-884 Guidelines to help determine whether costs in question meet such criteria?

c. Should audit objectives include verifying that claimed IOU activities and projects have been completed as claimed?

    i. Would satellite imagery or other photographic evidence be sufficient to perform this verification?

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[20] EUP Guidelines, Section 2.7.9.2.

[21] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

d. What are the project characteristics (e.g. projects with low CBR) that the audit should address?

   i. Should the CBR stated in the Application be verified during the audit?

e. Should the auditor be required to follow professional auditing standards to meet the audit objectives; and if so, which ones?

**<u>Response to Question No. D-001:</u>**

The main objective of the audit should be that the "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.)."[22]

a. For the audit to achieve its objective, the auditors should be provided with the Phase 2 Decision, should establish compliance criteria based on that decision, and then should perform a statistically appropriate level of sampling to confirm that the costs are properly recorded to the one-way balancing account.

b. Resolution SPD-15 was clear that the scope of the audit should focus on the conditions established in a Phase 2 Decision. While the auditors may refer to Resolution SPD-15 and other materials to provide background, the focus of the audit should be on compliance with the Phase 2 Decision.

c. No. The Commission was clear that the purpose of the audit is to review "costs booked to the one-way balancing account . . .." [23] Under SB 884, there is a separate, independent monitor process that evaluates implementation of the EUP.[24] Based on the Independent Monitor's evaluation and report, OEIS will assess the large electrical corporation's compliance with the plan and may recommend penalties to the Commission. The auditor retained by the CPUC to audit costs should not replicate or duplicate the Independent Monitor's work.

d. The audit should not evaluate project characteristics. Instead, as the Commission specified, the audit should focus on costs recorded in the one-way balancing account and whether these costs meet the conditions specified in a Phase 2 Decision.

e. The auditor should be required to meet professional auditor standards. The specific standards that should be applied are the American Institute of Certified Public Accountants (AICPA) Consulting Standards. The AICPA Standards are the appropriate for the following reasons:

   1. Flexibility: The AICPA Consulting Standards provide auditors with greater flexibility in addressing areas of concern. The standards allow for professional judgment in determining the appropriate procedures and methodologies to assess

22 Resolution SPD-15 at 5.
23 Resolution SPD-15 at 5.
24 Cal. Pub. Util Code § 8388.5(g).

recovery of costs through a one-way balancing account. This flexibility permits a customizable evaluation and approach based on the unique circumstances of the program and account.

2. Applicability to Commercial Entities: Compared to another standard, GAGAS (Generally Accepted Government Auditing Standards), which primarily focuses on government entities, the AICPA Consulting Standards are specifically designed for commercial entities like PG&E. Utilizing standards tailored to the nature of the program can help ensure the evaluation is conducted in a manner that aligns with industry practices and the specific needs of the organization, program, and conditions.

3. Comprehensive Guidance: The AICPA Consulting Standards provide comprehensive guidance for performing consulting engagements. They encompass a range of considerations, including independence, objectivity, competency, and due professional care. By adhering to these standards, the CPUC and stakeholders can be ensured that an evaluation will be conducted in accordance with recognized professional practices.

**<u>Question No. D-002:</u>**

In D.23-02-017, the Commission explained that costs are incremental if "in addition to completing the planned work that underlies the authorized costs, the utility had to procure additional resources, be they in labor or materials, to complete the new activity. The existence and completion of a new activity by itself does not prove the cost was incremental."[25]

a. With this Decision in mind, how should the Guidelines ensure that the scope of the audit addresses whether the costs in an SB-884 Application are incremental to other revenue requests presented to the Commission in a GRC or other cost recovery application? Please provide suggested language.

b. Should an IOU be required to present costs related to straight time labor, overtime labor, contracted labor or other labor-related costs in its showing of incrementality in an SB-884 Application?

c. Should audit Guidelines address the issue of incrementality between the Balancing Account and Memo Account authorized in Resolution SPD-15 and established through a utility's SB-884 Application? If so, what language would you recommend?

d. Should an IOU be required to document its methodology of tracking incremental costs?

    i. Should all IOUs be required to use consistent methodologies in tracking these incremental costs?

[25] 23-02-017 at 27.

ii. Should and IOU be required to document how the GRC-approved cost categories line up with account categories or projects claimed to provide support for its methodology of tracking incremental costs?

**<u>Response to Question No. D-002:</u>**

a. In D.23-02-017, the Commission described an audit performed by Ernst & Young to determine whether costs that PG&E was requesting in that proceeding were "incremental in nature."[26] Given the Commission's reliance, in part, on the Ernst & Young audit in approving the settlement at issue in D.23-02-017, PG&E suggests that the Ernst & Young audit in that proceeding be used as an example of the scope of the audit for SB-884 Applications.[27]

b. Yes.

c. PG&E believes that Commission precedent and decisions describing incrementality are relatively clear and that nothing needs to be added to the CPUC Guidelines to define "incrementality." Moreover, the Commission's guidance on incrementality may change over time. Rather than needing to constantly update the CPUC Guidelines based on the most recent CPUC decisions or regulations, PG&E recommends that the CPUC Guidelines simply state that the utility is required to address incrementality "based on current Commission precedent and/or regulations."

d. Each IOU should document the methodology it uses for tracking incremental costs.

   i. The IOUs should not necessarily be required to use consistent methodologies for tracking incremental costs. While the IOUs will likely use similar methodologies, there may be reasons why one IOU needs to use a slightly different methodology or approach (*e.g.*, accounting software, overall approach to cost tracking, etc.). The IOUs should explain their methodology but should not be required to use a uniform methodology. In addition, developing a uniform methodology would likely require substantial time and resources from all of the IOUs, stakeholders, and the Commission. It is also important to note that submitting SB-884 Applications is optional and some of the IOUs may choose not to submit an application; thus, requiring the IOUs to develop a single, consistent methodology would be unnecessary.

   ii. Each IOU should describe their respective methodology for tracking incremental costs. Requiring an IOU to line-up GRC categories and costs may not be necessary. Rather than establishing a single methodology in advance, the

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[26] D.23-02-017 at 25.

[27] The Ernst & Young audit referenced in D.23-02-017 was included with PG&E's prepared testimony in our 2020 Wildfire Mitigation and Catastrophic Events (WMCE) proceeding (A.20-09-019, filed September 30, 2020). The Ernst & Young report is Attachment A to Chapter 8, Demonstration of Incrementality.

Commission should allow the IOUs to present their respective methodologies for review and evaluation by the Commission and stakeholders.

**Question No. D-003:**

When should the audit of the balancing account occur?

a. Should the audit begin after the Commission adopts a Decision in the utility's GRC Application proceeding; if so, when?

**Response to Question No. D-003:**

The EUP is intended to be a 10-year program. The dates and frequency of the audit must balance the benefit of an audit with the workload, resources and costs impacted by an audit. PG&E recommends that an audit occur three times during the 10-year program. The first audit would occur three years after the EUP program commences. This would allow sufficient time for the program to be implemented and materials to audit but would also allow for corrections by the utility early in the 10-year program if the audit findings indicated that the utility needed to make any changes in its accounting or record-keeping.

The second audit would occur after the sixth year of the EUP program. This would be a little more than half of the program life and would allow the auditors to confirm that the utility implemented any necessary changes or recommendations.

Finally, a third audit would occur after the 10th year of the EUP program. This would be the final audit of program costs.

**Question No. D-004:**

How often should the audit of the balancing account occur?

a. Should an audit of the balancing account be limited to once every four years to correspond with the GRC cycle?

b. If an audit of the balancing account should occur multiple times in a GRC cycle, explain how many times and the rationale for requiring multiple audits within a utility's GRC cycle?

**Response to Question No. D-004:**

*See* PG&E's response to Question D-003.

**Question No. D-005:**

The Commission's SB-884 Guidelines state that if the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund to ratepayers.

a. Should language be added to the SB-884 Guidelines that explicitly describes the method for a refund, such as a true-up in the utility's rates after the audit has been completed? If yes, provide suggested language along with a justification. If no, explain why.

**Response to Question No. D-005:**

For clarification, Resolution SPD-15 states that "[i]f an audit finds 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."[28] This language makes two principles clear. First, the Commission is not bound by the conclusions of an audit. Instead, the Commission reviews the audit and makes its own determination as to whether the Phase 2 Conditions were met. Second, costs that do not meet the Phase 2 Conditions "may" be subject to refund. In reviewing a specific situation, the Commission can and will exercise its independent authority to determine if refunds are appropriate or not if Phase 2 Conditions have not been met.

With these principles in mind, PG&E believes that the CPUC Guidelines should not include language describing the specific method of refund. In any given situation, the Commission may determine that refunds are or are not appropriate and the Commission may also tailor a refund mechanism to the specific circumstances at issue. Rather than trying to predict the potential scenario that will lead to an outcome and including prescriptive, limiting and potentially inapplicable refund requirements, the CPUC Guidelines should leave to the Commission the opportunity to evaluate a specific circumstance and decide on the appropriate refund mechanism, if any.

**Question No. D-006:**

The Commission's SB-884 Guidelines require the utility to identify any wildfire mitigation cost savings in its Application.[29] How should the claim of cost savings be addressed by the audit?

**Response to Question No. D-006:**

For clarification, the CPUC Guidelines provide:

> 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

[28] Resolution SPD-15 at 2.
[29] For details see SPD-15, SB-884 Program: CPUC Guidelines at 7.

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.

i. 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.

ii. 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.

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.[30]

There are several problems with a proposal to audit the forecasted wildfire mitigation cost savings. Nothing in Resolution SPD-15 or the CPUC Guidelines requires an audit for forecasted cost savings. Rather, Resolution SPD-15 clearly defines and limits the audit scope to "costs recorded in the one-way balancing account."[31] Thus, an audit of forecasted wildfire mitigation plan savings is not within the audit scope envisioned by the Commission in Resolution SPD-15 and should not be added for the following reasons.

First, as the CPUC Guidelines make clear, potential wildfire mitigation cost savings are simply a forecast. The utility is required to provide "forecasted wildfire mitigation costs" that will be reduced by the EUP. However, these forecasts are not binding, nor an EUP compliance requirement. And for good reason. Forecasts, especially over a 10-year period, are subject to subsequent events and unanticipated circumstances that may significantly change the actual results. Given this potential variability, auditing a forecast would have little value.

Additionally, the CPUC Guidelines require a utility to "explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers." Once the methodology is approved, this is something the utility can report on over the course of the 10-year EUP. However, there is no indication in the CPUC Guidelines that forecasted savings will be subject to an audit, nor should a new requirement be imposed given the substantial resource requirements and costs associated with an audit.

**Question No. D-007:**

Should the Commission consider other possible audits completed previously by either third parties or internal IOU auditors as part of the assessment in determining appropriateness and reasonableness of claimed costs in question?

30 CPUC Guidelines at 7-8.
31 Resolution SPD-15 at 2.

**Response to Question No. D-007:**

*See* PG&E’s response to Question D-006.

## E. Net Present Value (NPV) Calculations and Sensitivity Analyses

**Background:**

**NPV Costs and Revenue Requirement**

Because undergrounding projects take a long time to complete and have long useful lives, their CBRs are calculated in present day dollars, even if the cost will be much higher in the future. This calculation is called the NPV of costs from the revenue requirement and involves discounting future revenue requirements (which represent the utility's future costs) to their present value. Utilities need to identify and report the future revenue requirements: these are the yearly costs the utility expects to recover from ratepayers, typically including operational expenses, capital expenditures, and a return on investment. Utilities need to determine and report the discount rate(s) representing the time value of money and how NPV costs are calculated.

**Sensitivity Analyses**

A sensitivity analysis is a technique used to understand how different inputs into a model impact the outcome or results. For example, sensitivity analysis is often used in arriving at a CBR and shows how sensitive the projected costs, benefits or risks are to changes in the input assumptions.

**AB 2847**

Assembly Bill (AB) 2847 (Stats. 2024, Ch. 578) requires the following:

> Pub. Util. Code Section 739.15(a) The commission shall determine in a scoping ruling or other ruling whether an application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures requires the estimates described in subdivision (b).
>
> (b) An application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures, including an application for conditional approval of the costs of an undergrounding plan pursuant to Section 8388.5, shall include, if the commission pursuant to subdivision (a) determines that the estimates are required, the electrical corporation’s or gas corporation’s best estimate of both of the following:
>
>> (1) The application’s impact on the electrical corporation’s or gas corporation’s annual revenue requirement for each year that the capital expenditures described in the application are expected to remain in the application’s rate base if the application is approved or conditionally approved.

> (2) The net present value of the application's impact on the electrical corporation's or gas corporation's annual revenue requirement provided pursuant to paragraph (1).
>
> (c) The commission shall require the electrical corporation or gas corporation to provide supporting workpapers and calculations for the estimates described in subdivision (b).[32]

**Question No. E-001:**

In the context of AB 2847, should the utilities calculate and report their revenue requirement and NPVs costs in an SB-884 Application using a consistent method across IOUs? Explain your answer.

**Response to Question No. E-001:**

No, utilities should not be required to calculate and report their revenue requirement and NPV costs in an SB-884 Application using a consistent method across IOUs. To avoid increased administrative burden for both IOU and Commission staff, the IOUs should be able to use existing systems and processes that have been used for previous regulatory filings for calculations and reporting. Commission Staff works closely with the IOUs and have individuals with in-depth knowledge of each IOU's processes and RO Models. It is unnecessary to require the IOUs to develop new methods to be consistent with one another and to then require Commission staff to relearn complicated processes and tools. Thus, PG&E recommends that each IOU use the same process for calculating and reporting revenue requirement and costs that they it uses in their CPUC-Jurisdictional Applications.

**Question No. E-002:**

Considering the D.24-05-064 requirement that the IOUs present the results of three discount rate scenarios for their CBR calculation,[33] should the utilities be required to present NPV Benefits, NPV Costs, and CBR using each of the three discount rates in their SB-884 Applications?

**Response to Question No. E-002:**

Yes, when calculating CBRs, utilities should calculate and present NPV Benefits, NPV Costs, and CBR using each of the three discount rates in their SB-884 Applications.

Utilities should also be allowed to calculate and present NPV Benefits, NPV Costs, and CBR using a climate adjusted discount rate. D.25-05-064 allows the California IOUs to quantitatively

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32 https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB2847

33 See D.24-05-064 at 102-105. The utilities are required to calculate CBR for each mitigation using three discount rate scenarios: a) Societal Discount Rate Scenario, b) Weighted-Average Cost of Capital Discount Rate Scenario, and c) Hybrid Discount Rate Scenario.

consider climate change impacts in their RAMP filings. It is important for each utility to remain consistent among its other regulatory filings.

**<u>Question No. E-003:</u>**

Given that different mitigation projects may start at different times and become used and useful[34] in different years, how should the utility incorporate these differing timeframes into the calculation of NPV Costs and NPV Benefits?

**<u>Response to Question No. E-003:</u>**

Given that NPV calculations are from the perspective of ratepayers as opposed to the utility, the calculation of NPV Costs and NPV Benefits should be based on costs and benefits associated with only those mitigation projects that have already become used and useful by a given calculation year. To the extent that a mitigation project becomes used and useful later in time, that project will have a smaller impact on NPV calculations - all else equal - as a result of discounting back to present value.

**<u>Question No. E-004:</u>**

Should the Commission require IOUs to report and compare NPV Costs and NPV Benefits, and CBR of undergrounding in a consistent manner across IOUs?

a. Do the current Commission SB-884 Guidelines allow for consistent comparison between undergrounding projects and alternatives? If yes, explain why. If not, why not?

b. Do the current Commission Guidelines allow for accurate comparison between undergrounding projects and alternatives? Explain your answer.

**<u>Response to Question No. E-004:</u>**

No, the Commission should not require IOUs to report and compare NPV Costs and NPV Benefits, and CBR of undergrounding in a consistent manner across IOUs. The Commission can compare total NPV costs and NPV benefits for mitigation alternatives but should not require the IOUs to organize or categorize costs and benefits in a consistent manner. Each IOU uses its own systems for recording, managing and reporting costs and should not be required to conform to a system that may not align to how it has historically tracked, managed, and reported its costs. Requiring this type of alignment would introduce time and additional costs into the process.

a. Yes, the CPUC Guidelines allow for a consistent comparison among undergrounding projects and alternatives. They require information on forecast CBRs for each alternative wildfire mitigation method across all projects. The Commission requirements are

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[34] The used and useful year of a project is the year that the project is completed and energized.

consistent with Public Utilities Code § 8388.5(c)(4) stating that an undergrounding plan must include comparisons between undergrounding and alternative above-ground mitigations and that the large electrical corporation should all use reasonable and comparable assumptions in its calculations of forecasted CBRs for both undergrounding and each alternative wildfire mitigation method considered.

b. Yes, the CPUC Guidelines allow for an accurate comparison between undergrounding projects and alternatives. Costs recorded to the balancing account are subject to audit and costs recorded to the memorandum account are subject to reasonableness review. The audit provision in the CPUC Guidelines and the reasonableness review process allows the Commission to confirm that the cost and benefit information provided by a utility is accurate.

## F. <u>Changes to a Utility's Expedited Undergrounding Plan</u>

**<u>Background:</u>**

OEIS' revised Electrical Undergrounding Plan (EUP) guidelines allow for changes to the IOU's undergrounding Plans to occur throughout the ten year time period of any particular Plan. For example, Guideline 2.7.5.2 provides that model version changes are "qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a backtest report (see Section 2.7.6 )." OEIS defines "calibration changes" as "smaller changes that do not significantly impact the Model Risk Landscape and only require the establishment of a new Baseline."[35] In Section 2.4.2.4 of the OEIS Guidelines, a Confirmed Project is defined by the boundaries of the Confirmed Project Polygon that encompasses the entire Circuit Segment on which the Undergrounding Project is defined.[36] If an IOU changes its project, the polygon (or other illustration of where and how the undergrounding project will occur) is not updated. However, the OEIS Guidelines in Section 2.3.4 also state that if the scope of a project changes to include sections outside of the Confirmed Project Polygon (e.g., if a portion of another Circuit Segment outside of the approved Confirmed Project Polygon is added to a project), the utility can calculate risk reduction by using the risk reduction for "the full (expanded) project" for determining the contribution towards the Plan Mitigation Objective, and yet the utility may only use "the work inside the original Confirmed Project Polygon" for determining whether the project meets the Project-Level Standard. Hence, cost and risk reduction calculations, that will provide the substantial factual basis from which the Commission will deliberate on to make its Phase 2 Decision, may be impacted by potential changes to the scope of projects after a Phase 2 Decision is issued.

[35] See OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.5.2 at 36.

[36] OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

**<u>Question No. F-001:</u>**

How should the Commission ensure and evaluate that the costs, risk reduction, and CBR of a project are accurately calculated when portions of Circuit Segments are added or modified after:

a. an IOU submits an SB-884 Application to the CPUC?

    i. If an IOU changes its projects after obtaining OEIS approval of its EUP, how should the utility incorporate these changes in its Application for cost recovery at the CPUC?

b. the CPUC adopts a Phase 2 Decision on an SB-884 Application?

    i. If an IOU changes a project after the adoption of a Phase 2 Decision, for example due to circuit expansion, risk model change, or operational constraints, how should any additional costs, or cost reductions, be accounted for? Explain your answer.

    ii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC require an IOU to report changes to the project's CBRs? Should there be a threshold over which CBR changes should be reported?

    iii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC address projects that no longer meet the conditional approval stipulated in the Phase 2 Decision?

c. an audit of the SB-884 Application has concluded?

d. an IOU submits an Application for a just and reasonableness review of its SB-884 Memorandum Account?

**<u>Response to Question No. F-001:</u>**

As an initial matter, it is important to provide an overview of the EUP process. Energy Safety will approve a Project Acceptance Framework that the utility will use to create the list of undergrounding projects throughout the 10-year EUP period. The utility will submit a portfolio containing a minimum of 25 individual undergrounding projects (i.e., circuit segments) at the time it submits an EUP and will incorporate additional projects into the EUP over time in progress reports at six-month intervals. In accordance with the Draft EUP Guidelines, the utility must submit an updated Progress Report 0 every six months during the period the EUP is evaluated by Energy Safety and the CPUC.[37] The utility will submit its cost recovery application within 11 months of its EUP being approved by Energy Safety (assuming 9 months for EUP approval and 60 days for filing the application with the CPUC). Thus, at the time a utility submits its SB-884 Application, the EUP will include its first tranche of undergrounding projects

[37] OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.6 at 23.

(a minimum of 25) that was included with the EUP and a second tranche that it will have submitted in the first six-month report.

For a circuit segment or portion of a circuit segment, the utility will evaluate each eligible circuit segment (as defined in Appendix A of the EUP Guidelines) and determine whether the circuit segment (defined as a “project”) or certain portions of the circuit segment (defined as a “subproject”) are eligible for undergrounding. Each project and subproject that is added to the EUP will be included in tranches of work that are incorporated into the EUP over time. PG&E’s EUP will map to the circuit segment that is represented in our risk model. Circuit segments will only be modified after a risk model change. Updates to the risk model and circuit segments would result in new projects, not modifications to existing ones.

Given the nature of an undergrounding project, certain changes can and often do occur during project construction. For example, during construction it may be necessary to modify the planned route of an undergrounding project. This modification would change the amount of primary distribution line that is undergrounded and would be reflected in the recorded project costs. While the forecast CBR and risk reduction were based on the planned project route, the actual CBR and risk reduction would reflect the final project route. With this background in mind, PG&E provides the following responses to Question F-001:

a.i An IOU will submit its SB-884 Application to the CPUC only after its EUP is approved by Energy Safety.[38] As discussed above, the utility will regularly update its list of projects every six months.

The CPUC Guidelines require the utility to provide the information listed in CPUC Guidelines Appendix 1 for each project included in the EUP Plan and Application. As projects are added to the portfolio (the EUP Plan), the utility will update its list of projects and submit Appendix 1 information for each new project to the CPUC as part of its regular progress reporting.

b.i The process for updating a list of projects after adoption of a Phase 2 Decision should be the same as described in response to Question F-001(a)(i) above. The utility’s 6-month progress report should include the list of all projects in a utility’s portfolio. Once a project has passed through Screen 3, it is a Confirmed Project (EUP Guidelines, Section 2.4.5). By the time a project passes Screen 3, PG&E will have already considered circuit expansions, risk model changes and operational constraints. While there could be cost changes due to modification of a circuit segment or operational constraints (discussed in response to Question F-001(a) above), there will not be cost changes due to risk model changes.

b.ii As described in response to Question F-001(a)(i), a utility may modify a project after the adoption of a Phase 2 Decision. The utility will submit an annual CBR threshold to the Commission that will be evaluated based on the two-year average recorded CBRs

[38] Cal. Pub. Util. Code §8388.5(e).

for a plan year and the prior year.[39] The utility will only report recorded CBRs for individual projects which will already reflect project changes.

While PG&E does not think there is a need for a utility to regularly report changes to a project's estimated CBR to the Commission, we recognize that there could be instances where it would be necessary. For example, if a utility asked to update an annual CBR threshold through a change order process, it would be reasonable to update the forecast CBRs for the projects that support the updated annual CBR.

b.iii The CPUC Guidelines state that during Phase 3, the Commission will review any applications for recovery of costs recorded in the memorandum account (*i.e.*, any costs that do not meet the Phase 2 Conditions) to determine whether those costs were just, reasonable, and incremental to any other costs approved by the Commission.[40] We support this provision.

c. A utility is required to report total recorded costs to date[41] and will update its recorded costs with every 6-month report. If a project changed, the utility would report the change in costs in the next progress report. It is unlikely that a utility would need to go back and update costs already provided to the CPUC because the change in costs would be reflected in the next progress report. Therefore, it is unlikely that there would be a need to change recorded costs for a project that changed after an audit of the SB-884 Application concluded. To the extent that were necessary, the utility would alert the CPUC of the change and, if directed by the CPUC, would submit the updated cost information for review by the auditor.

d. A utility determines when to file an application for costs recorded to its SB-884 Memorandum Account. If a project changes after a utility files an application to recover costs recorded to the Memorandum Account, and the project change results in a change to the recorded costs, the utility can either update its application or request review of the recorded costs that have changed in a subsequent application.

**<u>Question No. F-002:</u>**

Considering the implications of OEIS Guidelines Section 2.3.4 described above, when the utility calculates CBRs, should the utility use the NPV Benefits calculated for the risk reduction from:

a. "the full (expanded) project"? Why or why not?

b. "the work inside the original Confirmed Project Polygon"? Why or why not?

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[39] Resolution SPD-15 at 9, Item 6.
[40] CPUC Guidelines at 4.
[41] CPUC Guidelines at 13, Item 1.

c. Would your answers to 2a. and 2b. depend on circumstances, such as when the CBR is calculated? Please describe the circumstance and explain why it would affect the answer to 2a. and 2b.

**Response to Question No. F-002:**

The NPV Benefits calculated for the full expanded project and the work inside the original confirmed polygon are calculated at different points in the project lifecycle.

a. Benefits should be calculated for the full expanded project in Screen 2 to be able to do a comparable assessment and to calculate the CBR. Full expanded project scope is an output of Screen 3, and the Guidelines require "...once the project has completed its scoping phase, the Screen 2 comparison must be updated to reflect the scoped project." For example, if a project is amended to include portions of neighboring CPZs to the project scope, using the full expanded project would provide the best estimate of NPV benefit and CBR, as project fixed costs would be spread over the full scope of the project.

b. It is unlikely that many projects will expand beyond their CPZs and require that a new "full (expanded) project" be considered. Therefore, the final confirmed project polygon will be adequate for estimating CBRs, once the scoping process in Screen 3 has been completed, in the majority of cases. Similar to part (a), any changes to scope in this phase will require that CBR be updated to reflect the project as scoped. A final CBR and NPV of Benefits would be calculated after project completion and used for cost recovery purposes. The risk within a polygon could change between scoping and project completion. Any CBR or NPV calculated before project completion would be based on assumptions only.

c. When a project expands beyond a given CPZ and incorporates portions of neighboring circuit segments, it is necessary to calculate CBR using the full project scope, so that the project's benefits and costs are most accurately represented. For example, if a CPZ neighbors a very small high-risk circuit segment, it would make sense to combine the scope of these projects, as they will be most efficiently executed together, where some fixed costs can be shared. Calculating the cost and benefits accordingly, would provide the most accurate representation of CBR. If a project is not expanded in this way, using the final confirmed project polygon is adequate to calculate CBR.

**Question No. F-003:**

There are limits on Commission staff's ability to make changes to a Commission Decision or Resolution pursuant to delegated authority. D.02-02-049 and GO 96-B Rule 7.6.1 describe the difference between discretionary and ministerial action.[42]

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[42] While discretionary and ministerial actions vary based on the subject matter, they broadly mean the following. Ministerial actions are actions which are made based on pre-defined criteria. These actions

a. If an IOU seeks to change an undergrounding project, is there any change that you believe could be deemed ministerial with approval delegated to staff? If so, describe such ministerial changes.

b. If an IOU seeks to change an undergrounding project is it your view that a Petition for Modification (PFM) is required?[43] Does your answer depend on the type of change? If so, please explain.

<u>**Response to Question No. F-003:**</u>

a. PG&E envisions three possible types of ministerial project changes that we describe below. None of these types of changes would require changes to a Commission Decision or Resolution:

<u>Project Change 1</u>: As discussed in response to Question F-001(a), a utility will be adding projects to its portfolio throughout the life of the 10-year undergrounding program and may make certain changes to projects during project construction (*e.g.*, the utility may adjust the route of a project in response to local conditions). Adding projects to the portfolio or making changes during construction will not require any type of change with regards to cost recovery because: (1) a utility will update its list of projects in its regular progress reports (see response Question F-001(a)(i)); and (2) a utility will report recorded costs and CBRs in its cost recovery progress reports which will incorporate changes that occurred during construction (see response Question F-001(b)(ii)).

<u>Project Change 2</u>: If an undergrounding project changed so significantly that the recorded costs and CBR no longer met the CPUC Guidelines Phase 2 conditions, the utility would record the costs for that project in the Memorandum Account that is subject to reasonableness review.

<u>Project Change 3</u>: In the unlikely case that a project changed from undergrounding to overhead hardening after passing through EUP Guidelines Screen 3, that overhead hardening project would be removed from the EUP, and costs would be recovered in another proceeding, such as the General Rate Case (GRC).

It is possible that Commission Staff may identify items that should be changed in the CPUC Guidelines themselves over the course of 10 years. These types of ministerial changes might include adding data fields to the Appendix 1 project data list or changing the information provided in the 6-month progress reports. On the other hand, issues could arise during the 10-year undergrounding program that would require changes to the

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can be carried out by Industry Divisions, such as Safety Policy Division and Energy Division. Agencies cannot delegate discretionary action without statutory authority.

[43] PFMs asks the Commission to make changes to an issued decision. See CPUC Rules of Practice and Procedure Rule 16.4.

CPUC Guidelines that would be more than ministerial changes. If that were to occur, then a petition for modification could potentially be required.

b. No, a petition for modification would not be required for changes to an undergrounding project. For the reasons described in response to Question F-003(a), the types of project changes we envision would either be addressed by procedures already incorporated in the CPUC Guidelines or cost recovery for the project would be moved to another proceeding. Because Energy Safety will be approving a Project Acceptance Framework, and not individual projects, there is no reason to submit a petition for modification each time there are changes to an undergrounding project.

**Question No. F-004:**

The current OEIS guidelines allows for a Confirmed Project to change within the 10-year period of the EUP.[44] How should the Commission address an undergrounding project where the trench length exceeds the forecasted estimate submitted to the Commission in an SB-884 Application?

a. Should there be a trench length exceedance threshold that:

    i. requires the project to be audited? Explain your answer.

    ii. triggers a PFM requirement? Explain your answer.

b. What data could be used to determine whether or not the exceedance threshold has been surpassed?

    i. Would the data collected through the OEIS Guidelines be sufficient? Why or why not?

**Response to Question No. F-004:**

As discussed in response in Question No. F-001, the EUP Guidelines and CPUC Guidelines outline requirements for reporting projects through the project lifecycle and the 10-year EUP plan. The EUP Guidelines require six-month progress reports that document any changes to the confirmed Undergrounding project. Changes to the scope of a project after the Cost-Benefit Ratio is calculated in Screen 2 of the Project Acceptance Framework, are expected as a project progresses through Screen 3.

a. No, any changes to the trench length determined through construction would be required for execution. The actual project details and costs would be incorporated into the CBR reported in the six-month progress reports; for example, in the Subproject Table that

[44] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

requires the pre and post mitigation length in miles.[45] These six-month reporting requirements mitigate the need for an audit or petition for modification.

b. Any scope changes will be analyzed against the EUP requirements including , project-level standards and key decision-making metrics (KDMMs). The six-month progress reports will document project progress and changes to the CBR or risk values as projects move through the Project Assessment Framework screens.

    i. The data collected and reported in the Progress Reports includes data points such as project risk reduction, unit cost, total cost, and cost benefit ratio[46] and pre and post mitigation lengths in miles.[47]

**<u>Question No. F-005:</u>**

Are the model version changes and calibration changes described in OEIS Guidelines 2.7.5.2 relevant to how the CPUC should handle undergrounding plan changes? Explain your position.

a. How, if at all, should an IOU report to the CPUC and stakeholders on updates to a model, including the Outage Program Risk model described in Section 2.7 of the OEIS SB-884 Guidelines,[48] which are still in development and not submitted or approved as part of an IOU's Wildfire Mitigation Plan (WMP)?

**<u>Response to Question No. F-005:</u>**

If a project has passed Screen 3 of the EUP Project Acceptance Framework, then the project will continue through execution based on the requirements outlined in the EUP Guidelines. Updates to risk models will not impact these projects, and these projects should continue to be evaluated using the risk model vintages used to confirm them.

If there is a model version change, PG&E will reanalyze projects that have not yet been confirmed through Screen 3 of the EUP Project Acceptance Framework, using the latest risk model version. The updated risk values would be reflected in the cost benefit ratios calculated for these projects and used for the purpose of cost recovery.

Risk model calibration changes are not relevant to how the CPUC should handle undergrounding plan changes. Calibration changes are understood to be minor updates to risk modeling as described in section 2.7.5.2 and are not anticipated to have meaningful changes to risk scores or CBRs for projects.

a. Any updates to the models will be reported in the EUP according to the requirements outlined in Section 2.5.7.2 of the EUP Guidelines. These requirements include

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45 EUP Guidelines, Section C.1.13.
46 EUP Guidelines, Section C.1.14.
47 EUP Guidelines, Section C.1.13.
48 EUP Guidelines, Section 2.7 at 24-41.

developing a model report for every new version of the risk model that outlines the methodology, calculations and a technical workbook. The model requirements for the Outage Program Model in the EUP are different from those in the Wildfire Mitigation Plan (WMP). PG&E will seek approval for the initial Outage Reliability Model that it will rely on for EUP decision-making in the EUP, and subsequent version changes will follow the aforementioned model report process.

**Question No. F-006:**

TURN stated in its May 29, 2024 comments on the OEIS Draft Guidelines that changes of at least 20% of circuits included in the EUP should trigger a new comment period of 10-15 days.[49] Cal Advocates similarly stated in its August 9, 2024 comments on PG&E's topics for Discussion of Revised Draft Guidelines that at each semiannual progress report new thresholds and risk models be used to re-evaluate the cost-effectiveness of projects in the current EUP work plan, to ensure that the thresholds are meaningful and the project prioritization evolves to reflect current information.[50]

a. State your position on these comments.

**Response to Question No. F-006:**

a. PG&E does not support a new comment period if there are changes of at least 20 percent of the circuits in the EUP. As described in response to Question F-001(a), a utility will submit an initial list of at least 25 undergrounding projects when it submits its EUP and then update the list of projects with each 6-month progress report. Because Energy Safety will be approving a Project Acceptance Framework, and not individual projects, there is no reason for stakeholders to submit comments each time the list of projects change as each one will have passed through the approved Project Acceptance Framework before it can be added to the project list.

   PG&E does not support Cal Advocates' recommendation that at each six-month progress report use new thresholds and risk models to re-evaluate the cost-effectiveness of projects in the current EUP work plan. We do, however, support allowing a utility to update its thresholds during a 10-year undergrounding plan.

   Regarding Cal Advocates' recommendation to re-evaluate projects based on new risk thresholds and new risk models, it is unrealistic to assume that a utility could update its risk models and risk thresholds every six months. PG&E anticipates updating its risk models approximately every 3-4 years, likely in rough alignment with the three-year WMP cycle. The EUP Guidelines require significant reporting and analysis associated with new risk models at least six months prior to integration new risk models versions

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49 See TURN Opening Comments on Draft 10-Year Electrical Undergrounding Plans Guidelines, May 29 2024 at 3 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56734&shareable=true

50 See Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines, August 9 2024 at 2 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57175&shareable=true

into an EUP,[51] making it impractical to update a risk model and risk thresholds with every semiannual progress report.

Wildfire risk is a dynamic, climate driven risk. As such, PG&E has chosen to model and quantify wildfire risk for the purposes of directing investments to the most effective locations, with a statistical, machine learning algorithm. While such an approach provides the best opportunity to predict a dynamic, climate driven risk, such as wildfire, the refresh of such a model with new manifestations of the risk is also dynamic. As such, measuring year over year risk reduction will also be subject to the same dynamic results commensurate with a dynamic risk. If short term risk reduction measures are required, a different approach should be used. It is suggested that accounting for risk reduction via established mitigation effectiveness factors would provide a more stable result that reflects the progress of mitigation work on the grid. Regarding updates to thresholds, PG&E explained in our October 3, 2024 Opening Comments on the EUP Revised Guidelines that we intend to use the outputs from our risk models to establish the various thresholds required in the EUP Guidelines and we expect that these outputs will change over time as risk models are updated. Therefore, PG&E does not support fixing the EUP thresholds for the duration of the EUP, as currently required. PG&E recommends that the EUP Guidelines allow a utility to change its thresholds when risk modeling versioning occurs. The utility would explain the changes in its Model Report[52] and would submit a request to change thresholds through a change order process.

## G. <u>How to Address Circuit Segments and Project Polygons</u>

**<u>Background:</u>**

Section 2.8.1 of the OEIS Guidelines requires IOUs to furnish updated tabular data with each Progress Report. Section 2.8.3 of the OEIS Guidelines requires IOUs to furnish updated information reported in geodatabase submissions in each Progress Report including the latest version of their projects in polygon form. Section 2.7.6 of the OEIS Guidelines require the IOUs to retain models and calibrations data for the lifetime of the program, but the OEIS Guidelines do not have an explicit retention policy regarding tabular data and geodatabase submission updates.

**<u>Question No. G-001:</u>**

Should the CPUC Guidelines include an explicit retention policy that requires the utilities to retain updates to the tabular data and geodatabase with each Progress Report for the lifetime of the program?

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[51] EUP Guidelines, Sections 2.7.2; 2.7.5.2; 2.7.6; and 2.7.7.

[52] EUP Guidelines Section 2.7.2.

**Response to Question No. G-001:**

PG&E is supportive of the CPUC issuing a retention policy requiring utilities to retain copies of the reported data submitted over the lifetime of the 10-year EUP.

**Question No. G-002:**

Should the polygons be updated after the Commission adopts a Decision on the utility's application? Why or why not?

**Response to Question No. G-002:**

PG&E interprets polygons in this question as "Confirmed Project Polygons" as defined in Section C.4.2 of the EUP Guidelines. These polygons do not need to be updated after the Commission issues an SB-884 Application decision because project information (including polygons) will be provided with the EUP submission and every six months after.

Further, EUP Guidelines Section C.4.2.d states, "[t]he Confirmed Project Polygon does not need to be redrawn due to changes in Circuit Segment topology…" and EUP Guidelines Section C.4.2.f states, "Confirmed Project Polygons are not to be edited in subsequent submissions." Therefore, updating the polygons after a CPUC decision will not yield new information that is not in the six-month progress reports.

## H. Number of Alternatives

**Background:**

Undergrounding refers to the practice of placing utility infrastructure, such as power lines, underground instead of using overhead poles and wires. Covered conductor refers to overhead lines encased with material thick enough to reduce the likelihood of sparks or faults, which in turn reduces the likelihood of causing fires or outages. Protection devices are switches, reclosers or sectionalizers installed on overhead power lines to isolate faults or shut off power, minimizing the scope and impact of outages or incidents. Other mitigations include, but are not limited to, practices such as vegetation management, which involves trimming or removing vegetation near power lines, and pole enhancements such as stronger, more fire-resistant materials (e.g., steel poles instead of wooden poles).

The OEIS guidelines require an IOU to compare two alternative mitigations.[53] An alternative to this approach is the idea of requiring utilities to present an "exhaustive list" of all possible mitigations, which could offer more comprehensive risk analysis but may be resource intensive.

**Question No. H-001:**

Should the CPUC limit alternatives to those required by OEIS, or should it require additional mitigation alternatives to be presented? Explain your answer.

**Response to Question No. H-001:**

The CPUC should support the existing EUP Guidelines and limit the alternatives to those required by Energy Safety. The CPUC should not require additional mitigation alternatives. The EUP Guidelines already require a Large Electrical Corporation to analyze several alternatives: (1) 100 percent undergrounded; (2) project as scoped (a hybrid project consisting of both undergrounding and overhead hardening on a single circuit segment); (3) undergrounding only portions of a hybrid project; (4) covered conductor with protective equipment and device settings, referred to as alternative Mitigation 1; and (5) mitigation or combinations of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1.[54] The number and type of EUP Guidelines-required alternatives are sufficient to demonstrate that the mitigation chosen by the Large Electrical Corporation for a project or subproject is appropriate.

If a Large Electrical Corporation is required to model and report on additional alternative mitigations it is likely that those mitigations alternatives would not be part of its suite of mitigation options, are operationally infeasible, or are cost prohibitive. Requiring these additional comparisons is unnecessary and would create additional work for alternatives we would not pursue. [55] and would no longer align to the EUP requirements for alternatives analysis.

**Question No. H-002:**

Should the CPUC allow utilities to tailor the number of alternatives analyzed based on specific circumstances, such as regional risks, or should a standard approach for all projects be required? Explain your answer.

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53 Alternative Mitigation 1 must include covered conductor in combination with some type of PEDS. Alternative Mitigation 2 must include one other mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1, including but not limited to remote fault detection technologies and high impedance fault detection. For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.10 at 41.

54 EUP Guidelines Section 2.7.10.

55 Please note PG&E raised this same concern with Energy Safety in our August 8, 2024, Comments on Issues Raised by PG&E and other Topics Discussed at the Workshop Held July 25, 2024, by Energy Safety on the Draft Electrical Underground Plan Guidelines, p. 6.

**Response to Question No. H-002:**

The CPUC approach should align with the alternative mitigation requirements in the EUP Guidelines. The EUP Guidelines list the alternatives that are required for every project (see response to Question H-001) and allow a Large Electrical Corporation to add additional alternative mitigations that it wishes to analyze and report.[56]

**Question No. H-003:**

How can the CPUC ensure that the analysis of alternative mitigations clearly, comprehensively and accurately compares costs and benefits of undergrounding, covered conductor, protection devices, and other mitigations?

**Response to Question No. H-003:**

The CPUC will have access to the information a utility uses to compare the costs and benefits of alternative mitigations and will be able to review and evaluate this information. The CPUC Guidelines allow for discovery and auditing of costs recorded to the balancing account,[57] providing avenues for the CPUC to gain comfort that the analysis of alternative mitigations clearly, comprehensively and accurately compares costs and benefits.

**Question No. H-004:**

Are there standards or regulations the CPUC should consider requiring for IOU projects and alternative mitigations, similar to Australia's Electricity Safety Bushfire Mitigation Regulations 2017[58]?

**Response to Question No. H-004:**

No, the CPUC should not consider requiring regulations similar to Australia's Electricity Safety Bushfire Mitigation Regulations 2017 (Australia Regulations). As noted in footnote 60, the Australia Regulations set guidelines and standards for protective devices' performance (*e.g.*, how fast switches should close and reduce voltage on a faulted line) and for other mitigation measures and outline additional requirements.

It would be unreasonable to establish guidelines or standards for protective devices' performance and for other mitigation measures because of the unique circumstances each utility is addressing

[56] EUP Guidelines, Section 2.7.10.

[57] CPUC Guidelines pp. 4-5.

[58] Electricity Safety (Bushfire Mitigation Duties) Regulations 2017 (legislation.vic.gov.au). These Regulations set guidelines and standards for protective devices' performance (e.g., how fast switches should close and reduce voltage on a faulted line) and for other mitigation measures.

through wildfire mitigation measures, most notably differences in risk tolerance and environmental factors.

The Commission opened a rulemaking proceeding to consider changes to existing policies, procedures, and rules for the safety, reliability and resiliency of electrical distribution systems (Rulemaking 24-05-023, p. 1). One of the issues raised in that rulemaking concerns establishing a common set of rules, standards or procedures for how a utility should configure its protective equipment to balance safety and reliability. Southern California Edison echoed the concerns we raise herein related to establishing common standards for protective device performance stating that it was not reasonable to set common rules across the utilities because, "[r]equiring all parties to apply the same standards or procedures is likely to negatively impact reliability or wildfire mitigation because many factors are unique to each IOU (*e.g*., circuit configuration and loading, service territory terrain and topology, population density of the Wildland-Urban Interface, etc.)."[59]

## I. Compliance with the Application

**Question No. I-001:**

If a project does not adhere to the timeline for completion included in its Application to the Commission, how should the Commission address this delay, and should delay affect cost recovery for that project?

**Response to Question No. I-001:**

Currently, the CPUC Guidelines do not include any requirements related to the timeline for completion for each undergrounding project. Moreover, whether an undergrounding project adheres to an estimated timeline for completion should not impact cost recovery and does not require action by the CPUC.

Due to the complex nature of undergrounding construction projects, certain projects may deviate from estimated timelines that, in many cases, have been established months or years before construction begins. Changes to undergrounding project timelines occur regularly. The CPUC Guidelines recognize that this occurs, noting, for example, "[e]xecuting the undergrounding takes place in two phases: (1) civil construction and (2) electric construction. Project schedules may be significantly impacted during civil construction."[60] Furthermore, to give visibility to how the project is progressing, the utility will provide updates on the status of the projects in each six-month progress report, as required by CPUC Guidelines Appendix 1: SB 884 Project List Data Requirements.

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[59] *See* Southern California Edison Company's Opening Comments to Order Instituting Rulemaking to Update Rules for the Safety, Reliability, and Resiliency of Electric Distribution Systems, Rulemaking 24-05-023, July 8, 2024, p. 11.

[60] CPUC Guidelines at 16, Appendix 1.

Cost recovery is predicated on a project being complete, used, and useful. Because a utility will submit projects for cost recovery only when the project is complete, it is irrelevant if a project adheres to the estimated timeline for completion. Over the life of the 10-year undergrounding program, certain projects will finish before the estimated completion date and some will finish after. Each year a utility will submit for cost recovery the batch of projects that were completed that year and recovery will be based on meeting the conditions for approval of plan costs.[61] Given that the Commission recognizes that there will be delays to project schedules, project status will be reported and that cost recovery will not be impacted if a project does not adhere to its estimated completion timeline, there is no need for the CPUC to address project delays.

## J. <u>How to Address Costs if an Application or Projects are Rejected or Abandoned</u>

**<u>Question No. J-001:</u>**

Undergrounding preparation costs could include permitting, site or right of way acquisition, labor/hiring, planning, environmental review and other operational costs incurred in planning an undergrounding project. What is your view on how the Commission should treat undergrounding preparation costs if the undergrounding project is not carried out and/or completed?

**<u>Response to Question No. J-001:</u>**

The treatment of undergrounding preparation costs depends on why the project is not carried out and/or completed. See response to Question J-002.

**<u>Question No. J-002:</u>**

Does your answer to Question J.1 depend on why the project was not carried out and/or completed? For instance:

a. Project denied by OEIS;

b. Project funding disapproved by CPUC;

c. Project abandoned by IOU; or

d. New legislation prevents the project from being carried out.

**<u>Response to Question No. J-002:</u>**

a. PG&E assumes that Energy Safety will not deny an undergrounding project that passes Screen 2.[62] However, if PG&E begins work post-Screen 2 activities and Energy Safety denies a post-Screen 2 project, PG&E would record the incurred costs in the

61 CPUC Guidelines at 10-11.
62 EUP Guidelines, Section 2.4.4.

Undergrounding Memorandum Account and seek recovery through reasonableness review.

b. Project costs recorded to the Undergrounding Balancing Account that are not approved by the CPUC would be moved to the Undergrounding Memorandum Account for reasonableness review.

c. If a utility abandons a project for reasons that could not have been foreseen or addressed by the utility (*e.g.* failure to secure necessary easements or permits) or for constructability reasons, a utility could record the incurred costs in the Memorandum Account and seek recovery through reasonableness review.

   If a utility simply chooses to abandon a project, it should not recover costs for that project.

d. If new legislation were enacted that prevented a utility from carrying out a project, the utility would record the incurred costs in the Undergrounding Memorandum Account and seek recovery through reasonableness review.

**Question No. J-003:**

Generally, costs incurred prior to plant being placed in service and deemed used and useful are recorded as Allowance for Funds Used During Construction (AFUDC) costs. AFUDC is typically used for projects that are expected to be constructed and be placed into rate base so they can earn a rate of return.

a. Should SB 884 undergrounding costs be treated as AFUDC if a project is rejected by OEIS or cost recovery for the project is denied by the CPUC?

b. Should AFUDC costs related to a project that is rejected, denied or abandoned be recovered in an IOU's General Rate Case or should the CPUC solely determine cost recovery for costs of projects that are not yet completed in SB 884 project applications?

c. How should IOUs record costs related to projects that are in progress but not yet completed to avoid retroactive ratemaking?[63] IOUs responding shall specify in which account they plan to record pre-Application costs and how they propose to seek cost recovery for those costs if a project is rejected, denied or abandoned.

**Response to Question No. J-003:**

a. If cost recovery for the project is denied by the CPUC, PG&E would cancel the project and reverse all accrued AFUDC.

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[63] Rates are set on the cost of doing business which the utility files in a rate case. The resulting Decision of the rate case is applied going forward and is never retroactive.

b. See response to part (a). If a project is rejected or denied, then the AFUDC would be reversed and the project cancelled. For abandoned plant costs, this issue is addressed above in response to Question J-002. The only exception would be if the Commission determined that costs included in the SB-884 Application are reasonable but not incremental to adopted amounts in PG&E's GRC. In that case, recovery should continue in the GRC with no change.

c. Costs for projects in progress but not yet completed are recorded to Account 107 - Construction Work In Progress. See parts (a) and (b) above.

**Question No. J-004:**

Should the CPUC impose a requirement that if an SB-884 project reaches a certain stage it needs to be completed? Explain your answer.

**Response to Question No. J-004:**

No, the CPUC should not impose a requirement that if an SB-884 project reaches a certain stage it needs to be completed. Decisions regarding whether to complete a project should be left to construction experts based on specific issues related to a project.

**Question No. J-005:**

Should the Commission develop guidelines pertinent to abandoned projects (i.e., projects the IOU opts not to complete or use)? If so, what positions should the guidelines take?

a. Should any relate to cost recovery; and if so what positions should they take?

b. Should any relate to removal of facilities; and if so what positions should they take?

c. What other guidelines should there be?

**Response to Question No. J-005:**

~~a.~~ As discussed in response to Question J-002, the utilities should be allowed to record the incurred costs in the Memorandum Account and seek recovery through reasonableness review for projects that are abandoned for reasons that could not have been foreseen or addressed by an IOU (e.g. inability to secure necessary easements or permits)-

b. If a utility abandoned an undergrounding project that was partially constructed and if, in that case, the removal of facilities was required, the utility should remove them.

c. No guidelines are necessary related to abandoned projects.

**Question No. J-006:**

Should the CPUC impose a requirement that a project that has remained at a particular stage for more than a certain period should be reported as abandoned?

a. If so, what should the CPUC require regarding cost recovery and other activity on that project?

b. If so, at what stage(s) of the project should it be reported as abandoned? How much time should elapse within that stage for the CPUC to require the utility to report the project as abandoned?

c. If not, why not?

**Response to Question No. J-006:**

No, the CPUC should not impose a requirement that a project that has remained at a particular stage for more than a certain period should be reported as abandoned.

a. N/A

b. N/A

c. It is unreasonable to assign a time requirement for projects moving from one project lifecycle stage to the next. All undergrounding projects are unique and some will move quickly through the project lifecycle while others will not based on may factors including, but not limited to: permitting, land rights, and weather. Arbitrarily assigning time limits on the project lifecycle stages could inadvertently require a utility to abandon a valuable undergrounding project for no meaningful reason.

**Question No. J-007:**

New Jersey has a rule that relates to cost recovery for abandoned projects that were part of an accelerated level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing, critical water distribution components that enhance safety, reliability, water quality, system flows and pressure, and/or conservation.

The rule states:

If within three years after the effective date of a Foundational Filing, a water utility has not filed a petition in accordance with the Board's rules for the setting of its base rates, all interim charges collected under the DSIC rate shall be deemed an over-recovery, and shall be credited to customers in accordance with this subchapter. A water utility may seek recovery of such projects in the ordinary course through its next base rate case. Notwithstanding the above, a water utility may continue to collect a DSIC charge during a pending rate case filed in accordance with this section.[64]

a. Should the CPUC develop a similar requirement for SB 884 undergrounding projects? Explain your answer.

**Response to Question No. J-007:**

a. No, the CPUC should not develop a similar requirement for SB884 undergrounding projects. In the unlikely event that a utility abandons an undergrounding project, the utility should be allowed to recover costs as described in response to Question J-002.

   Through six-month reporting to both Energy Safety and the CPUC, stakeholders will be able to track the status of each undergrounding project and will be able to see if certain projects are not moving through the project lifecycle.[65] If regulators are concerned about the status of an individual project, a utility can provide information about that project through discovery or in response to requested additional reporting.

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64 New Jersey Administrative Code 14:9-10.4 (e) - DSIC Foundational Filing https://casetext.com/regulation/new-jersey-administrative-code/title-14-public-utilities/chapter-9-water-and-wastewater/subchapter-10-distribution-system-improvement-charge/section-149-104-dsic-foundational-filing

65 CPUC Guidelines, Appendix 1 and EUP Guidelines, Table C.13.

November 12, 2024

**Via Electronic Filing**

Danjel Bout, Director
Safety Policy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
SB884@cpuc.ca.gov

**Subject: Public Advocates Office's Informal Comments on Questions for Stakeholders Regarding the CPUC SB-884 Guidelines**

Dear Director Bout,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits informal comments on the Questions for Stakeholders Regarding the CPUC SB-884 Guidelines.

Please contact Nat Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these informal comments.

We respectfully urge the Commission to adopt the recommendations discussed herein.

Sincerely,

/s/ ***Angela Wuerth***
Angela Wuerth
Attorney

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cc: SB-884 Notification List
Service List A.24-05-008

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# I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these informal comments in response to Safety Policy Division's (SPD) Staff questions for Senate Bill (SB) 884 Guidelines issued October 14, 2024 (Staff Questions). Each utility that submits an undergrounding plan under SB 884 should be held accountable for executing its plan in a timely and cost-effective manner. If a utility fails to do so, it risks not meeting the California Public Utilities Commission's (Commission) affordability principle, wasting ratepayer resources, and failing to meet the utility's wildfire risk reduction targets.

The Staff Questions lend appropriate weight to these matters and inquiries about several reasonable requirements that utilities must meet in SB 884 applications at the Commission. Cal Advocates appreciates SPD's efforts to ensure that large-scale utility undergrounding programs developed under SB 884 will substantially improve the safety and reliability of electric distribution systems while minimizing detrimental impacts to ratepayers. In these informal comments, we propose refinements to the current Resolution SPD-15 to maximize the public benefit of these plans, tighten accountability measures, and ensure all undergrounding expenditures are just and reasonable.

# II. ISSUES

## A. The Commission should host another workshop on the results of operation models (RO models).

The Staff Questions on RO models are complex and should be explored in workshops.[1] In the past, Energy Division hosted a workshop on the uniformity of RO models, which explored standardization for the General Rate Case (GRC).[2] That SPD should collaborate with Energy Division to host a workshop on RO models uniformity in the SB 884 application, is confirmed by the fact that SPD is asking questions that have

[1] SPD, Questions for Stakeholders Regarding the CPUC SB-884 Guidelines (Staff Questions), October 14, 2024 at Questions A.1-8.

[2] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3, November 19, 2020.

been partially explored by Energy Division.[3] A joint workshop would also benefit both the Energy Division and SPD, because it will provide insight into how Pacific Gas and Electric Company's (PG&E), or possibly any other utility's, mini-RO models in their SB 884 plans might affect cost recovery in the GRC. This approach is consistent with past practice where SPD and Energy Division partnered together.[4] A joint workshop on uniformity of RO models would be a good opportunity for further collaboration.

The joint workshop should explore SPD's questions about PG&E's usage of a separate and different standalone mini-RO model in their SB884 plans when compared to the RO model used in the GRC.[5] If cost recovery applications in different proceedings use different RO models, it may be difficult to determine whether overhead lines that have been undergrounded as part of an SB 884 plan have been removed from the rate base in future GRCs. In addition, the workshop can explore PG&E's mini-RO model and the lack of depreciation studies,[6] because the basic calculus of the RO model includes depreciation expense.[7]

### B. The Commission should establish a per-project minimum cost-benefit ratio (CBR) threshold and ensure utilities follow CBR thresholds.

CBR minimums protect ratepayers from unreasonable rate increases that could result from inefficient undergrounding, where cheaper alternatives such as covered conductor are more efficient. The Commission currently has an average CBR threshold for all projects completed in any given two-year period (the current and the prior year) which must equal or exceed the approved threshold CBR for that current year.[8] In

[3] Energy Division, Uniformity in Results of Operations (RO) Model Workshop #3 Report at 2-3.

[4] Energy Division and SPD, R.20-07-013 and R.18-04-019 Joint Workshop, September 13, 2023.

[5] Staff Questions at Questions A.5.

[6] PG&E should explain the validity of depreciation expense calculations without depreciation studies (Staff Questions at Questions A.6) in the workshop.

[7] D.23-11-069 in A.21-06-021, *Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company*, November 16, 2023, at 652-653.

[8] SPD, Resolution SPD-15, March 7, 2024 at 11.

addition, Cal Advocates has advocated for CBR thresholds for both the SB 884 undergrounding plan as whole and on per project basis.[9] Cal Advocates is concerned that utilities could select costly projects over alternatives with a higher benefit to cost ratio. These concerns are based on PG&E's recent issues in the 2024 Risk Assessment Mitigation Phase (RAMP).

Specifically, in discovery, Cal Advocates learned that PG&E's cost-benefits analysis overwhelmingly favored covered conductor as a wildfire mitigation over costly and slow undergrounding.[10] PG&E described its reasoning for selecting undergrounding over covered conductor in a brief, unsupported narrative response, even though its own cost-benefits analysis showed that covered conductor had a higher CBR.[11]

In addition, Cal Advocates is concerned that utilities could manipulate mitigation analyses to favor undergrounding over less costly alternatives. Cal Advocates commented on these issues in PG&E's 2023-2025 WMP. Among other things, Cal Advocates notes that:[12]

- PG&E does not always follow the CBR methodology adopted in R.20-07-013. Instead, PG&E sometimes uses a Wildfire Benefit Cost Analysis (WBCA), which is a "net benefit" of a mitigation analysis.[13]
- PG&E uses a WBCA analysis to claim undergrounding generates a higher estimated lifetime benefit compared to covered conductor. However, CBR calculations would show that for the same circuit segment, overhead hardening would have been more cost efficient.[14]

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[9] *Public Advocates Office's Reply Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program*, January 11, 2024 at 2-3.

[10] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[11] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 1, October 2, 2024.*

[12] *Public Advocates Office's Reply Comments on the Draft Decision Approving Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, December 14, 2023 at 4-6.

[13] Net benefit definition: Mitigation is calculated by subtracting the capital and operating expenditures associated with a mitigation from the estimated benefits delivered by that mitigation.

[14] Level 4 Ventures, *Comparing the MAVF and RSE with the proposed Cost-benefit framework*, August 2022. Cost efficient definition: If the CBR is greater than one for a mitigation, it means that the dollar benefit is greater than its dollar cost.

Based on PG&E's recent issues, which show the need to prevent utilities from manipulating the mitigation analysis to favor undergrounding, the Commission should make CBR requirements more stringent.

### C. The Commission should require timely audits that include a reexamination of the utility's alternative mitigation and CBR analyses and verification that the projects are complete.

The Commission's SB 884 Guidelines require that costs submitted in an SB 884 Application meet certain conditions (Phase 2 Conditions) for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit.[16] The statute requires an up-front determination, before cost recovery is authorized, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[17]

This audit should at a minimum include reexamination of the utility's alternative mitigation comparison and CBR analysis for each project. A reexamination of the utility's CBR analysis, with updates based on recorded costs rather than projected costs, would enable the Commission to more accurately compare alternatives.[18]

In addition, the Commission should verify that undergrounding projects are completed, risks are reduced, and undergrounding projects are operational before authorizing cost recovery for such projects. Energy Safety auditors on an annual basis issue a Notice of Violation (NOV) on Wildfire Mitigation Plan (WMP) projects that are identified as completed but were not actually done.[19] To prevent this issue from happening in SB 884, the Commission should require utilities to verify that projects are completed. For example, project verification could include a mix of mapped location

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[15] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[16] SPD, SB 884 Program: CPUC Guidelines, March 2024, at 4.

[17] Public Utilities Code section 8388.5(e)(6).

[18] Alternatives to undergrounding include covered conductor with enhanced powerline safety settings (EPSS). PG&E uses the term EPSS. Other utilities use terms such as Fast Curve Settings, Sensitive Relay Profile, and etc.

[19] Energy Safety, *2023 COMPLIANCE PROCESS,* July 2023 at 8-9.

data, photographic evidence, and satellite imagery. Utility companies already provide photographs for grid hardening and other initiatives, along with spatial data in their WMP Geographic Information System (GIS) Quarterly Data Reports (QDR).[20] Therefore, utilities should be able to provide verification that projects are complete in the context of SB 884.

### D. The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

Decision 24-05-064 requires utilities to present the results of three discount rate scenarios for their Risk-based Decision-making Framework (RDF) CBR calculations.[21] The Commission should require utilities to present NPV Benefits, NPV Costs, and CBR using each of these three discount rates in their SB-884 Applications.

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[20] Energy Safety, Data Guidelines v3.2, January 30, 2024 at 6.

[21] D.24-05-064 in R.20-07-013, *Phase 3*, July 6, 2024, at 102-05. The required three discounted rates scenario are listed below:

> Societal Discount Rate Scenario: apply the latest available near-term social rate of time preference (SRTP) provided by the U.S. Office of Management and Budget (OMB) in Circular A-4, as the discount rate to all components in both the numerator and denominator of the CBR. The latest available near-term SRTP is 2%,
>
> WACC Discount Rate Scenario: apply the IOU's most recent Weighted-Average Cost of Capital as the discount rate for all components in both the numerator and denominator of the CBR, and
>
> Hybrid Discount Rate Scenario: apply the discount rate derived from the effective compounded rate of the 10-year effective average inflation rate as measured by the California statewide consumer price index, the 10-year effective average per-capita real growth rate of wages as measured by California statewide mean hourly and total wages for all occupations, and the most recent near-term SRTP used in the Societal Discount Rate Scenario, to the safety and reliability components of the numerator and apply the IOU's most recent WACC as the discount rate for the financial components of the numerator and denominator of the CBR.

### E. The Commission must not allow utilities to add miles of undergrounding to projects because it violates statutory requirements.

Public Utilities Code section 8388.5(c) requires each plan submitted to Energy Safety to include all projects that will be constructed.[22] Cal Advocates has submitted multiple comments on this statutory requirement to Energy Safety.[23, 24] Any project not included as part of a utility's initial SB 884 plan submission cannot be constructed as part

---

[22] Public Utilities Code section 8388.5(c):

> In order to participate in the program, a large electrical corporation shall submit to the office a distribution infrastructure undergrounding plan that shall address or include, at minimum, all of the following components:
>
> (1) A 10-year plan for undergrounding distribution infrastructure.

(2) Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in tier 2 or 3 high fire-threat districts or rebuild areas may be considered and constructed as part of the program.

[23] See discussions in:

Cal Advocates, TURN, and MGRA, Joint Letter: "Implementation of Senate Bill 884 – Ten-Year Undergrounding Plans," April 26, 2023 (filed in docket 2023-UPs on December 13, 2023) at 2 and Appendix A: "SB 884 requires the undergrounding plans to include detailed project-specific information demonstrating that undergrounding is the superior alternative when these factors are considered. … The SB 884 process should require utilities to make this showing for each project before rate recovery for undergrounding is allowed."

*Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023 at 10 (filed as Appendix A of *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, November 2, 2023 in docket 2023-UPs).

Discussion in Public Workshop on Draft Electrical Undergrounding Plan Guidelines, May 15, 2024.

Discussion in Public Workshop on Revised Draft Electrical Undergrounding Plan Guidelines, July 25, 2024.

*Corrected Comments of the Public Advocates Office on Pacific Gas and Electric's Topics for Discussion on Revised Draft EUP Guidelines*, August 9, 2024 in docket 2023-UPs, at 5-6:

> Energy Safety has stated that its responsibility is to approve electrical undergrounding plans rather than projects. Energy Safety's draft proposal defines a "plan" as a decision-making process for developing, selecting, and prioritizing undergrounding projects; Energy Safety does not regard a plan as entailing specific projects or workplans. This view is inconsistent with the language of SB 884. Energy Safety's interpretation of SB 884 relies on Public Utilities Code section 8388.5(d) while overlooking section 8388.5(c).

*Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP)*, October 3, 2024 in docket 2023-UPs at 11-12.

[24] Staff Questions at Questions F.1-6.

of the plan, and the Commission cannot approve cost recovery for such a project.[25] Allowing utilities to add miles by changing the scope of projects compared to the initial submission is inconsistent with Public Utilities Code section 8388.5(c). Utilities could pursue funding in their GRCs for additional undergrounding miles that are not included in the initial project list submitted with the SB 884 plan, instead of violating Public Utilities Code section 8388.5(c).

### F. The Commission should require utilities to retain historical data and provide updated data quarterly.

Cal Advocates has submitted comments in the past to Energy Safety that are relevant to SPD's inquiries about tabular and GIS requirements.[26] GIS and tabular project data have been a standing requirement for the WMP QDRs since their inception.[27] Underground projects are already a subset of the data requested as part of the WMP QDRs. Because Energy Safety QDRs have been required for several years they form a *de facto* historic record of system updates and changes from which the impacts of wildfire mitigation can be synthesized. However, this record is imperfect and relies on substantial amounts of *post hoc* processing to make it useful. Cal Advocates recommends close coordination between SPD and Energy Safety to develop data requirements that ensure there are explicit spatial and tabular data retention policy requirements for projects in an SB 884 plan; this data should be part of the validation process discussed in Section C. The availability of historic spatial records for electrical systems is especially important for tracking the risk reduction accrued to SB 884 projects. Knowing exactly which assets have been removed from service is the only way to accurately estimate the risk reduction attributable to a specific project.

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[25] Public Utilities Code section 8388.5(c).

[26] *Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines*, August 9, 2024 at 3-4.

[27] Energy Safety, *GIS Data Reporting Standard v2.1*, September 22, 2021 at 114.

### G. The Commission should require utilities to analyze all reasonable mitigation alternatives and the impacts on customer rates.

Cal Advocates has concerns with the alternatives analysis that PG&E submitted as part of its RAMP ahead of its GRC filing in 2025.[28] Cal Advocates previously shared these concerns with Energy Safety and reiterates these concerns here in response to some of the Staff Questions.[29, 30] PG&E's "alternative" to undergrounding was simply to not underground secondary and service lines.[31] Other alternatives were Grid Monitoring, reconfiguration of conductor attachments, and wildfire resilience partnerships (fuels) treatment.[32] However, PG&E fails to consider covered conductor with Enhanced Powerline Safety Settings (EPSS or fast trip) as an alternative mitigation.[33]

In addition, by its own admission, PG&E:[34, 35, 36]

- Did not analyze covered conductor as an alternative to its undergrounding proposal in the RAMP application.
- Reported its proposed undergrounding program would cost $6.5 billion.
- Reported an overhead covered conductor program alternative would cost $1.7 billion.
- Did not quantify the impacts of alternative mitigation programs on customer rates when selecting between risk mitigation programs in its RAMP.

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[28] See A.24-05-008, *Application of PG&E to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, May 15, 2024 (PG&E's RAMP Report), at PG&E-4, 1-98 to 1-105.

[29] *Public Advocates Office's Reply Comments on the Updated Revised Draft Guidelines for the 10-Year Electrical Undergrounding Plan*, October 14, 2024 in docket 2023-UPs at 3-4.

[30] Staff Questions at Questions H.1-4.

[31] PG&E's RAMP Report at PG&E-4, 1-98 and 4-45.

[32] PG&E's RAMP Report at PG&E-4, 1-100, 1-102, 1-104, 4-48.

[33] PG&E's Ramp Report at PG&E-4 1-100 to 1-105.

[34] See generally PG&E's RAMP Report; *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02*, question 1, September 10, 2024.

[35] *PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN04, question 2, Attachment 1, October 4, 2024.*

[36] PG&E's response to data request CalAdvocates-PGE-2024-RAMP-AYN02, question 3, September 10, 2024.

Thus, as stated in previous comments, PG&E's comparisons of undergrounding with covered conductor are not reasonable.[37] PG&E consistently compares undergrounding to covered conductor as a standalone alternative, failing to combine covered conductor with EPSS.[38] PG&E's own estimates suggest that covered conductor with EPSS is approximately twelve percentage points more effective than covered conductor alone.[39] Further, in its reports to investors, PG&E estimates that PG&E's wildfire mitigation plans and the layers of protection provided by EPSS, Public Safety Power Shutoffs, enhanced situational awareness, and suppression resources reduce economic losses by 93 percent.[40]

The Commission should require utilities to analyze all reasonable mitigation alternatives in SB 884 to avoid the issues seen in the RAMP and WMP. In addition, the Commission should consider Executive Order N-5-24 and its possible impact on SB 884 alternative mitigations analysis requirements. Executive Order N-5-24 has language related to wildfire mitigation and managing costs.[41]

### H. The Commission must not allow cost recovery for abandoned projects because such costs are not just and reasonable.

Utilities' cost recovery for abandoned undergrounding projects does not comport with Public Utilities Code Section 8388.5(e)(6), which requires SB 884 project costs

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[37] *Public Advocates Office's Comments on the Updated Revised Draft Guidelines for the 10 Year Electrical Undergrounding Plan (EUP)*, October 3, 2024 in Docket 2023-UPs at 1-3.

[38] *Comments of the Public Advocates Office on PG&E's 2025 Wildfire Mitigation Plan Update*, May 7, 2024 in docket 2023-2025 WMPs at 38.

[39] See Table ACI-PG&E-23-05-3 in PG&E, 2025 Wildfire Mitigation Plan Update R1, July 5, 2024 at 56. This table lists the effectiveness of covered conductor as 66.4 percent, the effectiveness of covered conductor with EPSS as 78.2 percent, and the effectiveness of undergrounding primary lines as 97.7 percent.

[40] PG&E Corporation 2024 Second Quarter Earnings, Slides 5, 20, 22, 30. https://s1.q4cdn.com/880135780/files/doc_financials/2024/q2/Q224-Earnings-Presentation.pdf

[41] Executive Order N-5-24, October 30, 2024.

https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf

Language relating to wildfire mitigation and managing costs, "utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers."

authorized by the Commission to be just and reasonable.[42] Allowing recovery of costs for abandoned undergrounding projects is inconsistent with the "used and useful" principle, which provides that ratepayers should not pay for assets for which they are not receiving service.[43] Ratepayers have not and do not receive benefits from abandoned undergrounding projects.

Furthermore, allowing recovery of costs for abandoned undergrounding projects is inconsistent with the purpose of SB 884, which is to increase electrical reliability and reduce the risk of wildfires.[44] Abandoned undergrounding projects do not accomplish these goals. Therefore, the Commission cannot lawfully allow cost recovery for abandoned undergrounding projects.

## III. CONCLUSION

Cal Advocates respectfully requests that Safety Policy Division adopt the recommendations discussed herein.

Respectfully submitted,

/s/ *Angela Wuerth*
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[42] Public Utilities Code § 8388.5(e)(6); Public Utilities Code § 451.

[43] *See, e.g.,* D.18-12-021 at 154; D.84-09-055, 16 CPUC 2d 205, 228.

[44] See Public Utilities Code § 8388.5(d)(2) ("The office may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire."); Senate Bill 884 (2022), Bill Analysis, Assembly Committee on Utilities and Energy, June 22, 2022 Hearing, at 5 (Author's Statement).

# APPENDIX

| Page # | Description |
|---|---|
| A-1 | RAMP-2024_DR_CalAdvocates_002-Q001 |
| A-2 | RAMP-2024_DR_CalAdvocates_002-Q003 |
| A-3 | RAMP-2024_DR_CalAdvocates_004-Q001 |
| A-4 | RAMP-2024_DR_CalAdvocates_004-Q002Atch01 |

**PACIFIC GAS AND ELECTRIC COMPANY**
**RAMP 2024**
**Application 24-05-008**
**Data Response**

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | CalAdvocates_002-Q001 | | |
| PG&E File Name: | RAMP-2024_DR_CalAdvocates_002-Q001 | | |
| Request Date: | August 23, 2024 | Requester DR No.: | 002 |
| Date Sent: | September 10, 2024 | Requesting Party: | Public Advocates Office |
| PG&E Witness: | N/A | Requester: | Anna Yang |

**QUESTION 001**

Please provide PG&E[s analysis of replacing primary conductors with covered conductors as a wildfire mitigation alternative to undergrounding primary conductors.

**ANSWER 001**

Below is the CBR results of the two scenarios for overhead hardening the primary line miles included in the proposed undergrounding plan M022 and alternative undergrounding plan A001,.

- Scenario 1: overhead hardening for primary miles included in M022
- Scenario 2: overhead hardening for primary miles included in A001

| Scenario | Program 2027-2030 (NPV) | | | |
|---|---|---|---|---|
| | [A] Total Program Cost ($M) | [B] Foundational Activity Cost ($M) | [C] Risk Reduction | [C]/([A]+[B]) CBR |
| **Scenario 1** | $1,695 | 0.0 | 30,356 | 17.9 |
| **Scenario 2** | $2,286 | 0.0 | 40,138 | 17.6 |

Aggregated analysis is provided in the RAMP-2024_DR_CalAdvocates_002-Q001Atch07.xlsx, and individual analysis in the CBR Input Files can be found in the attachments referenced below.

Scenario 1:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch01_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch02_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch03_PCEEE.xlsx

Scenario 2:

- RAMP-2024_DR_CalAdvocates_002-Q001Atch04_WLDFR.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch05_DOVHD.xlsx
- RAMP-2024_DR_CalAdvocates_002-Q001Atch06_PCEEE.xlsx

**PACIFIC GAS AND ELECTRIC COMPANY**
**RAMP 2024**
**Application 24-05-008**
**Data Response**

| PG&E Data Request No.: | CalAdvocates_002-Q003 | | |
|---|---|---|---|
| PG&E File Name: | RAMP-2024_DR_CalAdvocates_002-Q003 | | |
| Request Date: | August 23, 2024 | Requester DR No.: | 002 |
| Date Sent: | September 9, 2024 | Requesting Party: | Public Advocates Office |
| PG&E Witness: | N/A | Requester: | Anna Yang |

**QUESTION 003**

Please provide PG&E's analysis for how it quantifies the impacts of costly investments on customer rates.

**ANSWER 003**

PG&E did not conduct an analysis of this issue in its RAMP Report. The RAMP is not a funding request and does not evaluate the impact of investments on customer rates.

**PACIFIC GAS AND ELECTRIC COMPANY**
**RAMP 2024**
**Application 24-05-008**
**Data Response**

| | |
|---|---|
| **PG&E Data Request No.:** | CalAdvocates_004-Q001 |
| **PG&E File Name:** | RAMP-2024_DR_CalAdvocates_004-Q001 |
| **Request Date:** | October 2, 2024 |
| **Requester DR No.:** | 004 |
| **Requesting Party:** | Public Advocates Office |
| **Requester:** | Anna Yang |
| **Date Sent:** | October 4, 2024 |
| **PG&E Witness(es):** | N/A |

### QUESTION 001

In PG&E's RAMP Application, PG&E included two undergrounding proposals: M022 and A001. Please provide a justification for why PG&E selected undergrounding for each of these two mitigation proposals instead of covered conductor. In the justification, please include an explanation of all factors that PG&E considered for each proposal and how PG&E used such factors to arrive at its decision to select undergrounding instead of covered conductor.

### ANSWER 001

PG&E chose undergrounding as our preferred mitigation because it provides the most wildfire risk reduction, significantly improves customer reliability, especially surrounding EPSS and PSPS outages, and provides an electric distribution system which is more resilient to the adverse impacts of climate change with deep uncertainty. Undergrounding also substantially addresses factors such as ingress/egress and tree fall-in risk, which are not mitigated by an overhead alternative. Additional considerations influencing the decision to pursue the most risk reducing mitigation include Risk Tolerance, modeling limitations, and other uncertainties affecting the analysis.

For more information on PG&E's undergrounding mitigation please see PG&E's 2023-2025 WMP: 2023-2025 Wildfire Mitigation Plan R6 (pge.com), sections 8.1.2.1 and 8.1.2.2.

# PACIFIC GAS AND ELECTRIC COMPANY
# RAMP 2024
# Application 24-05-008
# PG&E File Name: RAMP-2024_DR_CalAdvocates_004-Q002Atch01

| FA | Risk ID | Program Type | Program ID | MWC or MAT | Program 2027-2030 $M (NPV) | | | | Program-Risk 2027-2030 $M (NPV) | | | | Unit of Work | | | | Capital ($000) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | [A] Total Program Cost | [B] Foundational Activity Cost | [C] Risk Reduction | [C]/([A]+[B]) CBR | [A] Total Program Cost | [B] Foundational Activity Cost | [C] Risk Reduction | [C]/([A]+[B]) CBR | 2027 | 2028 | 2029 | 2030 | 2027 | 2028 | 2029 | 2030 |
| EO | WLDFR | Mitigation | WLDFR-M002 (M022 Alternative) | 08W | $ 1,695 | $ - | $ 30,356 | 17.9 | $1,695 | $0 | $29,570 | 17.4 | 263 | 316 | 368 | 421 | $ 327,702 | $ 405,197 | $ 486,912 | $ 573,165 |
| EO | DOVHD | Mitigation | DOVHD-M002 (M022 Alternative) | 08W | $ 1,695 | $ - | $ 30,356 | 17.9 | $1,695 | $0 | $786 | 0.5 | 263 | 316 | 368 | 421 | $ 327,702 | $ 405,197 | $ 486,912 | $ 573,165 |
| EO | PCEEE | Mitigation | PCEEE-M002 (M022 Alternative) | 08W | $ 1,695 | $ - | $ 30,356 | 17.9 | $1,695 | $0 | $0 | 0.0 | 263 | 316 | 368 | 421 | $ 327,702 | $ 405,197 | $ 486,912 | $ 573,165 |
| EO | WLDFR | Mitigation | WLDFR-M002 (A001 Alternative) | 08W | $ 2,286 | $ - | $ 40,138 | 17.6 | $2,286 | $0 | $39,185 | 17.1 | 400 | 440 | 480 | 520 | $ 497,684 | $ 564,574 | $ 634,376 | $ 707,858 |
| EO | DOVHD | Mitigation | DOVHD-M002 (A001 Alternative) | 08W | $ 2,286 | $ - | $ 40,138 | 17.6 | $2,286 | $0 | $953 | 0.4 | 400 | 440 | 480 | 520 | $ 497,684 | $ 564,574 | $ 634,376 | $ 707,858 |
| EO | PCEEE | Mitigation | PCEEE-M002 (A001 Alternative) | 08W | $ 2,286 | $ - | $ 40,138 | 17.6 | $2,286 | $0 | $0 | 0.0 | 400 | 440 | 480 | 520 | $ 497,684 | $ 564,574 | $ 634,376 | $ 707,858 |
| PG&E's Original Proposals in the RAMP Application Below | | | | | | | | | | | | | | | | | | | | |
| EO | WLDFR | Mitigation | WLDFR-M022 (M022) | 08W | $6,483 | $ - | $ 51,321 | 7.9 | $6,483 | $ - | $50,295 | 7.8 | 400 | 480 | 560 | 640 | $ 1,320,501 | $ 1,575,164 | $ 1,852,955 | $ 2,139,167 |
| EO | DOVHD | Mitigation | DOVHD-M022 (M022) | 08W | $6,483 | $ - | $ 51,321 | 7.9 | $6,483 | $ - | $1,020 | 0.2 | 263 | 316 | 368 | 421 | $ 1,320,501 | $ 1,575,164 | $ 1,852,955 | $ 2,139,167 |
| EO | PCEEE | Mitigation | PCEEE-M003 (M022) | 08W | $6,483 | $ - | $ 51,321 | 7.9 | $6,483 | $ - | $6 | 0.0 | 263 | 316 | 368 | 421 | $ 1,320,501 | $ 1,575,164 | $ 1,852,955 | $ 2,139,167 |
| EO | WLDFR | Mitigation | WLDFR-A001 (A001) | 08W | $6,261 | $ - | $ 60,724 | 9.7 | $6,261 | $ - | $59,476 | 9.5 | 400 | 440 | 480 | 520 | $ 1,459,940 | $ 1,571,705 | $ 1,714,569 | $ 1,861,676 |
| EO | DOVHD | Mitigation | DOVHD-A001 (A001) | 08W | $6,261 | $ - | $ 60,724 | 9.7 | $6,261 | $ - | $1,240 | 0.2 | 400 | 440 | 480 | 520 | $ 1,459,940 | $ 1,571,705 | $ 1,714,569 | $ 1,861,676 |
| EO | PCEEE | Mitigation | PCEEE-A003 (A001) | 08W | $6,261 | $ - | $ 60,724 | 9.7 | $6,261 | $ - | $8 | 0.0 | 400 | 440 | 480 | 520 | $ 1,459,940 | $ 1,571,705 | $ 1,714,569 | $ 1,861,676 |

# Questions for Stakeholders Regarding the CPUC SB-884 Guidelines

October 14 2024

## Instructions:

- If any question in this document calls for a "yes" or "no" answer, please explain your answer rather than simply giving a one-word answer.
- The reference to Office of Energy Infrastructure (OEIS) Guidelines in these questions is intended to refer to the Guidelines in place at the time these questions are asked. The Guidelines are available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57358&shareable=true. We acknowledge those Guidelines may change in the future.
- The Commission SB-884 Guidelines refers to Resolution SPD-15, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K984/526984185.pdf. The Commission may update the Guidelines in the future.
- Each "Background" section below represents only a partial summary of the relevant context. Please refer to other resources, inlcuding the OEIS Guidelines and the Commission's SB-884 Guidelines for further context before offering any responses.

## Definitions:

- **Circuit Segment**: a circuit segment refers to a specific portion of an electrical circuit that can be separated or disconnected from the rest of the system without affecting the operation of other parts of the network. This isolation is typically achieved using switches, circuit breakers, or other control mechanisms.[1]
- **Confirmed Project**: an Undergrounding Project that has completed Screen 3 (Project Risk Analysis), defined below.
- **Confirmed Project Polygon**: 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.
- **Investor Owned Utility (IOU)**: Utility regulated by the Commission that seeks SB 884cost recovery or submits an SB 884 Application or seeks OEIS approval for an SB 884 Plan.
- **Office of Energy Infrastructure (OEIS) Guidelines**: explained in "Instructions," above.
- **Plan Mitigation Objective**: the amount of change in risk (wildfire and reliability) that is necessary to meet the requirements contained in section 8388.5(d)(2).
- **Project-Level Standard**: the Risk Reduction Project Standard, the Reliability Increase Project Standard, and the Tail Risk Mitigation Project Standard.
- **Protective Equipment and Device Settings (PEDS)**: advanced safety settingsimplemented by electric IOUs on electric utility powerlines to reduce wildfire risk.[2]
- **Retired pole**: An electric pole that has been removed from ratebase.
- **Screen 2 (Project Information and Alternative Mitigation Comparison)**: confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to alternative mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.[3]

[1] This concept refers to the same concept found within the OEIS Guidelines Appendix A
[2] For details see https://www.cpuc.ca.gov/industries-and-topics/wildfires/protective-equipment-device-settings
[3] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.4 at 16-17

- **Screen 3 (Project Risk Analysis)**: the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process.[4]
- **Screen 4 (Project Prioritization):** the Electrical Undergrounding Plan (EUP) must set forth a means of prioritization and its definition for each of the factors in section 8388.5(c)(2), i.e. wildfire risk reduction, public safety, cost efficiency and reliability benefits.[5]
- **Topped poles**: the process during an undergrounding project of cutting the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried.
- **Undergrounding Project**: an Eligible Circuit Segment that has completed Screen 2 including the CPUC Data Appendix 1 information completed.

## A. Results of Operation (RO) Model

**Background:**

The Commission requires IOUs seeking rate increases to reflect the results of their requests in what are called results of operation models ("RO models"). An RO model ~~may illustrate~~calculates revenue requirements ~~rate impacts~~ across all of the IOU's lines of business~~, such as in a General Rate Case (GRC), or it may model revenue impacts for a particular program in a "mini RO model." Both models present the utility's forecasted revenue requirement for its operations.~~ ~~The forecasted revenue requirement is calculated through a computer model called the RO model.~~ The major components of the GRC RO model include:

- Rate Base
  - Includes information related to Utility Plant, Working Capital, Customer Advances,Customer Deposits, and Depreciation Reserve;
- Return on Rate Base;
- Taxes;
- Other Operating Revenues and the Rate Base component.[6]

The Commission stated in Decision (D.) 00-07-050 that RO models should be user-friendly and facilitate the Commission's ability to quickly calculate the revenue requirement for various decision scenarios and should easily be able to accomplish the following:

- Change depreciation rates;
- Move unbundled cost categories (UCCs) between major functional groups (i.e., distribution, generation, etc.);
- Calculate the lead-lag portion of working cash;
- Calculate all taxes and tax depreciation;
- Make plant adjustments, including adjustments to beginning-of-year plant; and
- Calculate a distribution Revenue Requirement and Summary of Earnings.[7]

Standalone RO models are used to generate cost recovery requests in Applications to the Commission outside of General Rate Case (GRC) Proceedings. ~~The Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) standalone RO model approach is completely integrated within their the main GRC RO model. SCE has used this integrated RO model approach to generate revenue requests in, for instance, a recent application to recover costs related to wildfire mitigation, vegetation management,~~

**Commented [RH1]:** SDG&E and SCG do not have UCCs.

**Commented [RH2]:** SDG&E uses the GRC RO model and an internal process to quantify program specific revenue requirements embedded in the total authorized revenue requirement. There is no integration of models as there is only one GRC RO model that is used.

[4] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.5 at 17
[5] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.6 at 18
[6] For an example of how this is discussed in a GRC Decision see D.20-12-005 at 334-335.
[7] See D.00-07-050 at 11.

~~catastrophic events, and wildfire liability insurance.[8] In the context of wildfire mitigation investments, SDG&E has not filed a standalone cost recovery application.~~

PG&E utilizes what it calls a mini-RO model to generate revenue requests. This mini-RO model is distinct and separate from the main RO model that PG&E uses in its GRC Applications. In the context of wildfire mitigation investments, PG&E has used this mini-RO model approach in its 2023 cost recovery Application related to wildfire and gas safety.[9] Commission Staff understands that PG&E intends to use the mini-RO model approach to generate revenue requests for SB-884 Applications. According to PG&E, a mini-RO model is distinct from the RO models submitted to the GRC in the following ways:

- The standard mini-RO Model may be tailored for a separately funded/incremental rate case for specific types of costs and applicable income tax rules.
- The mini-RO Models used in separately funded/incremental proceedings cover a proposed revenue recovery period.
- All inputs and revenue requirement calculations are integrated within a single Excel model for simplicity and efficiency.[10]

**Questions:**

1. Should a standalone RO model be used for generating a revenue requirement for an SB-884 application, or is another approach more appropriate? How should each of the IOUs' approaches be harmonized to have one standard for ratemaking in this process? In your response, discuss the need to encourage transparency and stakeholder holder engagement to ensure that rate impacts are incremental to other funding granted to the IOU, accurately represented and litigated in the process of generating a revenue requirement.

2. Is the mini-RO model approach appropriate for generating revenue requests in anSB-884 Application? Why or why not?

3. Is the integrated RO model approach appropriate for generating revenue requests in an SB-884 Application? Why or why not?

4. Through data requests, PG&E has informed Commission Staff that PG&E's mini-RO model does not account for depreciation costs associated with topped poles.[11] These factors would be accounted for in PG&E's GRC RO model. According to PG&E, each of its GRC Applications includes a depreciation study which determines the depreciation rates and is the proper route to account for topped and retired poles. With the mini-RO model being distinct and separate from the main GRC RO model, what challenges might this create for ensuring that the depreciation costs of topped poles is properly accounted for within a utility's rate base? How should these challenges be addressed in the SB-884 Guidelines?

5. Assume that a Commission Decision on a utility's SB-884 Application approves Project A to underground 1 mile of overhead (OH) line that is still in the utility's ratebase.[12] In a future GRC

[8] A.24-04-005
[9] A.23-06-008
[10] PG&E response to data request EUP_DR_SPD_011_Q001-012 at 1-2
[11] Topped poles refers to the process during an undergrounding project of cutting of the top of a pole so that the communication companies can continue using the pole even after the overhead conductor has been buried. See PG&E response to data request DRU14160_Case_EUP_DR_SPD_008, Question 1 at 1.
[12] A utility's rate base is the investment upon which the utility can earn its rate of return.

Application Proceeding, how would the Commission determine that the utililty had appropriately removed the 1 mile of OH line from the ratebase if the SB-884 Application was based on the mini-RO model?

6. PG&E has informed Commission Staff that it does not submit a depreciation study as testimony in an Application where the revenue request is generated by a mini-RO model. Should the Commission require a utility to submit a depreciation study along with an SB-884 Application? If so, should the utility be required to update certain parts of the depreciation study submitted with the utility's most recent GRC, such as that related to grid hardening and other wildfire mitigations? Explain your answer.

## B. Third Party Funding

1. How should the IOUs account for third-party funding they seek or receive, as required by Public Utilities Code Section 8388.5(j), for undergrounding projects to ensure the requirements of the Commission's SB-884 Guidelines and Senate Bill (SB) 884 are met?

    a. How should ratepayer savings attributable to third party funding be accounted for?
        i. Should they appear as an offset to the proposed revenue requirement in a mini-RO model?
        ii. Should they appear in the IOU's next GRC?
        iii. Should there be a reporting requirement for the utilities to report on third-party funding? If so, what information should be included in this report?

    b. Should the IOUs treat third-party funded plants as contributed plants? Why and why not?

    c. Describe the IOUs' accounting for third-party funded plants in regards to utility plant accounts, and depreciation and amortization reserves.

2. Should an IOU file an advice letter documenting which annual cost caps are reduced by third-party funding? If so, how often should it be filed and what should the advice letter include?

## C. CBR Threshold

**Background:**

The Cost-Benefit Ratio (CBR) is described in D.24-05-064 and D.22-12-027 of Rulemaking (R.) 20-07-013. CBR is a financial metric used to evaluate the efficiency of a project by comparing the benefits it offers (in this case, wildfire risk reduction and reliability enhancement) to its associated costs (cost of undergrounding overhead lines). The greater a CBR is relative to 1.0, the more its benefits outweigh its costs. Thus, as an illustrative example, a project with a CBR of 7.0 has benefits that exceed its costs by seven times, whereas a project with a CBR of 1.0 means costs and benefits are equal, and a project with a CBR of less than 1.0 means that its costs exceed its benefits. If an IOU were allowed to deploy a project with a CBR less than 1.0, it could be due to operational constraints. For example, in order to complete a project, the IOU may be required to perform work on other circuits segments upstream or downstream from the circuit segment with a high CBR. Those upstream or downstream circuit segments may have low CBRs even though they are necessary to the project, and therefore they may bring down the total CBR of a project. Sometimes projects with a CBR of 1.0 or below would be proposed because they are associated with high-risk overhead lines that face constraints such as operational considerations or legal statutes.[13]

**Questions:**

1. Should IOUs be required to provide additional justifications when they want to install projects that have either:

    a. Low CBRs[14] (in comparison to other UG projects in that IOU's application);

    b. CBRs below 1.0; or

    c. Lower CBRs compared to the CBRs of alternative wildfire mitigations that do not include undergrounding (such as covered conductor, remote fault detection technologies or high impedance fault detection)?

        i. And in each case (for Questions (1) (a)-(c) above) where the answer is yes, please explain why and what those additional justifications might be.

        ii. Furthermore, if the 1.0 threshold referenced in question (1)(b) above is too low from your perspective, and if IOUs should therefore be required to provide additional justifications when they want to install projects that have CBR thresholds greater than 1.0, then at what threshold above 1.0 should the additional justifications no longer be necessary and why?

## D. Audit

**Background:**

The Commission's SB-884 Guidelines require that costs submitted in an SB-884 Application meet certain conditions (Phase 2 Conditions) in order for Commission to authorize the recovery of those costs via a one-way balancing account.[15] That one-way balancing account is subject to audit. If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. The details of this audit, including who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a later decision or order.

**Questions:**

1. Please expand on what the main objectives of the audit should be, in addition to ensuring the Phase 2 Conditions have been met?

---

[13] Associated circuit segments refer to the high-risk circuit segments which might be the primary reason to hardening the Low CBR circuit in the first place.
[14] "Low CBR" can be defined as projects whose CBRs are below a certain threshold (e.g., 2 standard deviations, where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average CBRs of other projects offering the same type of mitigation.
[15] The Phase 2 Conditions will include, but are not limited to, a total annual cost cap, two-year rolling average recorded unit cost cap, two-year rolling average recorded CBR threshold, and applying third-party funding to reduce the cost cap. For details see SPD-15, SB-884 Program: CPUC Guidelines at 10-11.

a. What language will best ensure that the audit achieves its various goals, including determining whether the costs booked to the balancing account meet the Phase 2 Conditions?

b. Are the specific conditions and other criteria for the audit clearly outlined in the Commission's SB-884 Guidelines to help determine whether costs in question meet such criteria?

c. Should audit objectives include verifying that claimed IOU activities and projects have been completed as claimed?
    i. Would satellite imagery or other photographic evidence be sufficient to perform this verification?

d. What are the project characteristics (e.g. projects with low CBR) that the audit should address?
    i. Should the CBR stated in the Application be verified during the audit?

e. Should the auditor be required to follow professional auditing standards to meet the audit objectives; and if so, which ones?

2. In D.23-02-017, the Commission explained that costs are incremental if "in addition to completing the planned work that underlies the authorized costs, the utility had to procure additional resources, be they in labor or materials, to complete the new activity. The existence and completion of a new activity by itself does not prove the cost was incremental."[16]

    a. With this Decision in mind, how should the Guidelines ensure that the scope of the audit addresses whether the costs in an SB-884 Application are incremental to other revenue requests presented to the Commission in a GRC or other cost recovery application? Please provide suggested language.

    b. Should an IOU be required to present costs related to straight time labor, overtime labor, contracted labor or other labor-related costs in its showing of incrementality in an SB-884 Application?

    c. Should audit Guidelines address the issue of incrementality between the Balancing Account and Memo Account authorized in Resolution SPD-15 and established through a utility's SB-884 Application? If so, what language would you recommend?

    d. Should an IOU be required to document its methodology of tracking incremental costs?
        i. Should all IOUs be required to use consistent methodologies in tracking these incremental costs?
        ii. Should an IOU be required to document how the GRC-approved cost categories line up with account categories or projects claimed to provide support for its methodology of tracking incremental costs?

3. When should the audit of the balancing account occur?

    a. Should the audit begin after the Commission adopts a Decision in the utility's GRC Application proceeding; if so, when?

4. How often should the audit of the balancing account occur?

[16] D.23-02-017 at 27.

a. Should an audit of the balancing account be limited to once every four years to correspond with the GRC cycle?

b. If an audit of the balancing account should occur multiple times in a GRC cycle, explain how many times and the rationale for requiring multiple audits within a utility's GRC cycle?

5. The Commission's SB-884 Guidelines state that if the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund to ratepayers.

   a. Should language be added to the SB-884 Guidelines that explicitly describes the method for a refund, such as a true-up in the utility's rates after the audit has been completed? If yes, provide suggested language along with a justification. If no, explain why.

6. The Commission's SB-884 Guidelines require the utility to identify any wildfire mitigation cost savings in its Application.[17] How should the claim of cost savings be addressed by the audit?

7. Should the Commission consider other possible audits completed previously by either third parties or internal IOU auditors as part of the assessment in determining appropriateness and reasonableness of claimed costs in question?

## E. Net Present Value (NPV) Calculations and Sensitivity Analyses

**Background:**

**NPV Costs and Revenue Requirement**
Because undergrounding projects take a long time to complete and have long useful lives, their CBRs are calculated in present day dollars, even if the cost will be much higher in the future. This calculation is called the NPV of costs from the revenue requirement and involves discounting future revenue requirements (which represent the utility's future costs) to their present value. Utilities need to identify and report the future revenue requirements: these are the yearly costs the utility expects to recover from ratepayers, typically including operational expenses, capital expenditures, and a return on investment. Utilities need to determine and report the discount rate(s) representing the time value of money and how NPV costs are calculated.

**Sensitivity Analyses**
A sensitivity analysis is a technique used to understand how different inputs into a model impact the outcome or results. For example, sensitivity analysis is often used in arriving at a CBR and shows how sensitive the projected costs, benefits or risks are to changes in the input assumptions.

**AB 2847**
Assembly Bill (AB) 2847 (Stats. 2024, Ch. 578) requires the following:

> Pub. Util. Code Section 739.15(a) The commission shall determine in a scoping ruling or other ruling whether an application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures requires the estimates described in subdivision (b).
>
> (b) An application from an electrical corporation or gas corporation requesting authorization for or recovery of capital expenditures, including an application for conditional approval of the costs of an undergrounding plan pursuant to Section 8388.5, shall include, if the commission pursuant to

[17] For details see SPD-15, SB-884 Program: CPUC Guidelines at 7.

subdivision (a) determines that the estimates are required, the electrical corporation's or gas corporation's best estimate of both of the following:

(1) The application's impact on the electrical corporation's or gas corporation's annual revenue requirement for each year that the capital expenditures described in the application are expected to remain in the application's rate base if the application is approved or conditionally approved.

(2) The net present value of the application's impact on the electrical corporation's or gas corporation's annual revenue requirement provided pursuant to paragraph (1).

(c) The commission shall require the electrical corporation or gas corporation to provide supporting workpapers and calculations for the estimates described in subdivision (b).[18]

**Questions:**

1. In the context of AB 2847, should the utilities calculate and report their revenue requirement and NPVs costs in an SB-884 Application using a consistent method across IOUs? Explain your answer.

2. Considering the D.24-05-064 requirement that the IOUs present the results of three discount rate scenarios for their CBR calculation,[19] should the utilities be required to present NPV Benefits, NPV Costs, and CBR using each of the three discount rates in their SB-884 Applications?

3. Given that different mitigation projects may start at different times and become used and useful[20] in different years, how should the utility incorporate these differing timeframes into the calculation of NPV Costs and NPV Benefits?

4. Should the Commission require IOUs to report and compare NPV Costs and NPV Benefits, and CBR of undergrounding in a consistent mannner across IOUs?

   a. Do the current Commission SB-884 Guidelines allow for consistent comparison between undergrounding projects and alternatives? If yes, explain why. If not, why not?

   b. Do the current Commission Guidelines allow for accurate comparison between undergrounding projects and alternatives? Explain your answer.

## F. Changes to a Utility's Expedited Undergrounding Plan

**Background:**

OEIS' revised Electrical Undergrounding Plan (EUP) guidelines allow for changes to the IOU's undergrounding Plans to occur throughout the ten year time period of any particular Plan. For example, Guideline 2.7.5.2 provides that model version changes are "qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a backtest report (see Section 2.7.6 )." OEIS defines "calibration changes" as "smaller changes that do not significantly impact the Model Risk Landscape and

[18] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB2847

[19] See D.24-05-064 at 102-105. The utilities are required to calculate CBR for each mitigation using three discount rate scenarios: a) Societal Discount Rate Scenario, b) Weighted-Average Cost of Capital Discount Rate Scenario, and c) Hybrid Discount Rate Scenario.

[20] The used and useful year of a project is the year that the project is completed and energized.

only require the establishment of a new Baseline."[21] In Section 2.4.2.4 of the OEIS Guidelines, a Confirmed Project is defined by the boundaries of the Confirmed Project Polygon that encompasses the entire Circuit Segment on which the Undergrounding Project is defined.[22] If an IOU changes its project, the polygon (or other illustration of where and how the undergrounding project will occur) is not updated. However, the OEIS Guidelines in Section 2.3.4 also state that if the scope of a project changes to include sections outside of the Confirmed Project Polygon (e.g., if a portion of another Circuit Segment outside of the approved Confirmed Project Polygon is added to a project), the utility can calculate risk reduction by using the risk reduction for "the full (expanded) project" for determining the contribution towards the Plan Mitigation Objective, and yet the utility may only use "the work inside the original Confirmed Project Polygon" for determining whether the project meets the Project-Level Standard. Hence, cost and risk reduction calculations, that will provide the substantial factual basis from which the Commission will deliberate on to make its Phase 2 Decision, may be impacted by potential changes to the scope of projects after a Phase 2 Decision is issued.

**Questions:**

1. How should the Commission ensure and evaluate that the costs, risk reduction, and CBR of a project are accurately calculated when portions of Circuit Segments are added or modified after:

    a. an IOU submits an SB-884 Application to the CPUC?

        i. If an IOU changes its projects after obtaining OEIS approval of its EUP, how should the utility incorporate these changes in its Application for cost recovery at the CPUC?

    b. the CPUC adopts a Phase 2 Decision on an SB-884 Application?

        i. If an IOU changes a project after the adoption of a Phase 2 Decision, for example due to circuit expansion, risk model change, or operational constraints, how should any additional costs, or cost reductions, be accounted for? Explain your answer.

        ii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC require an IOU to report changes to the project's CBRs? Should there be a threshold over which CBR changes should be reported?

        iii. If an IOU changes a project after the adoption of a Phase 2 Decision, how should the CPUC address projects that no longer meet the the conditional approval stipulated in the Phase 2 Decision?

    c. an audit of the SB-884 Application has concluded?

    d. an IOU submits an Application for a just and reasonableness review of its SB-884 Memorandum Account?

[21] See OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.5.2 at 36.
[22] OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

2. Considering the implications of OEIS Guidelines Section 2.3.4 described above, when the utility calculates CBRs, should the utility use the NPV Benefits calculated for the risk reduction from:

   a. "the full (expanded) project"? Why or why not?

   b. "the work inside the original Confirmed Project Polygon"? Why or why not?

   c. Would your answers to 2a. and 2b. depend on circumstances, such as when the CBR is calculated? Please describe the circumstance and explain why it would affect the answer to 2a. and 2b

3. There are limits on Commission staff's ability to make changes to a Commission Decision or Resolution pursuant to delegated authority. D.02-02-049 and GO 96-B Rule 7.6.1 describe the difference between discretionary and ministerial action.[23]

   a. If an IOU seeks to change an undergrounding project, is there any change that you believe could be deemed ministerial with approval delegated to staff? If so, describe such ministerial changes.

   b. If an IOU seeks to change an undergrounding project is it your view that a Petition for Modification (PFM) is required?[24] Does your answer depend on the type of change? If so, please explain .

4. The current OEIS guidelines allows for a Confirmed Project to change within the 10-year period of the EUP.[25] How should the Commission address an undergrounding project where the trench length exceeds the forecasted estimate submitted to the Commission in an SB-884 Application?

   a. Should there be a trench length excedence threshold that:
      i. requires the project to be audited? Explain your answer.
      ii. triggers a PFM requirement? Explain your answer.

   b. What data could be used to determine whether or not the excedence threshold has been surpassed?
      i. Would the data collected through the OEIS Guidelines be sufficient? Why or why not?

5. Are the model version changes and calibration changes described in OEIS Guidelines 2.7.5.2 relevant to how the CPUC should handle undergrounding plan changes? Explain your position.

   a. How, if at all, should an IOU report to the CPUC and stakeholders on updates to a model, including the Outage Program Risk model described in Section 2.7 of the OEIS SB-884 Guidelines,[26] which are still in development and not submitted or approved as part of an IOU's Wildfire Mititgation Plan (WMP)?

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[23] While discretionary and ministerial actions vary based on the subject matter, they broadly mean the following. Ministerial actions are actions which are made based on pre-defined criteria. These actions can be carried out by Industry Divisions, such as Safety Policy Division and Energy Division. Agencies cannot delegate discretionary action without statutory authority.

[24] PFMs asks the Commission to make changes to an issued decision. See CPUC Rules of Practice and Procedure Rule 16.4.

[25] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.4.2.4 at 13.

[26] For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7 at 24-41.

6. TURN stated in its May 29, 2024 comments on the OEIS Draft Guidelines that changes of at least 20% of circuits included in the EUP should trigger a new comment period of 10-15 days.[27] Cal Advocates similarly stated in its August 9, 2024 comments on PG&E's topics for Discussion of Revised Draft Guidelines that at each semiannual progress report new thresholds and risk models be used to re-evaluate the cost-effectiveness of projects in the current EUP work plan, to ensure that the thresholds are meaningful and the project prioritization evolves to reflect current information.[28]

    a. State your position on these comments.

## G. How to Address Circuit Segments and Project Polygons

**Background:**

Section 2.8.1 of the OEIS Guidelines requires IOUs to furnish updated tabular data with each Progress Report. Section 2.8.3 of the OEIS Guidelines requires IOUs to furnish updated information reported in geodatabase submissions in each Progress Report including the latest version of their projects in polygon form. Section 2.7.6 of the OEIS Guidelines require the IOUs to retain models and calibrations data for the lifetime of the program, but the OEIS Guidelines do not have an explicit retention policy regarding tabular data and geodatabase submission updates.

**Questions:**

1. Should the CPUC Guidelines include an explicit retention policy that requires the utilities to retain updates to the tabular data and geodatabase with each Progress Report for the lifetime of the program?

2. Should the polygons be updated after the Commission adopts a Decision on the utility's application? Why or why not?

## H. Number of Alternatives

**Background:**

Undergrounding refers to the practice of placing utility infrastructure, such as power lines, underground instead of using overhead poles and wires. Covered conductor refers to overhead lines encased with material thick enough to reduce the likelihood of sparks or faults, which in turn reduces the likelihood of causing fires or outages. Protection devices are switches, reclosers or sectionalizers installed on overhead power lines to isolate faults or shut off power, minimizing the scope and impact of outages or incidents. Other mitigations include, but are not limited to, practices such as vegetation management, which involves trimming or removing vegetation near power lines, and pole enhancements such as stronger, more fire-resistant materials (e.g., steel poles instead of wooden poles).

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[27] See TURN Opening Comments on Draft 10-Year Electrical Undergrounding Plans Guidelines, May 29 2024 at 3 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56734&shareable=true

[28] See Corrected Comments of the Public Advocates Office on Pacific Gas and Electric Company's Topics for Discussion on Revised Draft EUP Guidelines, August 9 2024 at 2 https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57175&shareable=true

The OEIS guidelines require an IOU to compare two alternative mitigations.[29] An alternative to this approach is the idea of requiring utilities to present an "exhaustive list" of all possible mitigations, which could offer more comprehensive risk analysis but may be resource intensive.

**Questions:**

1. Should the CPUC limit alternatives to those required by OEIS, or should it require additional mitigation alternatives to be presented? Explain your answer.

2. Should the CPUC allow utilities to tailor the number of alternatives analyzed based on specific circumstances, such as regional risks, or should a standard approach for all projects be required? Explain your answer.

3. How can the CPUC ensure that the analysis of alternative mitigations clearly, comprehensively and accurately compares costs and benefits of undergrounding, covered conductor, protection devices, and other mitigations?

4. Are there standards or regulations the CPUC should consider requiring for IOU projects and altenative mitigations, similar to Australia's Electricity Safety Bushfire Mitigation Regulations 2017[30]?

## I. Compliance with the Application

1. If a project does not adhere to the timeline for completion included in its Application to the Commission, how should the Commission address this delay, and should delay affect cost recovery for that project?

## J. How to Address Costs if an Application or Projects are Rejected or Abandoned

1. Undergrounding preparation costs could include permitting, site or right of way acquisition, labor/hiring, planning, environmental review and other operational costs incurred in planning an undergrounding project. What is your view on how the Commission should treat undergrounding preparation costs if the undergrounding project is not carried out and/or completed?

2. Does your answer to Question J.1 depend on why the project was not carried out and/or completed? For instance:

    a. Project denied by OEIS;

    b. Project funding disapproved by CPUC;

[29] Alternative Mitigation 1 must include covered conductor in combination with some type of PEDS. Alternative Mitigation 2 must include one other mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1, including but not limited to remote fault detection technologies and high impedance fault detection. For details see OEIS REVISED DRAFT 10-Year Electrical Undergrounding Plan Guidelines, Section 2.7.10 at 41.
[30] Electricity Safety (Bushfire Mitigation Duties) Regulations 2017 (legislation.vic.gov.au). These Regulations set guidelines and standards for protective devices' performance (e.g., how fast switches should close and reduce voltage on a faulted line) and for other mitigation measures.

c. Project abandoned by IOU;or

d. New legislation prevents the project from being carried out.

3. Generally, costs incurred prior to plant being placed in service and deemed used and useful are recorded as Allowance for Funds Used During Construction (AFUDC) costs. AFUDC is typically used for projects that are expected to be constructed and be placed into rate base so they can earn a rate of return.

   a. Should SB 884 undergrounding costs be treated as AFUDC if a project is rejected by OEIS or cost recovery for the project is denied by the CPUC?

   b. Should AFUDC costs related to a project that is rejected, denied or abandoned be recovered in an IOU's General Rate Case or should the CPUC solely determine cost recovery for costs of projects that are not yet completed in SB 884 project applications?

   c. How should IOUs record costs related to projects that are in progress but not yet completed to avoid retroactive ratemaking?[31] IOUs responding shall specify in which account they plan to record pre-Application costs and how they propose to seek cost recovery for those costs if a project is rejected, denied or abandoned.

4. Should the CPUC impose a requirement that if an SB-884 project reaches a certain stage it needs to be completed? Explain your answer.

5. Should the Commission develop guidelines pertinent to abandoned projects (i.e., projects the IOU opts not to complete or use)? If so, what positions should the guidelines take?

   a. Should any relate to cost recovery; and if so what positions should they take?

   b. Should any relate to removal of facilities; and if so what positions should they take?

   c. What other guidelines should there be?

6. Should the CPUC impose a requirement that a project that has remained at a particular stage for more than a certain period should be reported as abandoned?

   a. If so, what should the CPUC require regarding cost recovery and other activity on that project?

   b. If so, at what stage(s) of the project should it be reported as abandoned? How much time should elapse within that stage for the CPUC to require the utility to report the project as abandoned?

   c. If not, why not?

7. New Jersey has a rule that relates to cost recovery for abandoned projects that were part of an accelerated level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing, critical water distribution components that enhance safety, reliability, water quality, system flows and pressure, and/or conservation.

   The rule states:

[31] Rates are set on the cost of doing business which the utility files in a rate case. The resulting Decision of the rate case is applied going forward and is never retroactive.

If within three years after the effective date of a Foundational Filing, a water utility has not filed a petition in accordance with the Board's rules for the setting of its base rates, all interim charges collected under the DSIC rate shall be deemed an over-recovery, and shall be credited to customers in accordance with this subchapter. A water utility may seek recovery of such projects in the ordinary course through its next base rate case. Notwithstanding the above, a water utility may continue to collect a DSIC charge during a pending rate case filed in accordance with this section.[32]

a. Should the CPUC develop a similar requirement for SB 884 undergrounding projects? Explain your answer.

[32] New Jersey Administrative Code 14:9-10.4 (e) - DSIC Foundational Filing https://casetext.com/regulation/new-jersey-administrative-code/title-14-public-utilities/chapter-9-water-and-wastewater/subchapter-10-distribution-system-improvement-charge/section-149-104-dsic-foundational-filing

**INFORMAL COMMENTS OF THE UTILITY REFORM NETWORK (TURN)**
**IN RESPONSE TO OCTOBER 14, 2024 QUESTIONS**
**FROM CPUC STAFF REGARDING SB 884 IMPLEMENTATION**

**November 12, 2024**

## 1. Introduction

The Utility Reform Network (TURN) submits these comments in response to the October 14, 2024 questions circulated by the Commission's Safety Policy Division (SPD) related to the CPUC's implementation of SB 884.

TURN appreciates the thoroughness and thoughtfulness of SPD's questions and that SPD is providing an open and transparent opportunity for all interested parties to answer these questions simultaneously. These comments reflect TURN's best efforts to respond to these important questions.

However, it should be understood that time and resource constraints limit TURN's ability to answer every question with as much detail as we would like. In addition, because it is not clear that this question and answer process will contribute to a Commission decision that is eligible for intervenor compensation, TURN has not been able to retain an outside consultant to help with responding to the questions. Furthermore, TURN does not have the benefit of knowing the nature of the utility's plans for SB 884 applications and does not have a dedicated staff who can devote most or all of their time to thinking through issues and contingencies that may arise in the SB 884 process and the detailed mechanics of SB 884 implementation. For all of these reasons, TURN's responses below should be considered preliminary and subject to change as TURN gains a more detailed understanding of the utility requests and positions.[1]

## 2. Section C – CBR Threshold

### 2.1. When Utilities Should Be Required to Provide Additional Justification for Projects

Utilities should be required to provide additional justification for projects in at least two situations (SPD Question 1).

The first is when the undergrounding project CBR for a given location is less than the CBR of one or more alternative projects to address the risk at that location. (See Section H – Number of Alternatives below). Undergrounding is the most expensive alternative, one that increases utility rate base. Thus, utilities have a financial incentive to choose undergrounding over other more reasonable alternatives – one that needs to be kept in check by the CPUC's duty to ensure just and

[1] For these reasons, TURN is not able to respond to questions in certain sections of SPD's document. The questions in Section A, regarding RO models and depreciation, are one example of questions that require the expertise of an outside consultant and would benefit from being presented in a process that is certain to contribute to a Commission decision that is eligible for intervenor compensation.

reasonable rates.[2] Thus, in the Phase 2 review process,[3] the Commission has an obligation to ensure that, for each proposed project location, undergrounding is the most reasonable alternative. The CBR is an important measure of one of the key elements of reasonableness, cost-effectiveness. The CBR is designed to comprehensively measure all relevant benefits of risk mitigation projects in the numerator and all relevant costs in the denominator. Thus, when the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the utility should be required to make the case for why the undergrounding solution is still the most reasonable solution.

When the undergrounding CBR is less than or equal to the CBR of one or more operationally feasible alternatives, the fundamental showing the utility needs to make is why, notwithstanding this situation, the Commission should still approve the project in question. A key showing should be why the CBR, as calculated, is not sufficiently accounting for the benefits of undergrounding compared to the other alternatives for this particular location – what important factors is the CBR calculation missing or not correctly valuing? Are there risk characteristics of the location that the CBR is not sufficiently capturing or is the calculation of risk mitigation benefits of the competing alternatives not accurate in a way that undervalues undergrounding for some reason? If so, the utility needs to explain in detail why the CBR results should not be relied upon.

The second situation in which a utility should be required to provide additional justification for a proposed undergrounding project is when the CBR of the project is below a CBR threshold. It is premature to specify this threshold now. The threshold should be one of the issues determined in Phase 2, based on the CBR information submitted with the Phase 2 application. As discussed below in this section, experience has shown that utilities have different ways of calculating RSEs and the same is likely to be true for CBRs, notwithstanding Commission efforts to the contrary. For example, if utilities use different scaling functions or have different ways of addressing tail risk in their calculations, the CBR values for the same activity could differ significantly.

Once the Commission sets this threshold, which should be an early determination in the Phase 2 proceeding, the utility should be required to submit a justification for any project that falls below the threshold. The showing should again be the utility's explanation of why the CBR is not an accurate reflection of the cost-effectiveness of the project in question and why, notwithstanding the low CBR, the project should still be approved.

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[2] PU Code Sections 451, 8388.5(e)(6).

[3] These comments use the Phase 1, Phase 2, and Phase 3 nomenclature, as those Phases are defined in SPD-15.

### 2.2. Robust Scrutiny of the Utility's CBR Calculations and Methodology is Necessary

As SPD knows, CBRs (and their predecessor, RSEs) are complex calculations based on complex methodologies. When determined in accordance with Commission requirements and otherwise using reasonable inputs and assumptions, they provide extremely valuable information regarding the cost-effectiveness of proposed projects and competing alternatives. However, because of their complexity, utilities also have the ability to skew the calculations in favor of their preferred outcomes. Potentially controversial elements of CBRs include, but are not limited to: whether the utility is accurately reflecting the mitigation effectiveness of competing alternatives;[4] whether the utility is using accurate costs for competing mitigations;[5] whether the utility's analysis is sufficiently granular to take into account the specific risk factors and costs at a given location; whether the utility is using reasonable values for the cost of electric reliability consequences;[6] whether the utility is reasonably valuing property damage from wildfires;[7] whether the utility is correctly modeling the impact of climate change on the wildfire risk;[8] whether the utility is correctly valuing safety consequences;[9] the reliability of CBR results based on a risk-averse scaling function as compared to a risk-neutral scaling function in the circumstances under consideration; [10] and the discount rate used to determine present values of the costs and benefits.[11]

Because of this complexity and opportunity for utility-calculated CBRs to reflect the companies' financial interest rather than the public interest, the CPUC needs to require the Phase 2 application to include comprehensive workpapers explaining the CBR calculation methodology and documenting the inputs, assumptions, and calculations.[12] If a utility has recently provided such workpapers in other submissions, the utility could provide those same workpapers but would

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[4] In GRCs, intervenors have found that certain utilities understate the mitigation effectiveness of covered conductor based alternatives, including REFCL and other enhancements to covered conductor, compared to undergrounding.

[5] In GRCs, TURN has found that certain utilities overstate the relative cost of covered conductor based alternatives compared to undergrounding.

[6] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 3, criticizing PG&E's method and noting that it inflates wildfire mitigation benefits.

[7] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 56.

[8] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 53.

[9] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, TURN's Informal Comments attached as Attachment 5, pp. 5-7.

[10] See SPD's 11/8/24 Evaluation Report on PG&E's RAMP, A.24-05-008, p. 4.

[11] See Section 8 below, responding to SPD's Section E questions.

[12] SPD-15, Attachment 1, p. 7.

need to clearly identify and explain any material changes. An application that fails to provide complete CBR workpapers should be rejected and a resubmission required.[13]

### 3. Section H – Number of Alternatives

The Commission should not limit the alternatives presented and considered to those required by OEIS (SPD Question 1). The Commission, not OEIS, has the obligation to ensure that any plan approved in Phase 2 meets the just and reasonable standard. Ensuring that each undergrounding project is needed and superior to all other alternatives is essential to meeting that standard. In addition to the alternatives noted in the preface to the SPD questions for this item, the alternatives should include remote grids and EPSS/PSPS. In some locations, it may be far less expensive to use a combination of EPSS/PSPS and utility-supplied off-grid back-up power than undergrounding.

As discussed in Section 2 above, the utility should demonstrate for each project that undergrounding is the most reasonable alternative for that location. The alternative that utilities are required to compare should include all operationally feasible options for the location. When considering covered conductor, all operationally feasible enhancements to covered conductor, such as REFCL, Fast Curve, EPSS, and other current-limiting technologies should also be considered as a menu of options, each with different effectiveness and cost attributes. If an alternative is not feasible, the utility needs to explain why. Thus, depending on which alternatives are feasible at a location, the alternatives considered may vary by location (SPD Question 2).

For TURN's response to SPD's question 3, see Section 2 above regarding how CBR should be used in the comparison of alternatives, including the need for detailed workpapers showing how the CBR was calculated, which should include comprehensive information about costs and benefits.

### 4. Section D – Audit

#### 4.1. Preliminary Matters

The inclusion of an "audit" in the CPUC's process was a change to draft SPD-15 in response to comments. As a result, parties have not been given an opportunity to comment on that change. TURN appreciates the opportunity to address at least some of TURN's concerns with that aspect of SPD-15 here.

As a preliminary matter, TURN continues to take the position that the statute requires an *up-front* determination, *before cost recovery is authorized*, that the recorded costs are just and reasonable, including satisfying the Phase 2 conditions.[14] TURN's comments here do not waive

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[13] *Id.*, p. 5.

[14] See TURN's 12/28/23 Comments on Draft SPD-15, pp. 3-5.

that legal contention but will assume, solely for purposes of discussion, that the CPUC can successfully defend its legal position.

As another preliminary matter, TURN notes its concern with the vague and inapposite term "audit." As will be discussed in this section, what SPD-15 describes as an "audit" needs to be a CPUC decision-making process – a post-implementation review -- that allows full participation by intervenors and results in an appealable decision made by the CPUC, not Staff. The necessary review cannot simply be outsourced to an "auditor" who makes the necessary determinations without a meaningful opportunity to participate by all interested parties and a decision by the Commission.[15]

### 4.2. Questions 1 and 5

As identified in SPD-15, a key objective of the review must be to ensure that the conditions of approval have been satisfied. The conditions identified in SPD-15 primarily relate to ratemaking matters that would not likely be within the expertise of a traditional auditor, nor covered by professional auditing standards. Instead, the Commission should use a process that allows meaningful participation by all interested parties (and by CPUC Staff, if the CPUC so chooses) to enable the CPUC to determine whether the information the utility supplies to support satisfaction of each condition is accurate and based on a reasonable methodology with reasonable inputs and assumptions.[16]

To the extent that the utility fails to demonstrate compliance with any of the conditions, costs of implemented projects must be removed from the balancing account as necessary to bring the completed projects into compliance with the conditions. Those costs should not be included in rate base at any point, unless and until the CPUC finds them just and reasonable and appropriate for inclusion in rates.[17]

The CPUC's review process should also assess whether factual contentions on which the Phase 2 approval was predicated proved to be accurate. If recorded costs exceed forecast costs by more than 5% for any project, the utility should be required to show that the change in cost did not change any of the CPUC's findings relating to stand-alone or relative cost-effectiveness (i.e., compared to alternatives) on which the CPUC's approval was based. If the increase in project

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[15] Having noted its concern about the term "audit," TURN will use the term "review" in the remainder of this section.

[16] See Section 2.2 above regarding the need to carefully scrutinize the utility's calculated CBRs.

[17] It is unclear from SPD-15 whether costs that are removed in order to satisfy the Phase 2 conditions are eligible for inclusion in a Phase 3 application. To encourage cost efficiencies by the utility, TURN recommends that such costs not be eligible for recovery through Phase 3.

costs renders those findings invalid, the excess costs should be removed from the balancing account, as discussed in the prior paragraph.

In addition, the review should determine that the recorded costs were spent correctly by examining, among other things, whether: the project was completed as claimed, as supported by satellite imagery; all of the recorded costs directly related to the identified project and are properly treated as a cost of the project (not some other project); the costs were clearly described to demonstrate satisfaction of the foregoing requirements; no duplicate costs were included; if any recovery of cost overheads was allowed in the Phase 2 decision, overheads were properly calculated and reasonable; only categories of costs allowed by the CPUC in its Phase 2 decision are included in the balancing account. In contrast to the SPD-15 approval conditions, these sorts of requirements do not require ratemaking and cost analysis expertise and would benefit from review by a traditional auditor (fully independent of the utility – see Section 4.6 below) under professional auditing standards. The auditor's results should be made available to all interested parties for their comment. All recorded costs that were incorrectly assigned to approved projects must be removed from the balancing account.

The costs for any project that was included in the plan approved in the Phase 2 decision but not performed in the prescribed year should be removed and the price cap for that year reduced by the approved cost of the project. Costs should not be included in the balancing account until a project is complete. As discussed further in Section 7 below, ratepayers should not pay costs for projects that were not completed and are not attributable to a used and useful project.

**It is critical that any previously recovered costs that are removed from the balancing account as a result of this review process (or any other process) be returned to ratepayers.** The removed costs should include interest, to ensure that ratepayers are not made worse off by the time it may take to conclude the review process. The removed costs, plus interest, should be credited to ratepayers in the utility's annual electric true up advice letter.

The CPUC's review process must allow sufficient time and discovery opportunities for interested parties to analyze the utility information and prepare meaningful comments to inform an appealable CPUC decision that is eligible for intervenor compensation. As noted, the intent of the process is to ensure that the recorded costs are just and reasonable and appropriate for recovery in rates. Section 8388.5(e)(6) confirms that the Commission must determine that costs are just and reasonable. Intervenors have a statutory right to participate in ratemaking proceedings to assess whether costs are just and reasonable.[18] Nothing in SB 884 abridges such rights.

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[18] *E.g.,* PU Code Sections 451, 1701.3.

### 4.3. Question 2

The utility should also be required to make the labor and resource incrementality showing cited in question 2. Cal Advocates has focused on this aspect of the incrementality issue in cases seeking recovery of wildfire mitigation costs, so TURN would defer to Cal Advocates on the details of the necessary showing.

If the SB 884 plan period coincides with any period in which a GRC decision has allowed cost recovery for any undergrounding costs, the review process should require an incrementality showing to make sure none of the activities covered by the GRC are included in the SB 884 balancing account recorded costs. GRC cost overruns for activities covered by the GRC authorization should not be considered incremental and should not be included in the balancing account, for reasons TURN has explained in Section 7 of its opening brief in A.23-06-008. [19]

### 4.4. Questions 3 and 4

The review process discussed in this Section should happen at least once per year, after the completion of each year of work authorized in the Phase 2 decision. The review for each year should be limited to only the costs of projects completed in that year, because only those costs should be included in the balancing account. The review after the first year would not be able to review Phase 2 conditions that require two years of recorded data (e.g., Conditions 3 and 4 in SPD-15, Att. 1, p. 11), but would be able to review the other conditions and other matters discussed in this response. The review for the first year of recorded costs should indicate that recovery of year 1 costs remains contingent on satisfaction of conditions 3 and 4 and any other conditions that require more than one year of information.

### 4.5. Question 6

Regarding how any utility claim of cost savings should be addressed by the review process, it is premature to give a definitive answer to that question. The review process may have an important role to play, but the role would likely depend on the nature of the asserted cost savings and whether the costs in question have already been approved for recovery or whether they are costs that have not been the subject of a cost recovery request. In addition, as the SPD-15 Guidelines state, the utility's Phase 2 application must explain the methodology by which the Commission can ensure that all identified savings are passed on to ratepayers. TURN would be better able to offer an answer to this question after first considering the methodology proposed by the utility.

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[19] For a discussion of the type of showing the utility should be required to make to demonstrate incrementality compared to the GRC authorization, see, e.g., TURN's Opening Brief in A.23-06-008, found here, pp. 46-48.

### 4.6. Question 7

To the extent that a traditional auditor is used for any aspects of this review process, the auditor must be either on the CPUC staff or directed exclusively by the CPUC, not by the utility. The review of recorded costs is intended to fulfill the CPUC's obligation to ensure the costs are just and reasonable. As a result, any auditor should be thoroughly independent and overseen solely by the CPUC. Results from utility-retained auditors should not be considered dispositive of any issue in the review process. Prior cases have shown that utility retained auditors have missed key problems with the incrementality and reasonableness of the costs they supposedly audited.[20]

## 5. Section F – Changes to a Utility's Plan[21]

Under SB 884, the plan submitted to the CPUC for its Phase 2 review will be a group of proposed projects with detailed information for each project as required by the statute[22] and by the rules of the two reviewing agencies. The statute allows OEIS to require that this plan be modified,[23] but only the OEIS approved plan can be presented to the CPUC for its review and approval.[24] Thus, the statute does not allow a utility to add any new projects to the plan approved by OEIS or make material changes to projects, as the new or changed projects will not have been vetted through the mandated OEIS review process. Because each project must be reviewed by OEIS, a utility cannot attempt to add a new project after the OEIS Phase 1 decision by claiming that it is "offset" by a removed project.

However, after OEIS approval and up to a certain point in the CPUC's Phase 2 review process, a utility should be allowed to *remove* any projects and all associated costs from its plan. If a utility no longer wishes to pursue a project, there is no reason to require continued inclusion of the project in the plan and the attendant use of CPUC and party resources to review a dropped project. Of course, the cost of the plan should be reduced by the cost of any dropped projects. However, at some "point of no return", when the CPUC needs to draft its final Phase 2 decision and identify the approved projects, the CPUC should make clear that no more projects can be dropped. The costs of those removed projects should be removed through the review process discussed in Section 4 above.

A utility that wishes to add projects to its approved SB 884 plan after the OEIS decision can seek funding for such additional projects through its GRC process. However, the utility

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[20] See, e.g., TURN's Opening Brief in A.23-06-008, found here, p. 66.

[21] This section responds to some, but not all, of questions 1, 3 and 4 in Section F of SPD's questions.

[22] PU Code Section 8388.5(c)(2), (3), (4) and (6).

[23] *Id.*, Section 8388.5(d)(2).

[24] *Id.*, Section 8388.5(e)(1).

should be aware that if it seeking cost recovery for undergrounding activities via both the SB 884 and GRC processes, it will be subject to a rigorous requirement that only the cost of incremental activities will be funded via whichever cost recovery vehicle turns out to be secondary to the primary vehicle (see Section 4.3 above regarding incrementality).

The statutory requirement that SB 884 plans that are reviewed by the CPUC must be the same group of projects approved by OEIS is a wise and necessary one. It comports with the need for the Commission to have a defined set of projects to review under the just and reasonable requirements. For the ratemaking process to be manageable, the list of projects cannot be a moving target that is augmented during or after the CPUC's Phase 2 process. The CPUC should discourage OEIS from adopting rules that are contrary to the statutory scheme. In any event, the CPUC is responsible for the approval of plan costs and is obligated to follow the statute and not allow utilities to add projects that were not included in OEIS's approved plan.

If, in implementation of its approved plan, the utility finds that it needs to add a small amount of contiguous miles to a project (no more than 5-10% of total miles for a project), such minor changes could be allowed, in order to accommodate the minor increase in mileage, provided that such minor modifications do not increase the cost cap. But this accommodation should be kept limited (to no more than 5-10% of miles for a project, as described above) in order to prevent a utility from moving ahead with projects that are materially different from what has been vetted and approved by OEIS and the CPUC.

**6. Section I – Delayed Implementation of Approved Projects**

If a project is completed in the year after it was scheduled to be completed in the Phase 2 application (say, in Year 2 instead of Year 1), the general approach should be that the cost cap for Year 1 should be reduced by the forecast cost for the project and the forecast for year 2 increased by the cost of the project.

However, the CPUC should be aware of the possibility that a utility could game the timing of project completion in order to manipulate the results of the calculations for the CBR and unit cost Phase 2 conditions. This would serve the utility's financial interests but undermine the ratepayer protective purposes of the Phase 2 conditions that SPD-15 touts at length.[25]

To discourage such gaming, the Commission should, first, not allow any escalation of the cost of the approved project costs because of the delay. And if the approved plan called for unit costs of undergrounding to decline from year to year, the delayed project costs that are added to the price cap in year 2 should be determined by the lower approved unit cost for year 2. In addition, the Commission should require the utility to explain why the delay was outside the

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[25] SPD-15, pp. 9-12.

company's control and reserve the right to remove the costs of delayed projects from the cost cap entirely if the Commission finds that gaming is occurring.

### 7. Section J – Rejected or Abandoned Projects[26]

As discussed in Sections 4.2 and 4.4 above, only costs associated with a completed project should be recorded to the balancing account, and the costs of any project approved in the Phase 2 decision that is not completed should be removed. Those costs should be subtracted from the price cap for the applicable year as soon as the utility decides not to complete the project.

TURN agrees with Cal Advocates that both the longstanding "used and useful" requirement[27] and SB 884 do not allow recovery for costs of work that is not associated with a completed project, as there would be no undergrounded facilities providing the benefits that are supposed to be obtained from approved projects. Utilities should not be allowed to evade these requirements by including costs related to uncompleted projects, including costs recorded as AFUDC, in any GRC account.

In addition, if a project is rejected in the Phase 1 or Phase 2 review processes, costs incurred for denied projects should not be recovered from ratepayers for the same reason.[28] The Commission should recognize that the utility's approved cost of capital includes compensation for such known risks. Ratepayers should not be required to pay additional compensation for those risks. In addition, the Commission should not reduce the utility's incentive to select undergrounding only where such a project is likely to succeed.[29] Moreover, it should be remembered that the SB 884 process is voluntary and that the GRC process is an alternative means of seeking funding for undergrounding projects.

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[26] This response addresses SPD questions 1-3 in Section J. As noted below, questions 4-7 are mooted by TURN's response to these prior questions.

[27] *See, e.g.,* D.18-12-021, p. 154; D.84-09-055, 16 CPUC 2d 205, 228.

[28] D.84-09-055 contains a good discussion of the policy reasons for not approving recovery of planning, permitting, and other preliminary costs for projects that are not completed. The exception to the rule that costs of projects that are not used and useful are not recoverable – for projects that are prudently pursued "during a period of great uncertainty" (16 CPUC 2d at 229)– does not apply here. At this point in California's journey with respect to utility-caused wildfires, there is no significant uncertainty about the importance of prudent and cost-effective wildfire mitigation strategies. Nor is there any uncertainty that, in appropriate locations, undergrounding can be the superior wildfire mitigation choice. Managerial acumen is needed to propose undergrounding where it is the best use of limited ratepayer funds and not to attempt an excessive deployment of undergrounding to further shareholders' interests.

[29] D.84-09-055, 16 CPUC 2d at 229.

The challenges and complications posed by SPD questions 4 through 7 are mooted by following the clear rule that costs of projects that are not completed are not recoverable.

**8. Section E – Present Value Calculations**[30]

TURN appreciates that SPD is attentive to the requirements of recently enacted AB 2847. The Commission should make clear in a decision or ruling in advance of the submission of Phase 2 applications that those applications must include both nominal and present value (PV) lifetime calculations for the capital costs of their proposed plans. To account for the fact that different projects will start at different times over the duration of the proposed plan, the utility should include workpapers showing the lifetime costs for each proposed project.

Consistent with D.24-05-064,[31] the utility's Phase 2 application should provide CBRs and PV of lifetime revenue requirement values using the three discount rate scenarios identified in that decision.

**9. Section B – Third Party Funding**

Unfortunately, TURN does not expect utilities to obtain third party funding for a meaningful portion of undergrounding costs. However, if any such funding is obtained, it must be deducted from plan costs that are included in the balancing account. Utilities should not be allowed to include in rates or rate base any costs that were covered by third party funding. In GRCs, a utility would be able to seek recovery of any reasonable maintenance costs for third party funded underground plant to the extent that such maintenance costs are not covered by the third party funding source.

**10. Conclusion**

TURN appreciates the opportunity to respond to SPD's questions – and to see other parties' responses – in an open and transparent process. Please contact the undersigned with any questions about TURN's responses.

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[30] TURN believes "present value" not "net present value" is the correct term in this context (costs and benefits are not netted against each other in CBRs and revenue requirement calculations) so TURN uses the former term. This section addresses questions 1-3 in Section E. Question 4 is addressed to some extent in Sections 2.1 and 2.2 above, which point out that utilities have, to date, used different methodologies for calculating RSEs, which make these cost-effectiveness measures not comparable among utilities.

[31] D.24-05-064, pp. 102-105.

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