California Public
Utilities Commission

# Opening Comments on Draft Resolution SPD-15

December 28th, 2023

Via Email
SB884@cpuc.ca.gov

December 28, 2023

Rachel Peterson, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

**Re: Opening Comments on Draft Resolution SPD-15**

Dear Executive Director Peterson:

The California Farm Bureau (Farm Bureau) submits these comments on Draft Resolution SPD-15 (Draft SPD-15 or Draft Resolution) in accordance with Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and pursuant to the November 9, 2023, cover letter accompanying Draft SPD-15.

## I. Introduction

The California Farm Bureau (Farm Bureau) appreciates the effort that went into the development of the Staff Proposal for the Senate Bill (SB) 884 program (Program) and ultimately the Draft Resolution SPD-15. 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. Unfortunately, despite non-utility parties providing comments supporting the initial direction of the Staff Proposal and seeking additional clarification or updates, the Draft Resolution has removed necessary ratepayer protections and further skewed the benefits of the program to the utilities. As Farm Bureau has stated numerous times and will continue to do so, this program is entirely *voluntary*. Ratepayer protection should be at the forefront and if a utility deems the Program too onerous then they can proceed with proposing and requesting funding for undergrounding during the normal GRC process. The current Draft Resolution removes much of the balance that should be sought and has the potential to severely harm ratepayers. Farm Bureau is hopeful through this comment period and on further reflection a better balance will be struck. This Program is far too costly and potentially catastrophic to not ensure the utmost transparency and balance between utilities and ratepayers.

## II. A Decision on the Draft Resolution Should be Delayed or Postponed until OEIS has Completed their Process

While Farm Bureau understands the desire to keep the process moving, there is no reason to hasten a decision on this portion of the process when it is only a fraction of the overall program. Significant questions remain regarding the scope of the process that will come out of the Office of Energy Infrastructure Safety (OEIS) that may require this portion of the Program to fill in the gaps. Farm Bureau urges the Commission to either delay a decision on this portion of the Program or ensure that once the OEIS process is complete there will be an additional comment period that will allow for meaningful stakeholder input and engagement. As stated below, there should be no program that will begin before 2027, which guarantees there is meaningful time to get this Program correct before the initial proposals are received and the process begins.

## III. Application Requirement 2) c) Should be Removed

It was made very clear in the Commission's decision regarding Pacific Gas and Electric Company's (PG&E) recent General Rate Case (GRC) Phase 1 proceeding that the decision was to act as a bridge to the SB 884 Program. Given this language and the required timing to establish the program and review an application, at a minimum no program should begin until 2027. Given this information, there should be no reason to reconsider undergrounding targets that have already been decided in a GRC. It would be unfair to allow the utilities a second bite at the apple as well as counter to the stated notions of providing expeditious review of an application. The Commission has already made a decision based on a much larger swath of information and parties should not be expected to relitigate an issue that has already taken significant time and resources. No other utility should encounter such an issue given the current GRC schedules and institution of this program, therefore Application Requirement 2) c) should be removed.

## IV. SPD-15 Should be Corrected to Reinstate the Conditionality of Approval Rather than Automatically Approving Utility Costs

Despite statutory guidance that the Commission may authorize rate recovery *after* it has determined that the recorded costs are just and reasonable, the Draft Resolution seemingly allows the utilities to make that determination on their own and automatically include in rates any amount *they believe* should be approved. This oversight is counter to the requirements of SB 884 and removes any meaningful input from stakeholders and at a minimum careful Commission review of the correctness and accuracy of the facts and data provided by the utilities. The statute is clear the Commission must be the final arbiter of costs and cannot allow the utilities to police themselves with a one-way balancing account. The Draft Resolution must be revised to ensure there is a necessary process that provides a sufficient record for review by the Commission before approval of any previously conditionally approved costs.

## V. SPD-15 Must Remove the Utility Blank Check and Institute Cost Caps

In another disappointing move, the language regarding a cost cap over the conditionally approved amount has been removed. As the Commission and parties to this proceeding are aware, quite frequently utilities file additional applications seeking funding far above what was initially requested and ultimately approved. However, the purpose of the expedited SB 884 Program is to provide some form of certainty and *decrease* costs for ratepayers throughout the lifecycle of the Program. Providing utilities with endless opportunities and an effective blank check for seeking recovery of costs above what has been conditionally approved sends the exact wrong message and frustrates the purpose of the program.

Frequently with any kind of large scale project a certain contingency amount is established to account for things that may go wrong throughout the lifecycle of that project. It is Farm Bureau's understanding that those contingencies are already baked into the costs utilities are providing the Commission and potentially conditionally approving. By allowing a utility to blow past what has already been conditionally approved and those preset contingencies to seek endless additional above the cap cost recovery is wrong. Ratepayer advocates have found it is very difficult for the Commission to deny what has already been spent and some measure of restraint must be placed on utility spending. Ratepayers are forced to live within a budget that has been continually eroded by increasing utility bills and the utilities must learn to do so as well.

In exchange for the expedited nature of this Program, ratepayers should be provided some level of certainty in the costs of the program.

## VI. Section 3 Should be Revised to Make Clear Impacts Will be Provided for All Ratepayers and Address the Cumulative Impacts of All Other Proceedings

Section 3 of the Application Requirements discusses ratepayer impacts but does not clarify that it is all ratepayers. Given the current propensity to provide and highlight only residential ratepayers impacts in utility Applications, Farm Bureau would appreciate an amendment to include the word *all* so there is no question that the impacts for *all* ratepayers, which will certainly exist, will be transparent.

Further, there should be a requirement for the ratepayer impacts to be updated to reflect the impacts of all other proceedings. Far too often a single proceedings rate impacts is lost in the larger context of additional proceedings. For example, much was made of the reduction in the PG&E GRC Phase 1 Decision from the 26% requested revenue requirement increase by PG&E to the 11% increase the Commission approved. However, in a filed but not yet approved Annual True Up by PG&E for rates effective January 1, 2024, the preliminary forecast results in a 24.9 percent increase in PG&E's system average bundled electric rate for agricultural customers and a 34.3 percent increase in PG&E's system average rate for Direct Access (DA) and Community Choice Aggregation

(CCA) agricultural customers.[1] While the Decision in the GRC certainly helped to reduce this impact, the overall rate increase is still significant based on other proceedings. In addition, shortly after PG&E filed an interim wildfire relief proceeding (their third this year) that would add an additional $1.6 billion increase or a 7.1 percent average increase for bundled agricultural customers or 12 percent for DA and CCA agricultural customers effective March 1, 2024.[2]

While there may be a slightly greater understanding of the rate impacts at the beginning of the application, much will change by the time the first underground miles take place and certainly five to six years into the program. The Commission must have all information available and be nimble enough to identify where conditionally approved spending may have seemed prudent in 2027 but is no longer feasible in 2032.

## VII. Section 4 Should be Revised to Hold Utilities Accountable for Proposed Cost Savings

Section 4 regarding proposed "savings" must be revised to develop a more thorough evaluation of those "savings" and be clear at a minimum they must be continually included and updated in progress reports and the annual review as a means to evaluate the program and provide necessary penalties if savings are not realized. Should the proposed "savings" from undergrounding be touted as a *future* savings outside of the 10-year plan window, the Commission must ensure that it will hold the utilities accountable should those savings not be realized. A mechanism must be established to show how those savings are being realized and how they will be reflected in rates. Savings are not savings if they are simply spent by the utilities elsewhere. Further, vegetation management costs for previously completed miles should continue to be monitored and highlighted to ensure there are no remaining costs where there has been promised to be none.

## VIII. The Consequences for Failure to Satisfy Conditions of Approval Section of the Staff Proposal Should be Reinstituted

Unfortunately, the Section titled *Consequences for Failure to Satisfy Conditions of Approval* from the Staff Proposal has been removed. This Section certainly could have used additional strengthening, but the complete removal coupled with the additional changes mentioned above sends a frightening message to ratepayers. The Commission must hold utilities accountable and must provide some protection for ratepayers. This Program must provide a balance between the sureties being provided to utilities based on *their* promises and sureties to ratepayers that should the utilities break those promises, it will be the utilities not the ratepayers facing the consequences. As it stands, the current Draft Resolution does not provide those sureties to ratepayers and all but guarantees there will be significant cost overrun and little to no consequences for utilities when that

[1] Advice Letter 7066-E filed November 15, 2023, Attachment 1.
[2] A.23-12-001, filed December 1, 2023.

occurs. This Program is too large and too expensive for the Commission to expect less from the utilities.

## IX. A Process Must be Established for the Commission to Terminate the Program

The Draft Resolution remains unclear that once the proverbial train has left the station if there is any way to stop it prior to the 10 years being complete. Should new information, technologies, cost prohibitions, or other factors arise there must be the ability for the Commission to terminate the program and revert a utility back to the GRC process while also preventing another application within a certain timeframe. This is particularly important if the consequences for utility failure are not reinstituted.

## X. Conclusion

Farm Bureau appreciates the opportunity to comment on the Draft Resolution and is hopeful a decision will be delayed until the entire picture of what OEIS evaluation process will be has been determined. At a minimum, Farm Bureau hopes there will be an opportunity for comments on the final package of the two agency proposals. There are simple fixes that can be made to the Draft Resolution that reinstitute some measure of ratepayer protection while maintaining the expedited nature of the program. It is important to remember that **no utility is required to participate in this expedited program** and the tradeoff for expedited review should be extreme transparency of the costs and implications of these plans with sufficient consequences to protect ratepayers.

Sincerely,

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- SB-884 Notification List
- Service Lists for A.21-06-021, A.23-05-010, and A.22-05-016

VIA ELECTRONIC DELIVERY TO: SB884@cpuc.ca.gov

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Mr. Tomassian:

In response to an e-mail notice you sent on November 9, 2023, AT&T California (U-1001-C); the California Broadband and Video Association; Crown Castle Fiber, LLC (U-6190-C); and Sonic Telecom, LLC (U-7002-C) (collectively, the "Communications Providers") respectfully submit these comments on Draft Resolution SPD-15 ("Draft Resolution"), which establishes the Senate Bill ("SB") 884 program pursuant to Pub. Util. Code § 8388.5.

The Communications Providers commend the California Public Utilities Commission ("Commission") and staff for their work on the Draft Resolution, which establishes a thorough, workable, and appropriate process for considering SB 884's expedited utility distribution infrastructure undergrounding plans. In particular, the Communications Providers are encouraged that the Draft Resolution reflects the Communications Providers' request to revise the September 12, 2023 "Staff Proposal for SB 884 Program" ("Staff Proposal") to clarify that the investor-owned utilities ("IOUs") are not required to underground secondary electric lines and service drop cables.[1] The Communications Providers also appreciate the helpful addition in the Draft Resolution of a requirement that the IOUs include in their undergrounding plan applications "a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California."[2]

Broadband expansion requires attaching communications equipment to vertical assets such as utility poles. The Communications Providers rely on utility poles that are solely or jointly owned by the large IOUs to deliver their services.[3] If an IOU removes its poles as part of an

[1] *See* Draft Resolution, Att. 1 at 8, Application Requirement 8 ("If projects will include secondary lines and service drops, those costs and benefits must be included."); Communications Providers' Sept. 27, 2023 letter to Chirag J. Patel at 2-3 (requesting that the Commission revise the Staff Proposal to clarify that an undergrounding plan need not include secondary lines and electric service drop cables).

[2] Draft Resolution. Att. 1 at 9-10, Application Requirement 17.

[3] *See* Application 21-06-021, PG&E General Rate Case ("GRC"), Comcast GRC Opening Brief at 3, 22-23 (Nov. 4, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K338/498338970.PDF.

undergrounding project, some communications providers may face the prospect of having to either underground their overhead facilities at the same time as the IOU or discontinue service in that area.[4] Moreover, certain communications equipment, such as Wi-Fi devices, cellular radios, and antennas that provide hotspots and wireless broadband, cannot operate below ground. In this regard, the Communications Providers request modest revisions to the Draft Resolution as set out below that will better align it with SB 884. Specifically, the Communications Providers respectfully request that the Commission revise the Draft Resolution to (1) consider third-party undergrounding costs and (2) expand the undergrounding plan application requirements. The Commission also should modify the Draft Resolution to make clear that an application that does not comply with these requirements will result in either an order to modify and refile the application, or denial of the application.

**The Draft Resolution Should be Revised to Consider Third-Party Undergrounding Costs**

The Communications Providers are concerned that the Draft Resolution fails to expressly consider undergrounding costs that would be incurred by parties other than the IOUs, including communications providers, in its cost-benefit analysis provisions.[5] When communications providers share space on utility poles with an IOU, and the IOU undergrounds its facilities, it can impose substantial costs on communications providers, particularly for undergrounding projects in which utility poles would be removed.[6] These costs are likely to be then passed on to residential households and businesses in the form of increased rates or fees for communications service. In addition, undergrounding may require households and businesses to bear costs associated with trenching through their property and/or pay for conversion of their electric service from overhead to underground. The Draft Resolution's failure to consider these costs is inconsistent with SB 884, which requires that the costs of an undergrounding plan be fully considered. For instance, SB 884 requires the IOUs' undergrounding plans to include "[a]n evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions."[7]

**The Draft Resolution's Undergrounding Plan Application Requirements Should be Expanded**

Although the Draft Resolution requires that IOUs include GIS data and other information for proposed undergrounding projects in their undergrounding plan applications,[8] the details of the application requirements could be improved by including additional data. First, each application should be required to define individual undergrounding projects with sufficient granularity to

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[4] *See id.; see also* AT&T GRC Opening Brief at 2-3 (Nov. 4, 2022) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K526/498526065.PDF.

[5] Draft Resolution, Att. 1 at 8, Application Requirements 8-10.

[6] *See* Communications Providers Comments on Staff Proposal at 3 (Sept. 27, 2023) ("The Communications Providers' costs could exceed $1 million per mile of undergrounding.").

[7] Pub. Util. Code § 8388.5(c)(6) (emphasis added).

[8] Draft Resolution, Att. 1 at 9, Application Requirement 12.

allow the Commission to identify the specific location(s) and quantity(ies) of undergrounding that is/are cost-effective. Greater granularity will allow more precision in the Commission's effort to target the most cost-effective undergrounding locations and amounts.

Second, for each proposed undergrounding project, the IOU should be required to provide:

- Details on which electric conductors (e.g., primary vs. secondary lines) and equipment (e.g., meters, transformers) are proposed to be undergrounded or remain on the pole;
- A KMZ/shapefile detailing each proposed undergrounding "project" that includes the following information:
    - Actual undergrounding footages;
    - Number of poles impacted;
    - Pole tag information;
    - Third-party attachment information, if any;
    - Pole ownership information;
    - Trench details (e.g., trench depth, size of conduit);
    - Total miles undergrounded with lat/long coordinates;
    - Estimated project completion time by year; and
    - If the project will take multiple years, which segments are projected to be completed each year; and
- Provisions that address the needs of wireless carriers with radio and antenna facilities that must remain on utility-owned vertical infrastructure (poles) and retain effective access to utility-provided power to maintain wireless coverage.

**The Commission Should Modify the Draft Resolution to Make Clear That an Application That Does Not Comply with its Requirements Will Result in Either an Order to Modify and Refile the Application, or Denial of the Application**

As the Draft Resolution recognizes, implementation of SB 884 involves not only the Commission, but also the Office of Energy Infrastructure Safety ("Energy Safety").[9] Energy Safety's role is to review and approve the large IOUs' 10-year distribution infrastructure undergrounding plans before the Commission undertakes a similar process.[10] Energy Safety has determined that it should develop and issue mandatory 10-year distribution infrastructure undergrounding guidelines for the large IOUs as part of its SB 884 responsibilities. Although the Communications Providers have repeatedly asked Energy Safety during its working group meetings to include communications infrastructure issues in its undergrounding guidelines, Energy Safety has not yet agreed to do so. Therefore, it is critical that the Commission make clear in Resolution SPD-15 that the IOUs' applications will be denied, or required to be amended and refiled, unless they fully address all the required elements set out in the Draft Resolution, as well as the additional elements discussed above, including third-party undergrounding costs. Thus, the Commission should modify draft Resolution SPD-15 to (1) require the large IOUs' applications to include non-electric pole

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[9] *See* Draft Resolution at 2-4; Pub. Util. Code §§ 8388.5(c) and (d).

[10] Pub. Util. Code § 8388.5(d).

attachment and third-party costs associated with undergrounding distribution infrastructure, and (2) put the large IOUs on notice that failure to comply with the first requirement will result in either an order to modify and refile the application, or denial of the application.

Respectfully submitted,

*/ s / Jerome F. Candelaria*
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For the Communications Providers[11]

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SB-884 Notification List
Service Lists for A.21-06-021, A.23-05-010, and A.22-05-016
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[11] In accordance with Rule 1.18(d) of the Commission's Rules, the signatory has been authorized to submit this letter on behalf of all the Communications Providers.

Pacific Gas and Electric Company™

**Jamie Martin**
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December 28, 2023

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Re: **Pacific Gas and Electric Company's Comments on Draft Resolution SPD-15**

Dear Executive Director Peterson:

Pacific Gas and Electric Company (PG&E) provides the following comments on the Draft Resolution adopting Safety Policy Division's (SPD) Staff Proposal for the Senate Bill 884 (SB 884) expedited underground program. The Staff Proposal details the process and requirements for the California Public Utilities Commission (Commission) to review an electrical corporation's 10-year distribution infrastructure undergrounding plan (Plan) and its application for review and conditional approval of the Plan's costs.

PG&E appreciates the detail and clarity that has been added to the Staff Proposal. However, some limited modifications to the Staff Proposal are needed in order to accurately and expeditiously record, review, and approve SB 884 Program plan costs. PG&E's comments on the Draft Resolution are focused on the following areas:

1. Providing additional clarity regarding cost accounting and recovery processes;
2. Modifying the avoided cost requirements;
3. Clarifications regarding the threshold Cost-Benefit Ratio (CBR); and
4. Additional issues including discovery process, removing unnecessary requirements, engagement in change management process, the scope of facilities available for reporting in the Plan, and inclusion of incremental undergrounding miles where justified.

In Appendix A, PG&E provides proposed language for modifications to the Draft Resolution and Staff Proposal to address the issues raised in these comments. PG&E appreciates the Commission's and Staff's consideration of these comments and recommendations as it finalizes the Resolution.

## I. CLARIFYING COST ACCOUNTING AND RECOVERY PROCESSES

The Draft Resolution and Staff Proposal describe a two-step cost recovery process for SB 884 Program costs that includes: (1) a one-way balancing account for recording and recovering approved annual costs; and (2) a memorandum account for recording costs exceeding the approved annual cost cap. Costs in the memorandum account may only be recovered by an electrical corporation after Commission review to determine whether the costs were prudently incurred, incremental to other funding, and are just and reasonable.[1]

PG&E supports the two-step cost recovery mechanism described in the Draft Resolution and Staff Proposal. However, PG&E has identified three areas related to cost recovery that it recommends be clarified or addressed in the final Resolution and Staff Proposal: (1) the calculation and application of the unit cost cap; (2) expedited approval for costs recorded in the memorandum account; and (3) cost recovery for "abandoned" projects. PG&E discusses each of these items below.

### A. Average Recorded Unit Cost Cap

The Draft Resolution establishes an annual unit cost cap for Plan costs booked to the one-way balancing account to help ensure that rates associated with undergrounding are just and reasonable.[2] The Staff Proposal defines unit cost as the total costs to install one mile of undergrounding.[3] Unit cost elements include program management, project execution, design,

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[1] Draft Resolution, pp. 4-5 and Staff Proposal, pp. 10-11.

[2] Draft Resolution, pp. 8-9 and Staff Proposal, p. 10.

[3] Draft Resolution, Staff Proposal, p. 10.

estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, permitting, close-out costs, and staff overhead.

There are four aspects of the unit cost cap included in the Draft Resolution and Staff Proposal that PG&E recommends be modified: (1) the number of years considered for the unit cost cap evaluation; (2) reconciling discrepancies between the Draft Resolution and the Staff Proposal regarding the use of "average recorded" costs for the unit cost cap; (3) inclusion of only completed projects in the average unit cost cap calculation; and (4) use of the memorandum account for costs exceeding the cost cap.

First, the Staff Proposal adopts an annual unit cost cap that is calculated for a given year.[4] However, complex construction projects, such as undergrounding, do not always fit into neat annual buckets that can be used to compare actual unit costs to the unit cost cap. Moreover, small timing issues can have a considerable impact on unit cost evaluation. For example, if a project with a high unit cost is completed on December 31st and a project with a low unit cost is completed one day later, on January 1st, under the current Staff Proposal only the high unit cost project would be considered and the high and low unit costs projects, completed one day apart, would not be averaged. To address this problem, PG&E proposes that the cost cap be calculated on a three-year rolling basis. Thus, for a given year, the adopted cost cap would be compared to the average of unit costs for the given year as well as the two prior years. This will prevent unreasonable outcomes which can occur if the unit cost evaluation is narrowly focused on a single year.

Second, PG&E identified a discrepancy in how the unit cost cap is described in the Draft Resolution and in the Staff Proposal and recommends that the language in the Draft Resolution be modified to match the language in the Staff Proposal. Specifically, in discussing the unit cost cap, the Draft Resolution explains that "a large electrical corporation will not recover costs booked to the one-way balancing account in any given year if the unit costs for such projects

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[4] Draft Resolution, Staff Proposal, p. 10.

exceed a known value."[5] On the other hand, the Staff Proposal explains "[t]he average recorded unit cost in any given year must not exceed the approved unit cost target for that year."[6] The key difference between the language in the two documents is the use of the term "average." The Staff Proposal describes *average recorded unit costs* for a project year whereas the Draft Resolution refers to *unit costs for such projects*. The language in the Staff Proposal is accurate in how it describes the conditions for approval of Plan costs. The Draft Resolution language suggests that the unit cost for each project must be below a cap. An electric corporation should be held to an average annual unit cost which affords an opportunity to balance more difficult, higher cost projects with lower cost projects. An electric corporation should not be held to a single unit cost cap for each project as implied by the language in the Draft Resolution.

Third, it is unclear if only completed project costs are considered as a part of the unit cost cap evaluation or if the cap evaluation considers costs recorded in a specific year regardless of whether the project is completed in that year. For example, the Draft Resolution refers to the annual unit cost cap evaluating costs "booked to the one-way balancing account" but later on the same page states that the Staff Proposal ensures that "work being funded through the one-way balancing account is being <u>completed</u> at the cost per mile committed to in the approved Plan."[7] The Staff Proposal refers to "average recorded unit cost in any given year must not exceed the approved unit cost target for that year"[8] but does not specify whether the costs considered are only for completed projects. PG&E believes that the most reasonable approach would be for project costs to be included in the average unit cost calculation in the year the project is completed. An undergrounding project may take several years and costs in any specific year during the project life cycle could be substantially higher or lower than other years. The only way to determine a project's actual unit cost is once the project is completed and becomes used

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[5] Draft Resolution, p. 9.

[6] Draft Resolution, Staff Proposal, p. 10.

[7] Draft Resolution, p. 9 (emphasis added).

[8] Draft Resolution, Staff Proposal, p. 10.

and useful. Evaluating unit costs in a given year for projects completed in that year is also consistent with how the total annual costs and average CBR are evaluated.[9] PG&E notes that even after a specific project goes into service (*i.e.*, is completed), there can be months of close out costs such as site remediation, final permit conditions, and final project documentation. Thus, to evaluate unit costs for any given year in a timely manner, the electrical corporation should propose in its Plan a process for establishing a proxy for close out costs that would be included in the costs for completed projects in that year in order to calculate the annual average unit cost and assess whether those completed projects are, on average, within the annual unit cost cap. The actual close out costs for a project would be trued up and recovery would be managed through the appropriate account when these costs are final but, given the potential delay in close out costs, a proxy for close out costs would need to be used for the cost cap evaluation.

Finally, the Staff Proposal indicates that for costs booked into the one-way balancing account, "[t]he average recorded unit cost in any given year must not exceed the approved unit cost target for that year."[10] Project completion does not always follow a calendar year schedule and in any given year the project costs for that year may be substantially higher or lower. For example, as explained above, a very high unit cost project may have been completed on December 31 and then two very low unit cost projects completed on January 1. Taken together, these three projects may have been well below the unit cost cap. One way to address this problem is by adopting the three-year rolling average approach proposed by PG&E above.

If the Commission decides not to adopt PG&E's three-year proposal, at a minimum an electrical corporation should not be precluded from recovering costs simply because of the difference of a few days. In cases where unit costs exceed the annual cost cap, an electrical corporation should be able to choose one of two options: (1) book costs into the one-way balancing account up to the established average annual unit cost cap and record any additional

[9] Draft Resolution, Staff Proposal, p. 4, n. 4 (total annual costs based on project being completed (*i.e.*, "used and useful") and p. 10 (CBR evaluated for completed projects).

[10] Draft Resolution, Staff Proposal, p. 10.

costs for projects completed in that year to the memorandum account for further review by the Commission; or (2) book costs for specific projects into the one-way balancing account up to the unit cost cap and then record remaining projects that would result in exceeding the unit cost cap into the memorandum account for further review. This approach is consistent with the Draft Resolution by allowing "large electrical corporations to recover the costs of undergrounding without undue delays once infrastructure is used and useful"[11] while also protecting customers by ensuring that costs above the average unit cost cap are reviewed by the Commission through the memorandum account. This is also consistent with the treatment of total annual costs which allows the costs up to the cap to be booked into the one-way balancing account and costs above the cap to be booked into the memorandum account[12] and Commission precedent which allows a party the opportunity to seek recovery of costs above a previously approved unit cost.[13]

### B. Expedited Review for Memorandum Account Costs

PG&E recommends that the final Resolution adopt an expedited nine (9)-month process for filing, reviewing, and approving an application for recovering costs recorded to the memorandum account. PG&E recognizes the importance of demonstrating in a cost recovery application that the costs recorded to the memorandum account are just and reasonable. However, memorandum account proceedings can often last for several years or more, resulting in lengthy delays in cost recovery. Expedited review of the memorandum account is consistent with the Commission's determination that there should not be "undue delays [in cost recovery] once infrastructure is used and useful."[14] Nine months will allow sufficient time for parties to review PG&E's application, propound discovery, submit testimony if needed, and for the

[11] Draft Resolution, p. 7.

[12] Draft Resolution, Staff Proposal, p. 11.

[13] *See e.g. Pacific Gas and Electric Company*, Decision (D.) 21-11-036 (2021), 2021 Cal. PUC LEXIS 555 at *9 ("If PG&E incurs unit costs that are significantly higher than what the Commission has found reasonable, it has the burden to demonstrate that the additional costs are reasonable before they can be added to rates.").

[14] Draft Resolution, p. 7.

Commission to consider PG&E's request. Given the limited scope of these proceedings (*i.e.*, undergrounding projects only that were completed in a specific year and pursuant to a previously approved Plan), it is reasonable to expedite the process and avoid unnecessary and lengthy procedural delays.

PG&E's proposal for an expedited review process is also consistent with the Staff Proposal requirement that "[n]o more than one Phase 3 Application may be filed each year."[15] If electrical corporations are only able to file one application a year, but resolution of an application takes 2-3 years, this could result in multiple memorandum account applications pending in any given year. It would create significant burdens for the Commission, Staff, parties, and PG&E to have multiple applications pending in a given year at various stages in the proceedings. Instead, by resolving an application within 9 months, the Commission can establish an orderly and expedited process and prevent multiple applications pending at the same time.

**C. Cost Recovery for Abandoned Projects**

The Draft Resolution allows an electric corporation to recover costs for undergrounding projects via the one-way balancing account once infrastructure is used and useful.[16] While unlikely, it is possible that an electric corporation could begin work on an undergrounding project that ultimately is not completed and determined not to be in our customers' best interests to complete, due to risk model changes, workplan updates, infeasible permit condition requirements or other unforeseen circumstances. The Commission allows utilities to recover abandoned plant costs under certain conditions.[17] The Draft Resolution should be modified to allow an electric corporation to record abandoned project costs in the memorandum account, subject to reasonableness review, for work that is started on a project that is selected, but is ultimately not completed, and will not meet the "used and useful" cost recovery standard.

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[15] Draft Resolution, Staff Proposal, p. 11.

[16] Draft Resolution, p. 7.

[17] *See e.g. Golden State Water*, D.11-09-017 (2011), 2011 Cal. PUC LEXIS 425, Finding of Fact 3; *Pacific Gas and Electric Company*, D.11-05-018 (2011), 2011 Cal. PUC LEXIS 275 *66 (describing Commission precedent and requirements for recovering abandoned plant costs).

## II. MODIFICATIONS TO AVOIDED COST REQUIREMENTS

The Draft Resolution requires an electric corporation to forecast costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan. Specifically, the electric corporation must identify reduced, deferred, or avoided costs for each year of the 10-year Plan and those that are expected to continue beyond the 10-year Plan.[18] The electric corporation must provide workpapers showing the total and average avoided costs and the calculations of those costs.[19]

PG&E supports the requirement to provide information about avoided costs in its Plan annual updates. This would consist of modeling and forecasting avoided costs based on the number of underground miles completed per year at the program level. The model will show avoided costs each year for the life of the asset. PG&E recommends that the avoided cost information be provided only in the annual report, as opposed to both the annual and mid-year reports, so that the total number of miles completed in that year can serve as the basis for the avoided cost calculations.

The Staff Proposal refers to, but does not define, "average avoided costs."[20] PG&E recommends that average avoided cost be replaced by the term "avoided cost per mile of undergrounding" to clarify the specific metric the electric corporation is required to provide.

## III. CLARIFYING AND CALCULATING THE THRESHOLD CBR

PG&E has identified a discrepancy in how the annual minimum cost-benefit ratio (CBR) threshold is described in the Draft Resolution and in the Staff Proposal and requests that the language be corrected for consistency. Specifically, the Draft Resolution states that the CBR provisions of the Staff Proposal include "[e]stablishing an annual minimum [CBR] threshold for projects completed and booked to the one-way balancing account."[21] However, elsewhere, the

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[18] Draft Resolution, p. 7.

[19] Draft Resolution, Staff Proposal, p. 12.

[20] Draft Resolution, Staff Proposal, p. 12.

[21] Draft Resolution, p. 9.

Draft Resolution clarifies that the CBR threshold "must be achieved, on average, for cost recovery of completed projects."[22] This later statement aligns with the Staff Proposal, which calls for the *average* CBR of all projects completed in a year to equal or exceed the CBR threshold for that year.[23] In order to clarify that the CBR threshold will provide a benchmark for the average CBR of projects completed in a year, rather than each individual project, PG&E requests that Item 6 in the Draft Resolution be corrected to align with the language on page 10 of the Resolution and with the Staff Proposal. PG&E has provided recommended language for the final Resolution in Appendix A.

PG&E also proposes the Commission apply the average CBR threshold over a longer time interval, instead of on an annual basis. As written, the Staff Proposal specifies that utilities' Phase 2 Applications must present a forecasted average CBR for each year of the application period.[24] Achieving a precise average CBR on an annual basis may be challenging. Due to construction-related factors, the precise timing of undergrounding projects may shift between the years of a Plan. While a group of projects may achieve its original forecasted average CBR, some projects may be completed earlier or later than anticipated. As a result, PG&E suggests that rather than on an annual basis, any average CBR thresholds required should be set for a longer time interval—for example, every three (3) years, or for the period during which a utility selects projects based on one version of its risk model. This is similar to the approach PG&E proposed above in Section II.A regarding unit costs.

Finally, SPD's final guidelines for cost recovery should align with a framework in which utilities consider factors in addition to CBR when selecting sites for undergrounding in their Plans. As PG&E articulated in its earlier comments on the Staff Proposal, CBR should not be

[22] Draft Resolution, p. 10.

[23] Staff Proposal, p. 10 (Conditions for Approval of Plan Costs item 3).

[24] Staff Proposal, p. 8.

the "sole determinant" of risk mitigation strategies.[25] Additional considerations like net benefits that incorporate reliability and public safety will be considered when selecting undergrounding projects to meet SB 884's goals of substantially increasing reliability while also substantially reducing wildfire risk.[26]

## IV. ADDITIONAL ISSUES

### A. Facilitating an Efficient Discovery Process

The Draft Resolution states that due to the SB 884 Program's expedited schedule, parties shall respond to discovery requests within five (5) business days in either Phase of the SB 884 Program.[27] PG&E recognizes the need to respond expeditiously to discovery requests given the short review schedule and therefore agrees with this discovery schedule. In order to reduce administrative burden and facilitate the exchange of information among interested parties, PG&E recommends that all parties have access to all discovery responses and be expected to review all other responses to avoid duplication of effort. In addition, PG&E suggests that parties be required to work together on reasonable requests for discovery extensions and meet and confer as needed to work through discovery issues.

### B. Removing Unnecessary Requirements

The Staff Proposal requires that a Phase 2 Application distinguish between forecast costs already approved by the Commission, forecast costs for which the Commission previously denied a request for recovery, and forecast costs that have not yet been the subject of a request for recovery.[28] PG&E supports maintaining clarity around the funding source for undergrounding projects, but recommends that this requirement be removed because it is

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[25] PG&E Pacific Gas and Electric Company's Comments on Safety Policy Division Staff's Proposal for the Senate Bill 884 Expedited Undergrounding Program. September 27, 2023, pp. 5-6.

[26] Staff Proposal, p. 2.

[27] Staff Proposal, p. 4.

[28] Staff Proposal, pp. 6-7 (Item 2).

unnecessary and may not be possible where the Commission has approved other forecasts of system hardening costs that are not based on specific projects.

As a preliminary matter, PG&E will not be submitting forecasted costs in its Phase 2 Application that have already been approved by the Commission in its GRC or other proceedings. In addition, other system hardening forecasts that include undergrounding costs may be based on miles or another metric, rather than a list of specific projects. For example, PG&E submits forecasted undergrounding costs in its GRC based on a total number of System Hardening underground miles for the 4-year GRC period and does not request funding for a list of specific projects. In contrast, PG&E's SB 884 Plan forecast would be based on a specific project selection framework, including the list of specific, anticipated projects. Because the forecast basis in PG&E's GRC and in an SB 884 Phase 2 Application would be different (*i.e.,* number of miles in the GRC versus project-specific selection framework in the Phase 2 Application), it would not be possible to identify forecasted projects costs included in a Phase 2 Application for which the Commission previously denied a request for recovery. Given this mismatch, the requirements for comparing Plan forecasts to other approved system hardening forecasts should be deleted.

### C. Stakeholder Engagement in Developing the SB 884 Plan Change Management Process

The Staff Proposal notes that the procedures for considering changes to elements of an SB 884 Plan will be determined by the Commission in coordination with Energy Safety in a subsequent process.[29] PG&E looks forward to participating in the change management process as it is developed by the CPUC and Energy Safety.

### D. Availability of GIS Data for Poles Having Lease Agreements with Communications Companies

The Staff Proposal requires that electrical corporations provide GIS data indicating the locations of poles which have lease agreements with communications companies and that are

[29] Staff Proposal, p. 13.

jointly owned.[30] PG&E recommends that this requirement be modified to only require GIS data indicating the locations of poles which have lease agreements with communications companies and which are jointly owned, *where available*. Not all lease agreements are digitized, and GIS data can only be provided where digitized lease agreements are available.

### E. Inclusion of Incremental Undergrounding Plan Miles Where Justified

The Draft Resolution indicates that "[o]nly projects located in Tier 2 or Tier 3 high-fire threat districts (HFTD) areas . . . or rebuild areas are eligible."[31] As stakeholders have discussed in comments and workshops with Energy Safety, a reasonable implementation of SB 884 would allow incremental miles outside of an HFTD to be included in a Plan if doing so is explained and justified in the Plan. For example, a Plan may include undergrounding a 10 mile circuit of which 9.5 miles is in a Tier 3 area and 0.5 miles is outside of the HFTD boundary. It would make little sense, in that case, to underground 9.5 miles and leave the remaining 0.5 miles above ground simply because it is outside an HFTD area. Most electrical circuits in California were designed and built well before HFTD areas were adopted by the Commission and thus circuits do not strictly follow HFTD boundaries. In other cases, because of the passage of time since the HFTD area maps were approved, circuits in areas such as PG&E's High Fire Risk Areas (HFRAs) may merit undergrounding.

The Draft Resolution should be modified to include a footnote stating: "In some cases, undergrounding projects can be located outside an HFTD and rebuild areas or a portion of the projects can be located outside HFTD and fire rebuild areas, so long as the electrical corporation explains and justifies the inclusion of these projects and/or portions of projects."

[30] Staff Proposal, p. 9.

[31] Draft Resolution, p. 2.

## V. CONCLUSION

PG&E appreciates the opportunity to provide these comments and looks forward to continuing to partner with the Commission and stakeholders on this important work. If you have any questions, please do not hesitate to contact the undersigned at Jamie.Martin@pge.com.

Very truly yours,

*/s/ Jamie Martin*

Jamie Martin

Cc: Service lists for A.21-06-021, A.23-05-010, and A.22-05-016 and SB 884 Notification List

## Appendix A
## PG&E's Proposed Language for Draft Resolution[32]

| Location | Proposed Language |
|---|---|
| Draft Resolution, p. 2 | After the second to last sentence in the first paragraph ending "or rebuild areas are eligible" add the following footnote:<br>In some cases, undergrounding projects can be located outside an HFTD and rebuild areas or a portion of the projects can be located outside HFTD and fire rebuild areas, so long as the electrical corporation explains and justifies the inclusion of these projects and/or portions of projects. |
| Draft Resolution, p. 5 | Add the following language to the first full paragraph:<br>During Phase 3, the Commission will conduct an expedited nine (9) month review of any applications for recovery of costs recorded in the memorandum account (i.e., any costs that exceed the annual cost caps established in Phase 2) to determine whether those costs were just, reasonable, and incremental to any other costs approved by the Commission. |
| Draft Resolution, p. 7 | Add the following language to the third full paragraph:<br>The Staff Proposal also allows participating large electrical corporations to track costs incurred to execute the Plan in accordance with this Resolution and its Attachment 1, and the Commission's Phase 2 Decision in excess of the annual one-way balancing account or abandoned plant costs in a memorandum account. |
| Draft Resolution, p. 9 | Revise item 6 in the list at the top of the page as follows:<br>Establishing a~~n annual~~ minimum cost-benefit ratio (CBR) threshold that must be achieved, on average, for projects completed and booked to the one-way balancing account within a 3-year time period. |
| Draft Resolution, p. 9 | In the second full paragraph, modify the following sentence:<br>Item 5, described above, likewise provides assurance that a large electrical corporation will not recover costs booked to the one-way balancing account in any given year if the average recorded unit costs for projects completed in that year and the prior two years exceed the approved unit cost target. ~~such projects exceed a known value.~~ If the unit cost cap is exceeded, the electrical corporation may choose one of two options: (1) book costs into the one-way balancing account up to the established average annual unit cost cap and record any additional costs for projects completed in that year to the memorandum account for further review by the |

[32] Underlining represents proposed additions and strikethrough proposed deletions.

| Location | Proposed Language |
|---|---|
| | Commission; or (2) book costs for specific projects into the one-way balancing account up to the unit cost cap and then record remaining projects that would result in exceeding the unit cost cap into the memorandum account for further review. |
| Draft Resolution, p. 11 | It is reasonable to include annual cost caps~~,~~ and unit cost limits, and cost-effectiveness thresholds applicable for three-year periods as part of the conditions for approval in the Phase 2 Application decision. |
| Draft Resolution, Staff Proposal, pp. 6-7 | Under Application Requirements delete Item 2). |
| Draft Resolution, Staff Proposal, p. 10 | Under Conditions for Approval of Plan Costs add the following language:<br>3) The average recorded CBR for all projects completed in a given three-year period must equal or exceed the average threshold CBR value for that three-year time period. |
| Draft Resolution, Staff Proposal, p. 10 | Under Conditions for Approval of Plan Costs add the following language:<br>4) The average recorded unit cost in any given year for completed projects and the prior two years must not exceed the approved unit cost target for that year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs. If the unit cost cap is exceeded, the electrical corporation may choose one of two options: (1) book costs into the one-way balancing account up to the established average annual unit cost cap and record any additional costs for projects completed in that year to the memorandum account for further review by the Commission; or (2) book costs for specific projects into the one-way balancing account up to the unit cost cap and then record remaining projects that would result in exceeding the unit cost cap into the memorandum account for further review. |
| Draft Resolution, Staff Proposal, p. 11 | Add the following language to the last sentence in the first paragraph:<br>No more than one Phase 3 Application may be filed each year and applications shall be expedited and resolved within nine (9) months of filing. |
| Draft Resolution, Staff Proposal, p. 11 | Add the following language to the first paragraph:<br>If the large electrical corporation incurs costs in any given year that exceed the annual cost cap for the one-way balancing account established pursuant to a Phase 2 Decision or for abandoned plant, the large electrical corporation shall record excess costs in the memorandum account established pursuant to the Phase 2 Decision. |

| Location | Proposed Language |
|---|---|
| Draft Resolution, Staff Proposal, p. 12 | Modify Item 7) in Progress Reports:<br>7) GIS data showing location and status of each project (in Geodatabases or other suitable format), where available; |
| Draft Resolution, Staff Proposal, p. 12 | Modify Item 9) in Progress Reports:<br>9) Total and average avoided cost per mile of undergrounding ~~avoided costs~~ and workpapers showing calculation of avoided cost per mile of undergrounding ~~avoided costs~~. |

December 28, 2023 **VIA ELECTRONIC MAIL**

Rachel Peterson, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
SB884@cpuc.ca.gov

**Subject: Public Advocates Office's Comments on Draft Resolution SPD-15 and the Staff Proposal for the SB 884 Program**

Dear Executive Director Peterson,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following comments on Draft Resolution SPD-15 for the SB 884 Program. Please contact Nathaniel Skinner (Nathaniel.Skinner@cpuc.ca.gov), Program Manager, or Henry Burton (Henry.Burton@cpuc.ca.gov), Program and Project Supervisor, with any questions relating to these comments.

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

Sincerely yours,

/s/ Nathaniel Skinner
Program Manager

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## I. INTRODUCTION

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these comments on Draft Resolution SPD-15, which adopts the Commission's Staff Proposal for the Senate Bill (SB) 884 Program.

Senate Bill (SB) 884, codified as Public Utilities (PU) Code section 8388.5, went into effect on January 1, 2023. This statute directs the Commission to establish a program for long-term utility distribution undergrounding plans, and authorizes large electrical corporations (utilities) to participate in that program.[1], [2] On September 13, 2023, the Safety Policy Division (SPD) issued a draft proposal that establishes the process and requirements for the Commission's review of the utilities SB 884 program applications.[3] On September 27, 2023, Cal Advocates and other stakeholders filed informal comments on the September 2023 Draft Staff Proposal.[4]

On November 9, 2023, SPD served Draft Resolution SPD-15 to adopt a revised version of the Staff Proposal.[5] The revised Staff Proposal establishes three phases for a utility's SB 884 program: Phase 1 covers review of the Plan by the Office of Energy Infrastructure Safety (Energy Safety); Phase 2 provides for review of the utility's plan (in an application proceeding) by the Commission; and Phase 3 pertains to recovery of costs recorded in a balancing account and a memorandum account.[6]

The comment letter for Draft Resolution SPD-15 invites interested persons to file opening comments by December 28, 2023 and reply comments by January 11, 2024. Comments are limited to fifteen pages in length.[7]

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[1] Many of the Public Utilities Code requirements relating to wildfires apply to "electrical corporations." *See, e.g.*, Public Utilities Code section 8388.5. These comments use the more common term "utilities" to refer to the entities that must comply with the wildfire safety provisions of the Public Utilities Code.

[2] PU Code section 8385 and section 8388.5.

[3] SPD, *Staff Proposal for SB 884 Program*, September 13, 2023 (September 2023 Draft Staff Proposal).

[4] Cal Advocates, *Public Advocates Office's Informal Comments on the Staff Proposal for the SB 884 Program*, September 27, 2023 (Cal Advocates comments on September 2023 Staff Proposal).

[5] SPD, Draft Resolution SPD-15, November 9, 2023 (Draft Resolution) and Attachment 1, *Staff Proposal for SB 884 Program*, November 9, 2023 (Staff Proposal).

[6] Staff Proposal at 4.

[7] SPD, Comment letter and Certificate of Service for SPD-15, November 9, 2023.

## II. Adoption of an Incomplete Program

### A. The Commission should withdraw Draft Resolution SPD-15 until Energy Safety develops guidelines for Phase 1.

Draft Resolution SPD-15 errs in several legal and technical respects (discussed in sections III through V of these comments). Adoption of the Staff Proposal before Energy Safety issues its guidance for Phase 1 is inconsistent with the requirements of PU Code section 8388.5(a).[8]

Currently, Energy Safety has not issued guidelines for SB 884 plans that utilities will submit in Phase 1. It is unlikely that Energy Safety will issue draft guidelines until after the Commission votes on Draft Resolution SPD-15.[9] Without guidance from Energy Safety, the Commission's Staff Proposal only addresses part of the program that the Commission is required to establish.[10] If the Commission were to adopt Draft Resolution SPD-15 at this point in time, it would adopt an incomplete program and risk legal error by creating misalignment between the Commission's and Energy Safety's implementations of SB 884. The Commission can avoid such a risk by delaying adoption of the draft resolution until it has had the opportunity to review Energy Safety's guidelines.

Delaying adoption of Draft Resolution SPD-15 would have no substantive effect. The Resolution and Staff Proposal will not meaningfully take effect until utilities are able to submit plans to Energy Safety. This cannot occur until Energy Safety has finalized its guidelines. Therefore, delaying adoption of the Staff Proposal will allow both agencies to coordinate appropriately without unduly burdening utilities or delaying the implementation of undergrounding projects.

Cal Advocates recommends that the Commission withdraw Draft Resolution SPD-15 and reissue it when Energy Safety issues its guidelines for SB 884 Plans. While the draft guidelines are in development, CPUC and Energy Safety staff can jointly consider the issues already identified and any new issues identified by stakeholders and staff. Following Energy Safety's issuance of draft guidelines on the Plans, stakeholders should be given the opportunity to review and comment on both Energy Safety's and the Commission's guidelines as a whole. This will ensure alignment between the two phases of the SB 884 program and minimize future conflicts that could otherwise arise during the expedited review periods at each agency.

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[8] "*The commission shall establish* an expedited utility distribution infrastructure undergrounding program consistent with this section." PU Code section 8388.5(a) (emphasis added).

[9] Energy Safety held a series of working groups between November 7, 2023 and December 12, 2023 to solicit proposals from utilities and stakeholders on various aspects of the forthcoming guidelines. Stakeholders have a further chance to file opening and reply comments on these workshops by January 18, 2024. Draft Resolution SPD-15 is on the agenda for the voting meeting on January 25, 2024.

[10] PU Code section 8388.5(a).

## III. Cost Recovery Process

### A. The proposed cost recovery mechanisms are at odds with the Commission's statutory obligation to ensure just and reasonable rates.

The Staff Proposal states that, once a utility's SB 884 application is conditionally approved in Phase 2, the utility "will establish a one-way balancing account to recover costs from rates up to an authorized target cap."[11] Costs recorded to the balancing account would be subject to the following conditions:[12] a cap on the total amount spent in each year; a minimum average cost-benefit ratio (CBR); and a cap on the average unit cost of undergrounding. If the utility incurs costs in excess of the total annual cap, it will record such excess costs in a memorandum account and seek recovery through a series of Phase 3 applications.[13]

Draft Resolution SPD-15 asserts that this proposed cost recovery mechanism will: (1) provide "regulatory certainty" through "clear standards of review," (2) safeguard ratepayers by ensuring costs are just and reasonable, and (3) allow utilities to recover costs "without undue delays."[14] These claims are erroneous.

First, the Staff Proposal says the Commission may approve a balancing account for each of the 10 years covered by the plan if certain conditions are met.[15] However, Draft Resolution SPD-15 and the Staff Proposal do not provide for any review of the costs recorded in the balancing account to determine whether the recorded costs are just and reasonable.[16, 17] This does not comport with PU Code Section 8388.5(e)(6), which requires the commission to "authorize recovery of recorded costs that are *determined to be just and reasonable*."[18] The Staff Proposal is also inconsistent with

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[11] Staff Proposal at 4.

[12] Staff Proposal at 10.

[13] Staff Proposal at 4. The Staff Proposal is silent on how utilities will record costs in the event that costs do not exceed the annual cap, but fail to meet either the unit cost cap or the minimum CBR conditions.

[14] Draft Resolution SPD-15 at 6-10.

[15] Draft Resolution SPD-15 at 2; Staff Proposal at 10.

[16] Draft Resolution SPD-15 at 2, 4-5, and 7. Draft Resolution SPD-15 refers to authorizing the utility to use a balancing account, but makes no mention of reviewing costs after they are recorded in the account. ("The large electrical corporation will establish a one-way balancing account to recover costs from rates up to an authorized target cap"). The Draft Resolution appears to state that once costs are recorded in the balancing account, cost recovery will be approved automatically without further scrutiny. ("One-way balancing accounts allow participating large electrical corporations to recover the costs of undergrounding without undue delays once infrastructure is used and useful.")

[17] Staff Proposal at 10-12. The Staff Proposal contains a section on review of costs recorded in memorandum accounts, but contains no mention of review of costs recorded in balancing accounts.

[18] PU Code section 8388.5(e)(6) (emphasis added).

Commission precedent, where the Commission holds a proceeding to assess whether a balancing account is merited and whether recovery of costs in that account is just and reasonable.[19]

Second, the Staff Proposal provides for excess costs to be recorded in a memorandum account each year and for the Commission to determine, through an application proceeding, whether such recorded costs are just and reasonable.[20] This accounting method would allow utilities to circumvent any cost caps established as part of the conditional approval decision (Phase 2), as well as other cost requirements established by the Commission in Phase 2.[21] Approval of such an accounting method would allow utilities to spend unlimited amounts on their undergrounding programs and seek recovery afterwards. Not only does this approach fail to protect ratepayers from excessive costs, it also fails to comport with SB 884. PU Code section 8388.5(e)(1) requires the utility to request the Commission's conditional approval for a plan's forecasted costs – not an unlimited amount of spending. PU Code section 8388.5(e)(1) also requires the utility to show how cost targets are expected to decline over time.[22] This language establishes a presumption that additional costs are presumptively unreasonable (since the approved plan is reasonable) and indicates a legislative intent that costs (such as undergrounding) should be constrained and carefully managed to protect ratepayers.

### 1. The Staff Proposal's balancing account lacks sufficient Commission review to meet legal requirements.

The Staff Proposal states that the costs recorded in the balancing account must meet certain conditions established in Phase 2, including cost caps and a minimum average CBR.[23] However, the Staff Proposal does not specify how or whether the Commission will review the balancing account.[24] Specifically, the Staff Proposal does not set forth what a utility must do to demonstrate that the costs

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[19] D.12-12-029*,* Conclusion of Law 1: "Remaining applicants have not met their burden of demonstrating that they had addressed all factual and legal issues necessary to justify the proposed balancing account, and that the proposed rates would be just and reasonable."

*See also*, D.19-03-025: "Finally, this decision grants Applicants the authority to modify the Safety Enhancement Expense Balancing Accounts and the Safety Enhancement Capital Cost Balancing Accounts authorized by the Commission in D.14-06-007; and create new one-way balancing accounts to record costs for Phase 2 projects."

[20] Staff Proposal at 11.

[21] PU Code sections 8388.5(e)(1)(A), 8388.5(e)(1)(B), and 8388.5(e)(1)(C).

[22] PU Code sections 8388.5(e)(1) and 8388.5(e)(1)(C).

[23] Staff Proposal at 10.

[24] Draft Resolution SPD-15 at 2 states, "the Commission may approve cost recovery in a one-way balancing account for each of the 10 years covered by the plan. The conditions for recovering costs via the one-way balancing account will include those contained in the attached Staff Proposal." The Staff Proposal contains a section on review of costs recorded in memorandum accounts (at 10-12), but contains no mention of review of costs recorded in balancing accounts.

recorded in the balancing account are just and reasonable, either on a prospective or retrospective basis.

Even if applicants provide such a prima facie showing of justness and reasonableness, Cal Advocates previously noted that there will likely be material disputed facts regarding recorded costs, including:[25]

- Factual disagreements about the CBRs reported by the utility. CBRs rely on estimated benefits, which themselves rely on a number of assumptions, such as the extent to which undergrounding mitigates ignition risk[26] and the extent to which undergrounding reduces the need for power shutoffs.[27]
- Factual disagreements about recorded costs. With billions of dollars at stake, there will be questions about whether the utility's accounts have been properly audited to eliminate accounting errors, double-counting, non-incremental costs, and other mistakes.

The Staff Proposal does not state whether the Commission will review a utility's recorded costs and CBRs in sufficient detail to allay these concerns, nor does it state whether stakeholders will be afforded sufficient access and time to perform an independent review.

The Commission's obligations under PU Code sections 451, 454, and 8388.5 demand strict scrutiny of the costs recorded in the balancing account in order to protect ratepayers from unjust and unreasonable rate increases.[28] The Staff Proposal's omission of the process for review and scrutiny of recorded costs fails to give force and meaning to these statutory obligations. Adoption of SPD-15 without remediation of these issues would therefore constitute a legal error.

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[25] Cal Advocates comments on September 2023 Staff Proposal at 3.

[26] Energy Safety raised concerns with PG&E's estimate for undergrounding effectiveness in its 2023-2025 Wildfire Mitigation Plan. *See*, Energy Safety, *Office of Energy Infrastructure Safety Issuance of Revision Notice for Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, June 22, 2023 at 16.

[27] PG&E has stated that segments that have been undergrounded may still experience outages if upstream segments have not been sufficiently hardened. See PG&E's response to data request CalAdvocates-PGE-2023WMP-14, question 16, April 17, 2023.

[28] "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful." PU Code section 451.

"Except as provided in section 455, a public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified." PU Code section 454(a).

"The commission shall … authorize recovery of recorded costs that are determined to be just and reasonable." PU Code section 8388.5(e)6.

To remediate this legal error, Cal Advocates proposes an appropriate mechanism in Section III.C of these comments. Cal Advocates' proposed mechanism applies robust scrutiny to recorded costs while maintaining the stated aims of Draft Resolution SPD-15 to ensure regulatory certainty, ratepayer protection, and efficient recovery of costs.[29]

### B. The Commission should not allow utilities to record costs in excess of the caps approved in a Phase 2 decision.

The Staff Proposal states that, if a utility incurs costs that exceed the total annual cost cap for the balancing account, it shall record such excess costs in a memorandum account.[30] The utility may then seek recovery of those costs in a Phase 3 application.[31] This process authorizes utilities to record costs far in excess of the conditionally approved caps, with no upper limit. This circumvents the conditional approval in Phase 2 and fails to give any meaningful force to the cost caps.

In addition, the Staff Proposal states that the Commission "will closely scrutinize" costs booked to the memorandum account to "protect ratepayers from unexpected and inefficient cost overruns."[32] However, the Staff Proposal does not describe in any detail the methods the Commission will use to "closely scrutinize" costs. Review of memorandum accounts can be complicated and contentious. Without robust scrutiny, the establishment of a memorandum account for cost overruns effectively amounts to a blank check to the utilities. Ratepayers will shoulder the burden of this blank check through increased rates for decades to come.

The statute requires utilities to demonstrate how costs will decline over time,[33] states that costs will be only conditionally approved,[34] and specifies that only costs that the Commission determines to be just and reasonable will be recovered.[35] The proposed memorandum account for cost overruns allows costs to substantially increase year over year, circumvents the conditional approval in Phase 2, and does not include a robust just and reasonableness review. Draft Resolution SPD-15 does not meet the requirements of the statute and therefore commits legal error.

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[29] Draft Resolution SPD-15 at 6-10.

[30] Staff Proposal at 11.

[31] Staff Proposal at 11.

[32] Staff Proposal at 11. It should be noted that costs in excess of forecasted and conditionally approved caps are unexpected by definition.

[33] PU Code section 8388.5(e)(1)(C).

[34] PU Code section 8388.5(e)(1).

[35] PU Code section 8388.5(e)(6).

### C. The Commission should modify the Staff Proposal to protect ratepayers.

SB 884 requires that the Commission establish a cost-recovery structure that requires utilities to achieve meaningful and timely reductions in wildfire risk at just and reasonable costs to ratepayers. This is consistent with the Commission's obligation to protect ratepayers by authorizing only those costs that are deemed just and reasonable.[36] Below, Cal Advocates proposes an alternative cost recovery mechanism that will protect ratepayers and allow utilities to achieve meaningful and timely reductions in wildfire risk without undue burden.

#### 1. The Commission should review all recorded costs through application proceedings.

The Commission should direct participating utilities to record *all* costs of their SB 884 plans in a memorandum account. To comport with the requirements of SB 884, the Commission should place firm conditions on the costs eligible to be recorded and should cap the total amount that a utility can record in the memorandum account each year. The Commission should then require utilities to seek recovery of costs by filing applications in Phase 3.[37]

An application proceeding provides an appropriate venue for the Commission to review all recorded costs to ensure they are just and reasonable, before authorizing recovery. This process complies with the requirement of SB 884 that the Commission only "authorize recovery of recorded costs that are determined to be just and reasonable."[38]

#### 2. The Commission should adopt an expedited review process for Phase 3 applications.

To meet the stated goals in Draft Resolution SPD-15 of safeguarding ratepayers while allowing utilities to recover costs "without undue delays,"[39] Cal Advocates proposes the following requirements for Phase 3 applications, on a timeframe similar to a catastrophic wildfire proceeding:[40]

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[36] "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable." PU Code section 451.

"The commission shall … authorize recovery of recorded costs that are determined to be just and reasonable." PU Code section 8388.5(e)(6).

[37] Staff Proposal at 10-12.

[38] PU Code section 8388.5(e)(6).

[39] Draft Resolution SPD-15 at 6-10.

[40] PU Code section 1701.8.

- Costs recorded in the memorandum account shall conform to the total annual cost cap, average unit cost cap, and average minimum CBR adopted in a Phase 2 Decision.
- If incurred costs meet some but not all of these three conditions, the utility shall exclude (from its cost-recovery request) the portion of costs necessary to bring the recorded costs into compliance with all three conditions.
- A Phase 3 application for recovery of costs recorded in the memorandum account shall be approved or denied within ten months. This timeframe balances efficiency with effective oversight.
- It is presumed that evidentiary hearings will be unnecessary unless substantive concerns are raised in the first two months of the proceeding. If so, the Phase 3 application timeline may be extended by three months to allow for hearings.
- To facilitate the accelerated schedule, during the Phase 3 application period, all parties must respond to discovery requests within five business days.[41]
- A utility may file no more than one Phase 3 application each calendar year.[42]

#### 3. The Commission should adopt an expedited process for petitions for modification to adjust cost caps and CBR minimums.

Cal Advocates recognizes that a ten-year plan carries significant uncertainty. To account for the inherent uncertainties of this timeframe, the utilities can file a petition for modification (PFM) of the Phase 2 decision to request adjustments to the cost caps and CBR thresholds. Such a PFM should clearly discuss the need to modify the Phase 2 decision, consistent with the requirements of Rule 16.4.[43] This process, which already is afforded any party pursuant to the Commission's existing rules, will allow the Commission and stakeholders the opportunity to review the utility's updated forecasts and ensure the requested costs are just and reasonable on an *ex ante* basis, prior to the utility incurring the costs. This would provide utilities the flexibility needed to adapt to changing circumstances while maintaining robust ratepayer protections.

Cal Advocates proposes that the following stipulations shall apply to SB 884 PFMs:

- The Commission should approve or deny the PFM within six months.

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[41] Staff Proposal at 4.

[42] Staff Proposal at 11.

[43] California Public Utilities Commission, *Rules of Practice and Procedure* modified May 1, 2021 at 90.

- Once a utility's cost caps and/or CBR thresholds are revised, they should not be changed again for a minimum of 12 months.
- In the petition, the petitioner must provide all facts and evidence necessary to substantiate its request. Otherwise, the Commission should reject the PFM without prejudice.
- Within 45 days of filing,[44] the assigned administrative law judge (ALJ) should convene a pre-hearing conference, issue questions for parties to address in initial comments, or both.
- The assigned ALJ should issue a schedule that calls for party comments or testimony approximately three months after filing, with reply comments or rebuttal testimony one month thereafter. This provides a reasonable amount of time for party discovery and analysis of the request.
- To facilitate the expedited schedule, during the review of a PFM, parties shall respond to discovery requests within five business days.[45]

#### 4. Cal Advocates' proposal is reasonable and ensures robust ratepayer protection without placing an undue burden on utilities.

Cal Advocates' proposed cost recovery structure would ensure the Commission meets its statutory obligations to ensure just and reasonable rates. Additionally, this approach would give force and meaning to the stated intents of Draft Resolution SPD-15 while not imposing an undue burden on utilities. At its core, Cal Advocates' proposal provides for:[46]

- *Expedited Review*:
    - Cal Advocates' proposed approach sets clear expectations for the timeline of a cost recovery application and allows for timely recovery of incurred costs.
    - This approach also allows for an expedited review of PFMs if modifications to the Phase 2 Decision are needed to address uncertainties throughout the ten-year plan.
- *Regulatory Certainty*:
    - Cal Advocates' proposed approach establishes transparent conditions and clear timelines under which costs may be recovered and strict, transparent conditions that incurred costs must meet for recovery.
    - The expedited PFM process allows utilities to address uncertainty without sacrificing ratepayer protections.

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[44] Rule 16.4(f) of the Rules of Practice and Procedure provides 30 days for responses to a PFM and allows 10 days for replies.

[45] Staff Proposal at 4.

[46] Draft Resolution SPD-15 at 6-10.

- *Ratepayer Protection*:
    - Cal Advocates' proposed approach subjects all SB 884 costs to public review and regulatory oversight to ensure costs are just and reasonable.
    - The strict cost caps and CBR minimums protect ratepayers from unexpected rate increases that could result from uncapped cost overruns, while allowing utilities flexibility through the accelerated PFM process.

Cal Advocates' proposal alleviates the legal and procedural flaws of the Staff Proposal. The Commission should modify the Staff Proposal to adopt our recommended cost recovery approach.

## IV. The Commission and Energy Safety should coordinate their actions in order to successfully achieve the goals of SB 884.

The Staff Proposal makes clear throughout that Energy Safety and the Commission have defined roles and responsibilities as specified in SB 884. The Staff Proposal discusses these roles, lays out the sequential nature of the agency interaction with a utility's Plan, and acknowledges that the two agencies expect to coordinate on the following items:[47]

- Project Data Requirements,[48]
- Alignment of Progress Report requirements,[49] and
- Procedures for considering a large electrical corporation's request to change elements of its Plan.[50]

The coordination areas identified in the Staff Proposal are by no means an exhaustive list of material issues that must be resolved for a utility to craft a Plan that "substantially increase[s] electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and any other outage programs, and substantially reduce[s] the risk of wildfire,"[51] subject to approval by Energy Safety and a favorable decision from the Commission.

### A. The Commission and Energy Safety should develop a common set of terms and definitions.

In addition to the three areas discussed above that the Staff Proposal identified for future coordination with Energy Safety, Cal Advocates recommends that the two agencies also coordinate on the following:

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[47] See footnotes 14, 16, and 22 of the Staff Proposal.

[48] Staff Proposal at 9 and Appendix 1.

[49] Staff Proposal at 13.

[50] Staff Proposal at 13.

[51] PU Code section 8388.5(d)(2).

- Define "project"[52] and other standardized terms (e.g., when to refer to an underground mile versus an overhead mile),
- Develop cost efficiency metrics,[53]
- Determine which elements to include in the Plan that will affect the application, such as data about proposed projects, project timelines, analysis of alternatives, and cost forecasts.

Commission staff should collaborate with Energy Safety to develop an appendix of definitions that are fundamental to SB 884 Plans. In addition to a common set of terms and definitions, a common understanding of metrics and elements in a Plan will provide clarity and promote efficiency for applicants and reviewers.

### B. The Commission and Energy Safety should coordinate to avoid backwards incompatibility.

Although the Staff Proposal addresses potential "changes to the plan"[54] and the expectation of future coordination, the Commission and Energy Safety need to determine what will happen if the Commission directs the utility to modify its Plan after it has been approved by Energy Safety. During Phase 1, Energy Safety will review and approve a utility's Plan.[55] During Phase 2, the Commission will review the plan and its costs through an application proceeding.[56] As part of Phase 2, the Commission could order a utility to substantively modify its application in a way that requires modification of the Plan previously approved by Energy Safety.[57]

The guidance documents developed by each agency should describe a transparent and public process that each agency will follow if this occurs. Because the statute requires an expedited,

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[52] Cal Advocates outlined three key principles that should be used to define a project: 1) a project is a contiguous group of comparably high-risk assets that are to be mitigated simultaneously; 2) Risk reduction benefit should be estimated at the scale of the assets to be removed from service; 3) The project should be traceable through all stages of the project lifecycle. See discussion in *Public Advocates Office's Comments on Undergrounding Plan Guidelines*, filed in docket 2023-UPs, November 2, 2023 at 3-7. Available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=55915&shareable=true

[53] Cal Advocates encourages both the Commission and Energy Safety to adopt the cost-benefit ratio (CBR) as the definition of "cost efficiency." The CBR was adopted by the Commission in Decision (D.) 22-12-027 in Rulemaking (R.) 20-07-013, Ordering Paragraph 1 and Appendix A. See discussion in *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.

[54] Staff Proposal at 13.

[55] Staff Proposal at 4; PU Code section 8388.5(d).

[56] Staff Proposal at 4; PU Code section 8388.5(e).

[57] "Before approving the application, the commission may require the large electrical corporation to modify or modify and resubmit the application." PU Code section 8388.5(e)(5).

nine-month review in each phase, every effort must be made by both agencies to ensure that they are reviewing similar information to promote efficiency and to avoid confusion.

### C. The Commission and Energy Safety should leverage the Memorandum of Understanding to support the objectives of SB 884.

Energy Safety and the Commission developed a Memorandum of Understanding (MOU) to coordinate their actions related to "wildfire management and electric infrastructure safety, including, but not limited to, the sharing of information."[58] The MOU's list of shared priorities supports establishing a collaborative working group of agency staff and decision makers to homogenize the Phase 1 and Phase 2 guidelines. The MOU's stated goals include working together to develop consistent policies regarding utility wildfire mitigation; assisting one another in addressing "public safety risks associated with energy infrastructure;" collaborating to assist the Commission in fulfilling its obligations regarding reasonable costs; and collaborating to assist Energy Safety in fulfilling its obligations regarding wildfire safety.[59]

SB 884 plans are likely to commit massive amounts of ratepayer funds, which may easily surpass all other wildfire mitigation strategies combined. Closer coordination between the two agencies in aligning their elements of the SB 884 plans is likely to yield benefits to all stakeholders, including faster and more complete Plan development by utilities, speedy and thorough review by the agencies, and more transparent Plans subject to intervenor and public review. Cal Advocates recommends that the Commission and Energy Safety leverage the MOU to support the objectives of SB 884.[60]

## V. Additional comments

### A. The Commission and Energy Safety should allow stakeholders as well as utilities to request changes to a utility's approved SB 884 Plan.

The Staff Proposal states that procedures governing utility-requested changes to the plan "will be determined by the Commission in coordination with Energy Safety in a subsequent process."[61] Cal Advocates supports the development of coordinated guidelines to govern utility-requested changes

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[58] *Memorandum of Understanding between the California Public Utilities Commission and the Office of Energy Infrastructure Safety*, July 12, 2021 (MOU) at 1, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/20210712-cpucoeis-mousigned.pdf

[59] MOU at 1-2.

[60] *Memorandum of Understanding between the California Public Utilities Commission and the Office of Energy Infrastructure Safety*, July 12, 2021 (MOU) at 1, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/20210712-cpucoeis-mousigned.pdf

[61] Staff Proposal at 13.

to the approved plan.[62] To ensure the updates conform to statutory intent and do not impose unjust or unreasonable costs on ratepayers, the update process should be public, with opportunities for stakeholders to perform discovery and file comments. For regulatory efficiency, the Commission and Energy Safety should consider requiring utilities to update their plans through a PFM, utilizing the guidelines we propose in section III.C of these comments. The Commission and Energy Safety should also allow other parties to use the same process. This will provide a venue for the Commission to revisit the conditional approval if, for example, a utility consistently fails to meet its mileage targets or new technologies become preferable to undergrounding for cost-efficient and swift wildfire mitigation.

### B. The Commission should require utilities to employ reasonable and comparable assumptions in their analyses of alternative mitigations.

PU Code Section 8388.5(c)(4) states that a utility's SB 884 plan shall include "a comparison of undergrounding versus aboveground hardening of electrical infrastructure and wildfire mitigation for achieving comparable risk reduction, or any other alternative mitigation strategy."[63] To address this requirement, the Staff Proposal requires utilities to provide "the forecasted CBRs across all projects … for alternative wildfire mitigation hardening methods considered, in place of undergrounding."[64]

However, the Staff Proposal does not require that utilities calculate these alternate CBRs using similar assumptions to those used for undergrounding. This omission is a legal and technical error because it does not provide for a valid and reasonable comparison between undergrounding and the alternatives.

As Cal Advocates previously noted, utilities have in the past used assumptions that do not lead to a fair and accurate comparison of the alternatives. In its 2023-2025 Wildfire Mitigation Plan (WMP), PG&E's comparison of overhead and underground system hardening assumed that the unit cost of undergrounding would decrease over time, while the unit cost of covered conductor would increase over time.[65] These assumptions arose from the utility's plan to increase undergrounding

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[62] See discussion in Cal Advocates comments on September 2023 Staff Proposal at 14-15.

[63] PU Code section 8388.5(c)(4).

[64] Staff Proposal at 8, application requirement #9.

[65] See discussion in *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 15.

mileage and to decrease covered conductor mileage.[66] In other words, PG&E pre-determined its preferred mitigation strategy, used that strategy to influence its unit cost calculations, and then used those calculations to justify its pre-determined choice of mitigation measure.

In the situation described above, PG&E did not use reasonable and comparable assumptions to evaluate alternative mitigations to undergrounding. If a utility were to take a similar approach in an SB 884 application, it would artificially decrease the estimated CBR of alternative mitigations, leading to approval of undergrounding for locations that (with a fair comparison) would be better suited to cheaper and faster wildfire mitigation methods.

The Staff Proposal should be modified to require utilities to use reasonable and comparable assumptions in their calculations of CBRs for both undergrounding and alternative mitigations. Failure to do so could result in flawed, misleading analyses that would be technically flawed and also would not meet the statutory intent of PU Code Section 8388.5(c)(4).[67] It would therefore constitute both a technical and legal error.

### C. The Commission should improve the Staff Proposal's requirements regarding impacts on telecommunications utilities.

The Staff Proposal contains several useful provisions that require electric utilities to describe how their SB 884 plans will affect telecommunications providers. For example, the Staff Proposal states that applications must address coordination with telecommunications providers on the ownership or use of poles affected by proposed undergrounding projects.[68]

However, the Commission should revise the Staff Proposal to improve these requirements. First, the Commission should require participating electric utilities to provide a copy of the SB 884 application to each telecommunications utility that has equipment on poles where undergrounding is planned. Second, the Commission should require participating electric utilities to describe in detail how it will address the affected shared poles (including who will own and maintain the poles if the

[66] In response to data request CalAdvocates-PGE-2023WMP-09, April 7, 2023, question 13, attachment 1, PG&E provided calculations supporting its estimated risk-spend efficiencies (RSE). The RSEs in this document cannot be directly compared, since PG&E's forecast unit cost for overhead system hardening in this attachment ranges from $1.56 million per mile to $1.67 million per mile, nearly double PG&E's *actual* unit cost in 2022 of $0.83 million per mile (PG&E, *2023-2025 Wildfire Mitigation Plan R1*, April 6, 2023, Table PG&E-22-11-3 at 903).

Per PG&E's response to data request CalAdvocates-PGE-2023WMP-22, May 5, 2023, question 4, these increased costs are due to "an assumed loss of economies of scale" related to its planned reduction in overhead hardening miles.

[67] PU Code section 8388.5(c)(4).

[68] Staff Proposal at 9-10, application requirements 12 and 17.

existing communications infrastructure is not placed underground). Third, if an electric utility transfers ownership of poles to a telecommunications utility, the Commission should require the electric utility to remove those poles from its rate base (to eliminate any further depreciation costs to electric customers). This will ensure that utility ratepayers are not charged for depreciation of the same assets from both the electric and telecommunication utilities.

## VI. CONCLUSION

Cal Advocates respectfully requests that the Commission adopt the recommendations discussed herein.

Respectfully submitted,

/s/ Nathaniel Skinner

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December 28, 2023

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Fred Hanes, Safety Policy Division
SB 884 Service List
Caroline Thomas Jacobs, Office of Energy Infrastructure Safety
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Gary Chen
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December 28, 2023

Rachel Peterson
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

**SUBJECT: Southern California Edison Company's Opening Comments on Draft Resolution SPD-15**

Dear Executive Director Peterson:

Southern California Edison Company (SCE) provides the following comments on Draft Resolution SPD-15 (Draft Resolution), which would adopt Safety Policy Division's (SPD) Staff Proposal for the Senate Bill 884 (SB 884) expedited utility distribution infrastructure undergrounding program (Staff Proposal). The Staff Proposal addresses the process and requirements for the California Public Utilities Commission's (Commission) review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan (Plan) and its related costs.

SCE appreciates the opportunity to provide comments on the Draft Resolution and accompanying Staff Proposal. SCE's comments focus on two key topics: (1) clarifying the proper use of cost-benefit ratios in light of prior Commission precedent, and (2) the contemplated use of annual metrics to assess multi-year undergrounding projects. If SCE has not commented on a particular subject, that should not be interpreted as agreement on that subject area.

**THE DRAFT RESOLUTION SHOULD CLARIFY THAT COST-BENEFIT RATIOS DO NOT SERVE AS THE SOLE DETERMINANT FOR SELECTING AND IMPLEMENTING RISK MITIGATIONS**

The Draft Resolution notes that the Staff Proposal establishes "an annual minimum cost-benefit ratio (CBR) threshold for projects completed and booked to the one-way balancing account" that would be established to recover costs related to an SB 884 plan.[1] The Draft Resolution also provides that the "'threshold CBR value' will establish the minimum CBR that must be achieved for cost recovery."[2] Similarly, the Staff Proposal provides that one of the conditions for approval of an SB 884 plan's costs is that the "average recorded CBR for all projects completed in any given year

[1] Draft Resolution, p. 9.
[2] Draft Resolution, p. 10, n. 6; Staff Proposal, p. 10, n. 20.

must equal or exceed the threshold CBR value for that year."[3] The Draft Resolution states that establishing an annual minimum cost-benefit ratio "conforms to the Commission's current methods for risk-based decision making."[4]

To the extent that the Draft Resolution and/or Staff Proposal contemplate using a cost-benefit ratio as a dispositive factor or minimum threshold in determining whether undergrounding as a proposed mitigation is reasonable and eligible for cost recovery, such an approach directly conflicts with the express language of the decision cited in the Draft Resolution and Staff Proposal and should be clarified.[5] The Commission has repeatedly and consistently confirmed that risk spend efficiencies (RSEs)—or their cost-benefit ratio derivatives—are only one of many factors that may be used in assessing risk mitigations, and that neither RSEs nor cost-benefit ratios are intended to serve as the sole determining factor in assessing whether a proposed mitigation selection is reasonable.[6] For example, in the rulemaking to further develop a risk-based decision-making framework (R.20-07-013) (Risk OIR), the Commission highlighted that "we do not intend that the Cost-Benefit Ratios produced using this method must serve as the sole determinants of IOU proposals or Commission decisions on risk Mitigations."[7] The decision also provides that "[m]itigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis."[8]

The decision in the Risk OIR that is cited in the Draft Resolution correctly recognized that cost-benefit ratios are not and should not be the only factor used to develop a proposed risk mitigation such as targeted undergrounding.[9] There are absolute risk issues that may not be captured by the cost-benefit ratios including the crucial topic of risk tolerance, as well as a multitude of ethical, socioeconomic, compliance, and physical and resource constraints which are not readily translatable to dollar values, but which are critical to the sophisticated process of actually managing resources, risks, and service. Employing a "minimum cost-benefit ratio threshold" fails to take into account several factors that the Commission has recognized may also be considered by utilities when selecting their portfolio of wildfire mitigation initiatives.

Further, reducing risk mitigation decisions to a single factor like cost-benefit ratios assumes an unrealistic level of precision and accuracy in models. Though California utilities have been significantly engaged with the Office of Energy Infrastructure Safety (OEIS) on improving risk models, the underlying data is not always complete and/or accurate or otherwise able to fully capture the complete picture of wildfire risk at a particular location. Additionally, quantitative risk

[3] Staff Proposal, p. 10.
[4] Draft Resolution, p. 9.
[5] *See* D.22-12-027 in R.20-07-013.
[6] D.22-12-027 at 26, 56.
[7] D.22-12-027 at 26; *see also id.* at 27. ("The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach.").
[8] *Id.* at 27.
[9] *Id.* at 26-27.

models may not fully capture important qualitative factors that affect risk mitigation decisions. Risk mitigation is too important to public safety to boil down to a single factor.

SCE requests that the final resolution and Staff Proposal clarify that cost-benefit ratios are one factor among many in assessing risk mitigations, and that the resolution is not intended to supplant Commission precedent confirming that cost-benefit ratios are not to be used as the sole determining factor in assessing whether a proposed mitigation selection is reasonable.

**PROJECT METRICS SHOULD NOT BE OVERLY PRESCRIPTIVE OR MEASURED ON A SHORT-TERM TIMEFRAME**

The Draft Resolution restates the Staff Proposal provisions setting parameters to evaluate Plan costs, including "[e]stablishing an annual cost cap for Plan costs booked to the one-way balancing account"[10] and "[e]stablishing an annual minimum cost-benefit ratio (CBR) threshold for projects completed and booked to the one-way balancing account."[11] Objections to minimum CBR thresholds notwithstanding (discussed above), measuring annual metrics for multi-year undergrounding projects can be challenging and not as meaningful as intended.

For instance, if a project is completed faster than anticipated or is delayed for any number of not-uncommon, often exogenous reasons, one year's average annual CBR or annual cost cap could be exceeded or underrun, despite no actual change in a project's or the overall Plan's costs or risk buydown. SCE recommends measuring such metrics on a longer time horizon, which would allow for meaningful Plan oversight that isn't unduly swayed by unforeseeable timing changes and allows a completed project to be evaluated in its entirety.

**CONCLUSION**

SCE appreciates the opportunity to provide comments on the Draft Resolution and looks forward to continuing to work with the Commission, the Office of Energy Infrastructure Safety, and other stakeholders on this matter. If you have questions or require additional information, please contact me at gary.chen@sce.com.

Sincerely,

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

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[10] Draft Resolution, p. 8.
[11] Draft Resolution, p. 9.

CC: Chirag “CJ” Patel, Senior Utilities Engineer, Risk Assessment and Safety Analytics Section, Safety Policy Division, Chirag.Patel@cpuc.ca.gov
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SB-884 Notification List
Service Lists for A.21-06-021, A.23-05-010, and A.22-05-016

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December 28, 2023

Energy Division Tariff Unit
California Public Utilities Commission
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**RE: SDG&E Comments on Draft Resolution SPD-15**

Dear Energy Division Tariff Unit:

In accordance with Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), San Diego Gas & Electric Company (SDG&E) respectfully submits these comments on Draft Resolution SPD-15.

## I. INTRODUCTION

SDG&E provides the following comments on Draft Resolution SPD-15 and California Public Utilities Commission Safety Policy Division's (SPD) Staff Proposal addressing the Senate Bill (SB) 884 expedited undergrounding program. The Staff Proposal provides additional detail regarding the process and requirements for the Commission's review upon receiving an electrical corporation's ten-year distribution infrastructure undergrounding plan (Program).

SDG&E's comments to the Draft Resolution and Staff Proposal focus on the need for additional flexibility given the complexity of and long-term planning associated with a long-term undergrounding plan. Namely, both the accounting mechanisms and the overly restrictive application of the cost-benefit metrics unreasonably fail to allow any adjustments based on what may be reasonable and necessary changes to risk analyses, undergrounding strategies, or program costs—some of which may be mandated by applicable regulations or laws.

## II. DISCUSSION

### A. <u>Cost Accounting and Recovery</u>

SDG&E appreciates the Draft Resolution and Staff Proposal updates to allow for a two-step recovery process, including both the one-way balancing account for recording approved annual costs and a mechanism to record and potentially recover reasonable additional costs incurred above the annual cost cap. SDG&E supports this cost recovery mechanism but finds additional areas that should be clarified or addressed in the final Resolution and Staff Proposal. These include: (1) clarifying the definition of "average recorded" costs for the unit cost cap; (2) using only completed projects in the average unit cost cap calculation; (3) allowing for the use of the memorandum account for costs in excess of the cost cap; and (4) allowing for cost recovery of abandoned projects.

### 1. Average Recorded Unit Cost Cap

The unit cost cap is described differently within the Draft Resolution and the Staff Proposal. SDG&E recommends that the Draft Resolution language be modified to align with the Staff Proposal language. The Draft Resolution states that costs booked to the one-way balancing account will not be recovered in any given year, "if the unit costs for such projects exceed a known value."[1] However, the Staff Proposal states, "average recorded unit costs in any given year must not exceed the approved unit cost target for that year."[2] SDG&E believes the electric corporation should be held to the average annual unit cost, which allows the utility to balance difficult higher-cost projects which may exceed the average annual unit cost with other lower cost projects. The ability to average unit costs is necessary to allow the electrical corporations to perform the portfolio of work necessary to reach its goals involving wildfire risk reduction and reliability improvements. It would be unreasonable and contrary to the nature of a large-scale undergrounding approach to hold each project to a single unit cost cap as implied by the language in the Draft Resolution.

### 2. Completed Project Costs

The Staff Proposal states that "average recorded unit cost in any given year must not exceed the approved unit cost target for that year"[3] but does not clarify which costs are included in the calculation of the average recorded unit cost. To accurately capture the unit costs associated with a full undergrounding project, SDG&E believes that only the costs associated with completed projects should be utilized for this calculation. SDG&E recommends that all costs associated with a given project, regardless of when these costs were incurred, would be included in the average unit cost calculation in the year the project is completed. Undergrounding projects

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[1] Draft Resolution, p.9.
[2] Staff Proposal, p.10.
[3] Staff Proposal, p.10.

will likely span multiple calendar years. In the early phases of a project, engineering, permitting, and design costs are significantly less than costs incurred in later years to complete construction. Therefore, to accurately capture a project's unit cost all costs should be considered once the project is completed and becomes used and useful.

### 3. Memorandum Account for Costs Exceeding Cost Cap

As stated above, a ten-year undergrounding plan may include a wide range of projects, including difficult construction projects that may pose higher costs but are important for the electric corporation to complete in order to achieve its wildfire risk reduction and reliability goals. SDG&E does not believe that these projects should be denied recovery due to timing issues or other unavoidable delays that may impact construction. Instead, project costs that exceed the unit cost cap should be allowed to be booked to the memorandum account for further review. This approach will allow the electric corporation flexibility to complete necessary projects even if delays or other unforeseen circumstances push the unit cost higher than expected, while protecting ratepayers by ensuring costs exceeding the cap are reviewed for reasonableness.

### 4. Abandoned Project Costs

The Draft Resolution establishes a process for recovering costs associated with undergrounding projects once the project is completed. However, due to the ongoing refinement of risk models, the uncertainty of permitting and land acquisition, or other unforeseen circumstances, an electrical corporation may begin work on a project but ultimately elect not to complete construction. In these instances, the Draft Resolution should include language that allows for these abandoned project costs to be captured within the memorandum account for reasonableness review by the Commission.

## III. INCLUSION OF NON-HFTD UNDERGROUNDING MILES

The Draft Resolution currently only allows for cost recovery of projects located in Tier 2 or Tier 3 of the high-fire threat district (HFTD) or within wildfire rebuild areas.[4] Due to the nature of undergrounding construction, such a provision may inadvertently impose an unreasonable restriction on the electrical corporations' ability to reduce wildfire and PSPS risk. Circuits scoped for undergrounding will likely cross boundaries between the HFTD and non-HFTD areas. If a project meets the risk reduction goals outlined in an approved undergrounding plan, the non-HFTD miles associated with these projects should be allowed recovery. There may be scenarios

[4] Draft Resolution, p.2.

where leaving a small portion of the undergrounded circuit overhead may not be reasonable or would result in unaddressed risk. The Draft Resolution should account for these instances. Additionally, there may be areas outside the HFTD within the wildland urban interface or other coastal canyon areas that could benefit from undergrounding, especially as our understanding of climate change and other factors are included within the risk models. The Draft Resolution should be modified to allow the electric corporations to justify undergrounding scope outside of the HFTD and inclusion of non-HFTD miles in the Plan.

## IV. THE COMMISSION SHOULD ALLOW FOR CONSIDERATION OF METRICS OUTSIDE OF COST-BENEFIT RATIOS

The Staff Proposal requests that an electrical corporation's SB 884 application include forecasted average full-program and annual cost-benefit ratios for undergrounding projects,[5] and states that if an electrical corporation does not achieve its approved forecast of average CBR, "cost recovery will be denied for as many projects as necessary to bring the recorded CBR average up to the approved target."[6] The CBR concept is an outcome of the Commission's Risk-Based Decision-Making Framework (RBDMF) proceeding.[7] While the Cost-Benefit Approach is helpful in assessing the reasonableness of a proposal, the Commission has stated that it does not intend CBR to be the "sole determinant" of risk mitigation strategies.[8] Further, a Program application will not be comparing risk mitigation strategies across the entire risk portfolio, as would occur during the Risk Assessment Mitigation Phase (RAMP) proceeding.

Additionally, the RBDMF proceeding is ongoing, and the value of benefit is not yet clearly defined. SDG&E requests that the Staff Proposal remove the overly prescriptive use of CBRs and provide additional flexibility to assess the full scope of risk reduction and benefits of undergrounding projects.

## V. COMMUNICATION COMPANIES

The Draft Resolution provides that an electrical corporation address efforts to work with communications companies regarding co-trenching and land rights. The language of the Draft Resolution seems based on the premise that communication providers have acquired their own

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[5] Staff Proposal, p.8.

[6] Staff Proposal, p.10.
[7] Rulemaking (R.) 20-07-013.
[8] Decision (D.) 22-12-027, p. 26.

underlying land rights from the property owner to maintain their facilities. The electrical corporations have varied relationships and land rights arrangements with their respective communications companies, and the presumptions implied by the language of the Draft Resolution regarding property rights may not always apply. SDG&E does not necessarily object to the current language regarding communications providers, but the Commission may consider clarifying the language to reflect the various land rights arrangements of the communications providers.

## VI. CONCLUSION

SDG&E appreciates the CPUC's consideration of these comments on the Staff Proposal, and requests that the CPUC take these recommendations into account in further refining the Staff Proposal.

Sincerely,

*/s/ Clay Faber*
CLAY FABER
Director – Regulatory Affairs

cc: Meredith Allen – Pacific Gas & Electric
Connor Flanigan – Southern California Edison Company
Shivani Sidhar – San Diego Gas & Electric Company
Chirag Patel – California Public Utilities Commission
Fred Hanes – California Public Utilities Commission
Koko Tomassian – California Public Utilities Commission
Taaru Chawla – California Public Utilities Commission
Julian Enis – California Public Utilities Commission
Jason Ortego – California Public Utilities Commission
Matthew Coldwell – California Public Utilities Commission
SB884 Notification List
Service List A.21-06-021, A.23-05-010 and A.22-05-016

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

December 28, 2023 Via Electronic Service

Rachel Peterson, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
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**Re: MUSSEY GRADE ROAD ALLIANCE COMMENTS ON DRAFT RESOLUTION SPD-15 AND THE STAFF PROPOSAL FOR THE SB 884 PROGRAM**

Dear Executive Director Peterson,

The Mussey Grade Road Alliance (MGRA or Alliance) respectfully submits the following comments on Draft Resolution SPD-15 for the SB 884 Program. Comments have been prepared by Alliance Expert Witness Joseph W. Mitchell, Ph.D.

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

Respectfully submitted,

/s/ *Diane Conklin*


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Dated: December 28, 2023

# 1. INTRODUCTION

## 1.1. History

Senate Bill 884 was introduced in the summer of 2022 in order to expedite the long term planning of utility undergrounding and hardening projects.[1] The Alliance expert and others immediately saw potential issues in the proposed bill that would risk both safety and affordability in the state. MGRA's expert, in fact, wrote a letter to the governor opposing the bill in September of 2022. After the bill was adopted as Public Utilities Code § 8388.5, MGRA has participated in workshops and meetings with OEIS, SPD, and stakeholders as rules for implementing the law have been discussed and developed. These plans have now entered the comment phase and the Alliance respectfully asks both the Commission and the OEIS to consider its input.

Draft resolution SPD-15[2] was served on November 9, 2023 with a due date for Comments on December 28, 2023. This Draft Resolution was served on the SB 884 notification list and service lists of A.21-06-021, A.23-05-010, and A.22-05-016.

# 2. MGRA COMMENTS ON ISSUES

## 2.1. Issues in Common with Cal Advocates and TURN

MGRA has collaborated closely with Cal Advocates and TURN throughout the SB884 undergrounding plan development process and strongly supports suggestions and comments of these stakeholders. We particularly note their positions that:

- Rules for regulating undergrounding plans by OEIS and the Commission must be closely coordinated and synchronized, and that since the OEIS evaluation of undergrounding plans will precede Commission review, the OEIS rules should be established prior to the Commission rules and the Commission rules should maintain consistency with the OEIS rules. Hence, the present deadline for SPD-15 is

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[1] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB884

[2] Draft Resolution SPD-15; November 9, 2023.

premature and resolution should be postponed until after OEIS has finalized its own regulations.

- The Commission should ensure that sufficient regulatory mechanisms are in place to ensure just and reasonable rates for ratepayers, and that utilities are not permitted to enjoy a windfall from these programs.
- A strong auditing process must be in place to ensure that utilities provide promised risk reduction to ratepayers at the promised cost.

**2.2. MGRA Specific Comments**

In addition to its support of the comprehensive TURN and Cal Advocates comments, MGRA has a number of additional comments and observations that should be incorporated into the regulations governing the undergrounding plans to ensure that they do result in excess costs to ratepayers, reduction in safety for certain residents, and provide increased flexibility to incorporate new information as it becomes available.

- **Uncertainty, error, and change in utility risk analyses**

MGRA has been heavily involved in utility safety proceedings at both the OEIS (in WMP analysis) and the CPUC (General Rate Cases and RAMP proceedings). As a general statement, it is inarguable that the utility approaches to risk are changing and evolving rapidly. For example, results from PG&E's WDRM v2 and WDRM v3 risk models produced radically different model results.[3] Utilities continue to incorporate new information as it becomes available, and for the most part these changes are evolutionary improvements. However, the fact that the utility risk estimates are mutable raises fundamental questions about how they can be utilized to project accurate ten-year hardening plans as required by Public Utilities Code § 8388.5.

The utilities cannot at this point claim that their current plans are now "fixed" and that future changes should be relatively small. There remain a number of errors, inaccuracies, and flaws with the current risk models that MGRA has raised in both WMP and GRC cycle analysis, and which its

[3] D.23-11-069; p. 282.

expert recently published in a paper in a refereed fire science journal.[4] Major issues currently still plaguing utility risk models and under active study by utilities, the Commission, and OEIS include:

- The current 8 hour duration used by utilities for wildfire spread modeling puts a cap on the maximum fire loss that is considerably less than those observed in major utility wildfires.[5] This creates a bias that amplifies risks from nearby ignitions and suppresses risk from distant ignitions.
- Machine learning models used for planning hardening projects aggregate weather variables and therefore do not correctly predict the drivers that are responsible for catastrophic fires, overweighting ignitions from external agents (animals, vehicles, balloons, 3rd parties) at the expense of weather related drivers such as equipment damage and vegetation contact.[6]
- Because utility models use past ignitions or outages to predict future wildfire risk, use of PSPS will cause areas most subject to PSPS to be underrepresented in risk models because data is not collected during the most dangerous periods.[7]
- Utilities do not incorporate wildfire smoke risk, which based upon recent research may be responsible for more injuries and fatalities that wildfire itself.[8]
- Covered conductor, based on data from the SCE deployment, seems to have a higher efficiency in preventing catastrophic wildfire ignitions than has been presented by other utilities.

This is not a complete list of biases and errors in utility wildfire modeling. Because utilities continue to improve their models and we expect that over time a number of these errors will be corrected, it must be anticipated that relative risk ranking of circuits and absolute measures of wildfire risk will evolve over time. It is therefore not possible to ensure that a wildfire mitigation plan with a ten-year timeline as envisaged by Public Utilities Code § 8388.5 will be accurate over the lifetime of the plan. Mechanisms need to be built in to allow flexibility.

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[4] Mitchell, J.W., 2023. Analysis of utility wildfire risk assessments and mitigations in California. Fire Safety Journal 140, 103879. https://doi.org/10.1016/j.firesaf.2023.103879
[5] MUSSEY GRADE ROAD ALLIANCE COMMENTS ON 2023-2025 WILDFIRE MITIGATION PLANS OF PG&E, SCE, AND SDG&E; May 26, 2023; pp. 39-42. (MGRA 2023 WMP Comments)
[6] MUSSEY GRADE ROAD ALLIANCE COMMENTS ON 2022 WILDFIRE MITIGATION PLANS OF PG&E, SCE, AND SDG&E; April 11, 2022; pp. 17-40. (MGRA 2022 WMP Comments)
[7] MGRA 2023 WMP Comments; p. 65.
[8] Id; p. 23.

### 2.3. Advanced technologies and covered conductor

In addition to covered conductor, a range of advanced technologies are in some stage of development at the three utilities, including REFCL (Rapid Earth Fault Current Limiter), ECCVM Sensors, RF Sensors, ED, APP, FCD (Falling Conductor Detection), and others. Some of these technologies compliment the already high protection offered by covered conductor, yielding protections approaching undergrounding at a much lower cost.

In PG&E's rate case "*The Commission finds that new emerging technologies, such as REFCL, may in the near future enable PG&E to reduce the risk of wildfire caused by its overhead assets at a significantly lower costs than undergrounding. Because new technologies are emerging that may be highly effective at reducing ignition risks and much less costly, these developments weigh against authorizing a $5.9 billion forecast to support an ambitious plan to underground 2,000 miles when emerging technology may soon present a more attractive alternative for ratepayers in terms of safety and costs*."[9]

Public Utilities Code § 8388.5(c)(4) specifically calls out comparison with these technologies as a component of a complete undergrounding plan. However, as noted in the previous section, utility risk models should be expected to continue to evolve and change over time, and so should the predicted capabilities and costs of alternative technologies. Hence it is not reasonable to expect a calculation of the wildfire reduction efficiency of Advanced Technologies + Covered Conductor to be accurate over a period of ten years.

Regulators must als recognize that there is an inherent moral hazard with regard to utility capital spending, since utilities make a 10% revenue requirement off of this spending. This bias may lead utilities to "slow walk" advanced technology projects that potentially interfere or compete with undergrounding, and to underestimate their effectiveness. Also, with changing models and data, the proper choice of mitigation and priority should be expected to be very different in 2025 than it will be in 2029 – if the utilities are required to do these calculations correctly.

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[9] D.23-11-069; pp. 294-294.

**2.4. Affordability and links to safety and health for poor and vulnerable populations**

An analysis that MGRA has been presenting in its recent WMP and GRC filings and which has not yet been successfully refuted in any forum is the relationship between utility rates and increased mortality of the poorest quintile of the population.

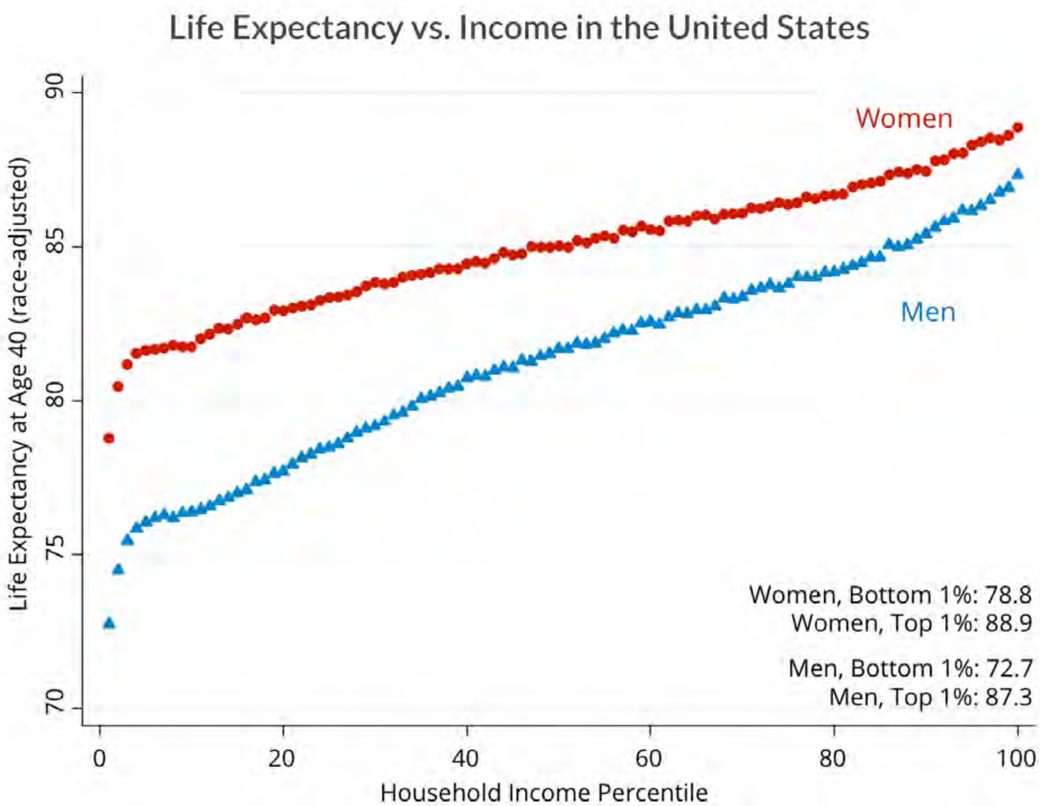


**Figure 1 - Life expectancy versus household income in the US. Data from the Equality of Opportunity Project.**[10]

*"In California, the 20% quintile is equivalent to a household income of approximately $25,000 and a 40% quintile is equivalent to a household income of approximately $50,000.*[11] *For men (chosen for this example due to greater sensitivity of life expectancy to income), there is*

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[10] http://www.equality-of-opportunity.org/health/ and
https://opportunityinsights.org/ citing
The Association Between Income and Life Expectancy in the United States, 2001-2014 | Health Disparities | JAMA | JAMA Network [WWW Document], n.d. URL
https://jamanetwork.com/journals/jama/fullarticle/2513561?guestAccessKey=4023ce75-d0fb-44de-bb6c-8a10a30a6173 (accessed 4.6.22).
[11] https://statisticalatlas.com/state/California/Household-Income

*approximately a three year life expectancy difference between the 20% quintile and the 40% quintile. Hence, in this income range, a difference of around $8000 a year is equivalent of an extra year of life expectancy.*

*If this is the case, then a $300 per year permanent increase in utility rates would cause a $300 decrease in income. This would be correlated with a $300/$8000 or .038 year decrease in life expectancy for this portion of the population. If the poorest 10 million Californians were affected by this change, the number of equivalent years of life lost would be 380,000, or the equivalent of over 5,000 75-year lifespans."*[12]

## 3. RECOMMENDATIONS

In order to ensure that the undergrounding plans and the implementation of SB884's provisions are not in conflict with existing Commission and OEIS regulations, particularly those regarding reasonable service and rates, MGRA recommends that:

- **Clear on/off ramp policies should be in place that allow circuits originally assigned to be undergrounded to be provided with alternate mitigation based on reanalysis of the original data, and vice versa.**
- **Utilities should be required to re-run their analysis of risk and mitigation prioritization every time a major change to models, technologies, or assumptions is made, up to yearly. Results of these analyses should inform the on/off ramps.**
- **Because utility models will be changing frequently, and because it is necessary to audit the end-to-end undergrounding program, utilities will need to maintain historical risk models and compare them against new models as time progresses. This will allow utility performance to be gauged against original commitments.**
- **In the case of high uncertainty, which MGRA argues is true in the current instance, the optimal strategy should be to ensure that the maximum number of residents in high risk areas be provided mitigation as soon as possible and at the least cost. A more elaborate expensive program such as undergrounding, may delay mitigation for those at extreme risk particularly if it is later found that their risk was originally underestimated by utility risk models.**

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[12] MGRA 2021 WMP Comments; pp. 59-60.

- **Regulators should specify benchmarks for utility R&D, pilots, and deployment of advanced technologies in order to reduce the moral hazard faced by utilities who face a strong economic incentive to underground the most conductor possible.**
- **The CPUC should take the lead role with regard to affordability, having a clear legislative mandate in this area while this is less the case for Energy Safety. The CPUC should inform Energy Safety what sort of bounds of utility wildfire prevention spending it will find acceptable so that delays are not introduced in developing a unified plan. The Commission should ensure that they are not merely shifting risk from Wildland Urban Interface Residents onto the poorest and most vulnerable ratepayers.**

Respectfully submitted this 28th day of December, 2023,

By: __/S/____***Diane Conklin***____________________

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**Stakeholder Comments on the**
**SB 884 OEIS Draft Guidelines (10/16/23)**
**and the CPUC SPD staff proposal (9/13/23)**

Robert A. Johnston, Professor Emeritus
University of California, Davis
December 27, 2023

Purpose

I comment here on the staff proposed guidelines from both the OEIS and the CPUC. I do not reference questions from the workshops and I don't reference specific items in these two drafts, because I am concerned mostly with an issue that is inadequately treated. I'll comment mainly on the time period of analysis needed to capture the benefits and costs of undergrounding and otherwise hardening distribution circuits. Then, I'll touch on Spatial Lumping of projects and Metrics to be used in economic evaluation.

A. Time Period of Analysis

SB 884 requires two quite different types of cost analysis and both agencies fail to provide guidelines for both of these methods.

1. The PU Code sec. 8388.5(c)(4) cost and risk reduction analysis is for "the duration of the plan" which will probably be for 10 years. This seems to be conceived as an engineering analysis, which is not appropriate for the examination of long-term costs from wildfires and other changes to the environment. Using circuit-level and segment-level risk factors derived from models based primarily on long-term estimates of wildfire ignitions attempts to include those long-range impacts, but suffers from narrow focus on this one type of impact. That is the mindset of an engineering analysis. These proposed methods are not appropriate for evaluating long-term impacts, but are appropriate for prioritizing projects by degree of wildfire risk reduction.

2. Sec. 8388.5(c)(6), however, requires a quite different type of analysis of costs and benefits "over the life of the assets," which will be 40-80 years normally. PG&E runs a lot of equipment older than 50 years. Benefits here are not limited with any definition and so this brief paragraph seems to mean the sort of benefit-cost analysis required by CPUC Decision 22-12-027 which requires a broad analysis of all costs and benefits in all relevant time periods in CPUC proceedings. Many details are omitted in this Decision, but the method is labelled cost-benefit analysis, which is a well-defined method used worldwide. OEIS should also fulfill the (c)(6)

requirement in this way. Both agencies should use identical cost-benefit techniques for their (c)(6) evaluations, to make their studies and decisions comparable.

I want to emphasize the (c)(6) analysis, because it is barely mentioned in the agency staff proposals. It requires not only the longer time period, but also, as a benefit-cost analysis will project the probable numbers of wildfires and estimate their costs in future years and then discount all data to the base year in the normal fashion for this type of analysis. This is different than the (c)(4) cost analysis that will use circuit-based risk coefficients derived from the utility's wildfire risk model, itself estimated from such data but possibly inaccurately. Benefit-cost analysis uses these same predicted events that the risk model is estimated on, but directly in a fashion the reader can follow. This is a much-more transparent method and so easier to verify and easier for the pubic to understand. And it moves the utilities toward the D.22-12-027 process now required at the CPUC. This benefit-cost analysis method is appropriate for determining if the Plan is cost-effective overall and for determining if Alternatives are more cost-effective than the proposed projects, at the project level and at the plan level.

Benefit-cost analysis literature and Federal agency manuals agree that you look at all costs and all benefits for as long as they occur. Market and non-market costs and benefits of all changes in goods and services must be included. Services includes enjoyment of nature and other hard-to-quantify qualitative experiences. Beyond about 50 years, results are usually not affected by using a longer time period, due to discounting, but that should be tested. Also, discounting doesn't apply logically to lives lost, damage to forests, and other changes and so some sort of totaling over longer time periods is helpful here.

Decision 22-12-027 does not address time period of analysis, but requires the use of the LBL ICE calculation tool (on a web site). The ICE tool caps some inputs at 40 years, implying that the analysis should be likewise capped there. Capping a wildfire risk analysis at 40 years, however, stops the counting of future wildfire starts while undergrounding is still likely being done. The use of a 50-year period would be better.

The staff proposals almost entirely discuss the (c)(4) process. This analysis is limited to the "duration of the plan", which will be 10 yrs or less. This short-term engineering analysis is adequate for the (c)(4) project cost analysis only if the (c)(6) analysis is also done. The largest cost affected by undergrounding and alternatives like insulating distribution lines ("covered conductor") will be the number of wildfire ignitions in the utility's territory caused by utility equipment. For example, in PG&E's territory, there has been a large wildfire every 2-5 years in the last 15 years, usually caused by their ancient and under-maintained equipment. Also, their outdated circuit breaker technology which cannot locate a line break or other equipment failure. These large wildfires have costs in the $10-30 billion range each and so will dwarf all other costs in the (c)(6) analyses. Some of the wildfire costs are not paid by the utilities, but they are still costs in a public benefit-cost analysis.

Here are illustrative calculations. One would expect large differences in future wildfire costs between (1) undergrounding, (2) insulation, and (3) networked computerized breaker systems. Undergrounding has a potential effectiveness of 95%, triple insulation around 70%, and networked breaker systems 50-70% by themselves and 90-99% when combined with insulated lines (data from WMPs, the Joint Utility CC Studies, and the PG&E GRC of 11/16/23). Triple insulation has been tested at SCE in the last few years and found to be 100% effective on the treated circuits, but a lower number is reasonable in the long term. Computerized networked breaker systems are being tested by SCE and by PG&E, but several systems are available and so conclusions regarding costs and effectiveness are a few years off. Some of these breaker systems are in widespread use in Europe.

<u>Whereas their effectiveness seems high or very high, the time periods required to complete these short-circuit mitigation systems are very different.</u> Insulation could be completed for all high fire-hazard areas by any utility in a few years (8-10) and is relatively inexpensive, looking at the SCE cost and completion data in their WMPs. CC can be done during pole replacement, which is otherwise required. Breaker system costs are uncertain, due to low uptake in Calif. and unclear supplies, but are likely to take about 20 years and are relatively inexpensive. This technology needs further testing. Undergrounding, however, is slow due to surface geology issues (rocks), steep slopes, negotiating the ROWs that are needed in most places, and potential lawsuits. ROWs will often be needed beyond existing road ROWs and this necessitates the acquisition of new property rights. Steep terrain also requires the trenching to zig-zag back and forth to make the grade. This increases the line-miles but also requires new ROW and tree removal. So, undergrounding is expensive, about 4X to 7X what insulation costs per line-mile, plus more for the added line-miles (often 50% more). The CEO of PG&E estimated that it would take 50-100 years, as quoted last May in the SF Chronicle, to underground the 10,000 miles then being touted. Another 10,000-15,000 line-miles will be needed, in order to include all lines in high fire-hazard districts. This is a difficult and expensive proposition, coming from a utility with a huge backlog of incomplete repair orders. The completion of Alternatives on time is therefore very important, in order to minimize costs. The much-longer time periods necessary for undergrounding must be property accounted for.

Here are illustrative calculations on Risk-Reduction-Years, as a generic metric. I'm not using official metrics found in the guidelines, but just using a basic risk concept to illustrate the importance of time for plan completion. If a utility can complete insulation in 10 years at 70% effectiveness, they reduce future wildfires by an average of 35% for years 1-10 and by an average of 70% for years 11-50 (see table below). If they add modern breaker systems in a second phase in years 11-20 risk is further reduced by an average of 47% for years 11-20, and then wildfires are virtually eliminated (by 95%) in years 21-50. If they underground and it takes 50 years to complete all lines in high fire-hazard areas, we get an average risk reduction of 47% for years 1-50, assuming a linear function (same line-miles completed per year).

<u>Risk-Reduction-Years (All Totals for 50 Years)(Larger Values Mean Less Risk)</u>
CC Only : (0.35 X 10) + (0.70 X 40) = 3.5 + 28 = <u>31.5</u>
CC plus Breakers: (0.35 X 10) + (0.475 X 10) + (0.95 X 30) = 3.5 + 4.7 + 28.5 = <u>36.7</u>
Undergrounding Only: (0.47 X 50) = <u>23.5</u>
<u>Undergrounding has the lowest risk reduction, due to its slow implementation.</u> Insulation (CC) is superior, due to rapid completion, even though it is less effective per year when completed. Fortunately, CC can be followed by other phase 2 mitigation improvements.

A second conclusion is that following up CC with computerized breakers seems to be a robust Alternative. This is because the projections on which the first phase relies are quite certain. Utilities have adequate experience with CC to accurately project cost and time requirements. The 10 years assumed for phase 1 allow the utility to test networked breaker systems and choose one for implementation in phase 2. The two sets of guidelines encourage the utilities to identify projects that combine two or more mitigation methods. That is good practice.

A third important take-away is that if a utility states that it can complete the undergrounding of all circuit miles in high fire-hazard areas in a certain time, that <u>completion time must be guaranteed or not used.</u> The only way I can imagine that will prevent gaming the calculations by a utility would be to require it to refund monies they were allowed to raise from customers, if it is later found that it did not complete their plan on time. Easier perhaps would be to simply disallow plan costs that extend beyond the date originally set for plan completion.

<u>We need to include all costs and so the comparison must run out to the last year for the slowest alternative to mitigate all line-miles. This is the only way to count project effects on the frequency of large wildfires completely. Only the (c)(6) analysis can do this.</u>

<u>For long-range impacts, the (c)(6) cost-benefit analysis for 50 years or more generally will be a crucial check on the short-term (c)(4) 10-year analysis based on risk modeling. The cost-benefit approach uses the utility data on projected wildfires more directly and so is easier to understand and verify. Both agencies should require that both types of analysis be done. The rankings of Alternative projects for cost-effectiveness should be the same in both analyses.</u>

<u>B. Spatial Lumping of Projects</u>

The OEIS draft guidelines recommend that planned projects and Alternative projects be lumped together so as to be adjacent. <u>This constraint is not needed</u> and will often require the inclusion of lower-risk circuits or segments and so reduce Plan risk reduction effectiveness, for any given number of circuits (projects). This lumping recommendation will also reduce the number of highest-priority projects that can be completed in the first 10 years, for any given number of circuits.

C. Metrics

In the comments submitted to the CPUC on their SPD Staff Proposal (9/13/23) and to OEIS on their SB 884 Guidelines (10/16/23) some experts would like OEIS to also evaluate costs using the RSE and B/C metrics, to fully evaluate project prioritization. Doing this would also make the review procedures for SB 884 UG Plans, WMP updates, and GRC proposals more similar in critical ways and therefore easier to follow for interest groups and citizens. This is a good idea, as it will improve methods and make it easier for interest groups and citizens to participate. This process will also focus agency attention on the (c)(6) long-term analysis, where the most-important impacts will be revealed directly, not buried in project risk coefficients, which are hard to understand.

Thank you for considering these comments.

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My Qualifications

I taught and did research on environmental planning issues at UC Davis, 1971-2005. Since then, I have been a local planning commissioner and a State conservancy board member. I have also done applied research for community groups.

Some of my UCD research was funded by the CEC, Caltrans, and other State agencies to perform statewide economic modeling, regional transportation modeling, GIS modeling systems, regional urban growth models, and various other kinds of public policy evaluation. My work included improving multi-objective evaluation methods used in water resources decision making. I have published research papers on benefit-cost methods, environmental assessment tools, and environmental justice. I helped the USEPA write the metro transport planning rule under the Clean Air Act.

In general, I advocate the use of public policy evaluation methods, which include cost-benefit analysis, focus on long-range and large impacts, include qualitative impacts, and pay attention to equity effects on different income groups.

Robert A. Johnston, Professor Emeritus
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December 27, 2023
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**COMMENTS OF THE UTILITY REFORM NETWORK (TURN)**
**ON DRAFT RESOLUTION SPD-15 IMPLEMENTING SB 884**

December 28, 2023

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**Comments of The Utility Reform Network (TURN)**
**On Draft Resolution SPD-15 Implementing SB 884**

The Utility Reform Network (TURN) submits these comments on Draft Resolution SPD-15 (Draft SPD-15) pursuant to the November 9, 2023 cover letter accompanying Draft SPD-15.

## 1. Introduction and Summary

TURN appreciates the CPUC's efforts to implement Senate Bill (SB) 884 in a way that is faithful to the complex structure and provisions of that legislation. However, two changes in Draft SPD-15 that deviate significantly from the original Staff proposal are contrary to the intent and goals of the statute and must be changed.

First, SPD-15 would allow what amounts to ***automatic approval*** of costs that, pursuant to the Phase 2 decision, have only been *conditionally* approved. It provides neither an opportunity for meaningful review by interested parties nor the statutorily required determination by the CPUC of whether the all-important conditions specified by the Commission pursuant to Section 8388.5(e)(1) have been satisfied.[1] Those conditions are the key mechanism prescribed by SB 884 to ensure that ratepayers are protected from paying unreasonable costs for undergrounding. Draft SPD-15 would negate SB 884's required means of ensuring that only just and reasonable costs are included in rates.

Second, Draft SPD-15 would effectively grant utilities a *blank check* to spend unlimited amounts in excess of the supposed annual caps on undergrounding expenditures, and then allow utilities to seek to include this overspending in rates. Inviting such overspending is contrary to the manifest intent of SB 884 that approval of undergrounding plans be conditioned on the achievement of cost efficiencies and reductions. Recent experience shows that, if utilities are given such a cost recovery opportunity, they will spend huge amounts above authorized forecasts – *PG&E spent $14 billion on wildfire mitigation in 2020-2022 compared to its authorized forecast of $4.7 billion* -- anticipating that the Commission will find it difficult to disallow rate recovery of any significant portion of funds that have already been spent. Rather than undermining the cost discipline that SB 884 requires by allowing unlimited overspending, the Commission needs to re-establish control over cost recovery for utility expenditures, as Commissioner Houck has recently urged, and require utilities to live within a budget for their undergrounding programs.

These comments recommend changes to Draft SPD-15 patterned on the prior Staff proposal – with improvements. The upshot of TURN's recommended changes is to require the utilities to: (1) demonstrate, based on a meaningful record, that they have complied with the conditions established in the Phase 2 decision to ensure that only just and reasonable costs are eligible for recovery in rates; and (2) execute their approved undergrounding plans within annual budgets --

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[1] All statutory references are to the California Public Utilities Code, unless otherwise indicated.

namely the annual CPUC-approved cost caps -- just like households, other businesses, and governments must do with their expenditures. If a utility believes that significant changes that were unforeseeable when the Phase 2 decision was issued require an increase in the cost caps at some point in the 10-year program, the utility can submit a petition to modify the Phase 2 decision to seek a prospective increase in the annual caps. In this way, the CPUC can determine whether changes to the cost caps are warranted in future years, while avoiding the cost control disincentives that come from issuing a blank check.

TURN is also concerned with the process the CPUC is using to implement SB 884. The CPUC is requiring parties to submit what appear to be final comments without knowing how the Office of Energy Infrastructure Safety (Energy Safety) intends to implement *its* responsibilities under SB 884. As a result, parties do not know what, if any, requirements Energy Safety will impose regarding such important matters identified in SB 884 as the cost effectiveness of the proposed undergrounding projects compared to alternatives and whether the utility plans sufficiently prioritize the proposed work in the highest risk areas. Thus, until Energy Safety produces its final proposal, TURN cannot comment on whether additional changes are needed to SPD-15 to ensure that utilities are required to meet these two requirements, which are essential to satisfying the just and reasonable standard. The solution to this flawed process is for the Commission, consistent with its statutory responsibility to establish the SB 884 program -- *to release for comment the full <u>combined</u> proposal of the CPUC and Energy Safety* before either agency's proposal is implemented.

Other changes and clarifications to Draft SPD-15 are needed:

- To the extent that utilities rely on claims of avoided or reduced costs of other wildfire mitigations, such as vegetation management, to justify their undergrounding plans, they must be held accountable for such claims. SPD-15 should require the Phase 2 application to demonstrate the mechanism by which the utility will ensure that ratepayers receive the claimed savings. (Section 5 of these Comments).
- The Commission should clarify that the utility's Phase 2 applications must include the estimated revenue requirement and bill impacts of the proposed undergrounding plan for each year of the several decades that rates would be increased, not just for the 10-year duration of the plan. (Section 6).
- To avoid a poor use of Commission and party resources, utilities should not be allowed to use the SB 884 process as a means to re-litigate undergrounding budgets that have already been thoroughly addressed and resolved in general rate cases. (Section 7).

Appendix A to these comments includes a mark-up of Attachment 1 to Draft SPD-15 to show TURN's recommended changes.[2]

## 2. Draft SPD-15 Must Be Revised to Require Utilities to Demonstrate Compliance with All Prescribed Conditions Before Cost Recovery May Be Allowed

Draft SPD-15 affords utilities two opportunities to add costs of undergrounding projects to rates if a utility's Phase 2 application for conditional approval of plan costs is approved: (1) via a one-way balancing account to recover costs up to annual capped amounts; and (2) via a Phase 3 cost recovery application to recover costs above the caps that are recorded to a memorandum account. This section addresses the first cost recovery opportunity. (Section 3 will discuss the Phase 3 opportunity to recover overspending.)

As explained below, even though Draft SPD-15 correctly recognizes that conditions on cost recovery are required by SB 884, Draft SPD-15 does not prescribe any opportunity for interested parties to conduct analysis and provide comment to the CPUC regarding whether the conditions have been satisfied. By allowing the utilities to self-determine their compliance with the conditions, Draft SPD-15 effectively allows *automatic* rate recovery for expenditures up to the cap, without a Commission determination that the recorded costs meet the just and reasonable requirement of Section 8388.5(e)(6). This aspect of Draft SPD-15 must be corrected to require utilities to seek recovery of recorded expenditures up to the capped amounts via an expedited application process that provides a meaningful record for the Commission to determine whether the conditions have been met and the costs satisfy the just and reasonable standard.

### 2.1. Draft SPD-15 Would Allow What Amounts to Automatic Cost Recovery Without Any Meaningful Opportunity to Assess Whether the Utility Has Complied with the Specified Conditions

Draft SPD-15[3] correctly recognizes that what it terms the Phase 2 application (following "Phase 1" approval of a plan by Energy Safety) may only request *conditional* approval of the plan's costs, in accordance with SB 884.[4] Consistent with the statute, Draft SPD-15 specifies certain detailed conditions that must be satisfied. These include a showing that the "average recorded CBR [Cost-Benefit Ratio]" equals or exceeds the "threshold CBR value" for that year, and that the average recorded unit cost does not exceed the approved unit cost target for that year. Additional

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[2] As noted, TURN's mark-up does not include additional changes that may be needed to ensure satisfaction of the just and reasonable requirement that depend on Energy Safety's rules for implementing SB 884.

[3] Draft SPD-15, p. 2.

[4] Section 8388.5(e)(1) (application to the CPUC may request "review and *conditional* approval of the plan's costs") (emphasis added).

conditions may be specified in the Phase 2 decision.[5] As discussed further below, whether the conditions have been satisfied will rely on utility factual showings and data inputs that, at least in some instances, will be controversial and that, in all instances, will need to be carefully reviewed for correctness and accuracy.

SB 884 is unequivocal that, before the CPUC may authorize rate recovery, it must ***determine*** that the recorded costs are just and reasonable.[6] Because the Phase 2 decision, consistent with SB 884, can only grant *conditional* approval of a utility application, the requisite just and reasonable determination requires the Commission to find, at a minimum, that the utility's requested recovery of recorded costs satisfies all of the prescribed conditions.

However, Draft SPD-15 does not identify or describe any process for the Commission to ensure compliance with all conditions and to make the required determination that costs are just and reasonable before they may be included in rates. Instead, Draft SPD-15 merely states that "[c]osts recorded in the one-way balancing account shall meet [all specified] conditions . . .."[7] SPD is silent on the prescribed process for: 1) the utility to make the required showing that conditions have been met; 2) interested parties to analyze and respond to the utility's showing; and 3) a Commission decision on a utility showing. The implication of Draft SPD-15 is that *the utility will be allowed to decide for itself* whether its recorded costs satisfy the Phase 2 decision conditions and will be able to automatically include in rates any amounts that the utility believes pass muster.

Allowing the utilities the autonomy to decide whether the conditions have been satisfied and the recorded costs are just and reasonable is plainly contrary to SB 884's requirement for a CPUC determination of these matters before cost recovery may be authorized. Letting a utility police itself with respect to compliance with the CPUC's conditions would thus violate the statutory requirement that *the CPUC* to determine that the recorded costs are just and reasonable before they are included in rates. It would also run contrary to the fundamental tenet of utility regulation that the commission, not the regulated entity, makes the final decision regarding whether costs are just and reasonable and warrant inclusion in rates.

In sum, Draft SPD-15 would allow automatic recovery of any recorded costs that the utility chooses to include in its one-way balancing account, without any determination by the commission that the recorded costs satisfy the Phase 2 decision conditions and the just and reasonable requirement. Such automatic recovery directly conflicts with Section 8388.5(e)(6). Whether or not the recorded costs are booked to a one-way balancing account or a memorandum account, the Commission must make clear that recovery of any costs booked to the account is contingent on a CPUC determination that the costs meet all prescribed conditions. To avoid legal error, Draft SPD-

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[5] Draft SPD-15, Attachment (Att.) 1, p. 10.

[6] Section 8388.5(e)(6) ("The commission . . . shall authorize recovery of recorded costs that are determined to be just and reasonable.") Only the CPUC (*i.e.*, not the utilities) can determine that the costs are just and reasonable for inclusion in rates.

[7] Draft SPD-15, p. 5.

15 must be revised to prescribe a process that provides the necessary record for the CPUC to make the statutorily required determination, as discussed in the following section.

### 2.2. The Commission Should Use an Expedited Application Process to Ensure Sufficient Review of Compliance with Conditions

To make the determination required by Section 8388.5(e)(6), the Commission needs to adopt a process that ensures an adequate record for deciding whether the Phase 2 conditions have been satisfied. As described above, the current proposal lacks any process. In the original September 2023 Staff Proposal, Staff recommended using a Tier 3 advice letter for this purpose.[8] TURN urges, instead, that the Commission use an expedited application process, akin to the catastrophic wildfire application process described in Section 1701.8.[9]

Under such an expedited application process, the Commission in its Phase 2 conditional approval decision could prescribe procedural rules specific to this unique situation – review of costs that have been conditionally approved -- that allow for expedited review and an expedited determination of the recorded costs that are entitled to rate recovery. To truly expedite such a proceeding, the Commission would need to specify detailed data submission requirements that the utility must meet in its cost recovery application, based on the conditions the recorded costs must satisfy. In addition, if a utility were to claim confidentiality for any of the information, it should be required to include with its application a model nondisclosure agreement to facilitate the parties' prompt receipt of such data. Assuming such comprehensive data submission requirements are specified by the CPUC and fulfilled in the utility's application, the Commission could require expedited protests and an expedited prehearing conference to enable the issuance of a scoping ruling within as few as 30 days of the application's filing. While the specific schedule would be adopted in each expedited application proceeding, TURN believes that a decision based on a reasonable record could be adopted in as few as eight months or less, barring unforeseen issues complicating a cost recovery request.

An advice letter process would *not* provide the Commission the record it needs to make the just and reasonable determination that Section 8388.5(e)(6) requires. To assess compliance with the conditions, the parties and Commission will need to review and analyze significant volumes of information regarding recorded costs, unit costs, and Cost Benefit Ratio (CBR) calculations. CBRs are particularly complex and judgment-laden calculations, which depend on inputs that have proven controversial in the past, raising issues such as:

- Whether the utility is using reasonable mitigation effectiveness values, which are often based on utility judgment;

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[8] Safety Policy Division, *Staff Proposal for SB 884 Program*, September 2023, p. 9 (September 2023 Staff Proposal).

[9] TURN's September 27, 2023 Informal Comments (pp. 7-8) proposed a traditional application process for this purpose. Here, TURN is recommending an expedited application process. To be clear, TURN is not saying that the Section 1701.8 procedures would or should apply here, only that they could be used as a guideline for an expedited process.

- Whether the utility input data is sufficiently granular or overly aggregated;
- Whether the utility is using a reasonable statistical value of life for safety consequence calculations; and
- Whether the utility is using reasonable discount rates for benefits and costs in the CBR calculation.

In addition, because cost-effectiveness and risk analysis is always evolving, a utility's assumptions, methodology, and inputs for calculating CBRs will likewise evolve over time and will need careful scrutiny for each year of recorded costs proposed for cost recovery.

Even less complex cost information that the utility will need to present, related to compliance with cost caps and unit cost targets, is likely to raise controversial issues, such as: whether only reasonable cost elements directly related to the undergrounding work are included in the costs (e.g., what costs are included in overhead and are those costs reasonable?); and whether the costs are consistently and correctly recorded to the right year based on project timing (a utility could manipulate the timing of recording costs in order to game the cost caps). An illustration of the judgment determinations that can arise with cost calculations is the extensive debate in the recently decided PG&E GRC regarding the appropriate cost elements to include in PG&E's covered conductor program.[10] The proposed decision (PD) and final decision differed on this question by 58%, with the PD recommending an $800,000 unit cost and the final decision adopting a unit cost of $1.261 million. Controversies such as these require the CPUC to make the final determination of what is reasonable, based on an adequate record built by the parties.

An advice letter submission does not provide sufficient process for the required determination of whether all conditions have been satisfied. General Order (GO) 96-B states that the advice letter process is not appropriate for matters that are expected to be controversial.[11] As discussed above, there is every reason to expect significant controversy regarding whether all proposed costs satisfy the Phase 2 conditions. In addition, GO 96-B states that "a matter that requires an evidentiary hearing may be considered only in a formal proceeding."[12] The CPUC's required determination of compliance with conditions will need to rest on findings related to purely factual matters upon which, at least for some issues, there is likely to be significant dispute, warranting an evidentiary hearing to test the veracity of parties' factual assertions. While, for its part, TURN would work to avoid the need for evidentiary hearings as much as possible, the processes adopted here must contemplate the possibility that, in some instances, an expedited evidentiary hearing process may be needed.

In addition, an advice letter process (including Tier 3) does not provide interested parties a meaningful opportunity to review and analyze utility cost recovery requests and reach well-

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[10] D.23-11-069, pp. 259-262, devoting four full pages to the reasonable unit cost for the covered conductor program, and finding that the elements included in the adopted $1.261 million cost should be broader than the elements in the proposed decision's unit cost of $800,000 per mile.

[11] GO 96-B, Section 5.1.

[12] *Id.*

informed conclusions about the extent to which the costs warrant inclusion in rates. Advice letter rules allow interested persons only 20 days to submit comments, and do not contemplate discovery. Twenty days is insufficient for any intervenor to complete the minimally required tasks of reviewing all supplied information and detailed Excel workpapers, propounding discovery, analyzing the information and data request responses, and preparing a responsive pleading.

Notably two recent State Auditor Reports have found the CPUC's review of utility wildfire cost recovery requests inadequate, even when applications have been required.[13] In response, the CPUC's comments asserted that a key "safeguard" in such cost recovery proceedings is "the evidentiary hearing litigation that serves as a critical platform . . . to scrutinize, test, and challenge the veracity and prudence of utilities' costs."[14] As the CPUC itself stated, the evidentiary hearing process, in which intervenors have the main responsibility for scrutinizing the utility costs, is a key component of this safeguard. This process requires a formal application proceeding for the review of conditionally approved costs, not an advice letter. Further, this claimed safeguard is not meaningful unless intervenors are afforded adequate time and discovery rights to scrutinize, test and challenge the veracity of the utility costs. TURN's proposed expedited application balances the need for efficiency with the time required for adequate scrutiny of utility costs.

In sum, to ensure a legally adequate process for the Commission's required determination that recorded costs are just and reasonable before they may be included in rates, Draft SPD-15 must be revised to provide that recovery of costs up to the Phase 2 decision cost caps shall be requested in an expedited application process, with the specific procedures and schedule to be determined in each individual request.[15] As shown in TURN's redline of the revised Staff Proposal accompanying Draft SPD-15, these expedited applications for cost recovery would be submitted in Phase 3 of the program.[16]

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[13] Report 2021-117 of the California State Auditor: *Electrical System Safety – California's Oversight of the Efforts by Investor-Owned Utilities to Mitigate the Risk of Wildfires Needs Improvement,* March 2022 (March 2022 State Auditor Report), pp. 51-52; Report 2022-115 of the California State Auditor: *Electricity and Natural Gas Rates: The California Public Utilities Commission and Cal Advocates Can Better Ensure that Rate Increases Are Necessary,* August 2023 (August 2023 State Auditor Report), pp. 39-43 .

[14] March 2022 State Auditor Report, p. 65 (CPUC Response to Audit findings).

[15] TURN is agnostic regarding whether the costs up to the capped amount are booked to a balancing or memorandum account (in Appendix A, TURN labels it a one-way balancing account), as long as, consistent with Section 8388.5(e)(6), they are not recovered in rates until the Commission has determined, in an expedited application proceeding, that the utility has satisfied all applicable condition.

[16] As discussed in Section 3.4 below, these expedited Phase 3 applications for recovery of costs up to the annual cost caps would replace the Phase 3 applications contemplated by Draft SPD-15 that would allow utilities to request recovery of cost overruns above the cost caps.

## 3. Draft SPD-15 Must Be Revised to Promote the Cost Efficiencies that SB 884 Requires By Removing the Opportunity to Recover Cost Overruns

Draft SPD-15 would allow utilities to record to a memorandum account any costs of executing the approved plan that exceed the annual cost caps established in the Phase 2 decision. The utility could then submit Phase 3 applications to recover these cost overruns in rates.[17] These provisions are a major departure from the original staff proposal, which did not have a Phase 3 process for recovering cost overruns, and which instead recommended adverse consequences if a utility exceeded the cost caps or other conditions of approval.[18]

TURN vehemently opposes embedding in SPD-15 what amounts to an invitation to exceed the cost caps determined in the Phase 2 decisions. As discussed below, enabling cost overruns for undergrounding, the most costly wildfire mitigation, is contrary to SB 884 provisions that require the utility to achieve ongoing reductions in undergrounding costs. It is also contrary to long-established ratemaking policies that set cost targets based on forecasts in order to encourage cost discipline. Draft SPD-15 promotes a one-sided, utility-centric notion of regulatory certainty without giving sufficient weight to *ratepayers'* need for certainty that their bill increases will be manageable and that they will not be penalized with unsustainable rate hikes if they make the transition from fossil fuels to electricity for transportation, cooking and space heating. In short, the Commission should require utilities to live within a budget and remove from SPD-15 the Phase 3 cost recovery opportunity, which amounts to a blank check for cost overruns. The CPUC's established petition for modification process affords utilities the right balance of protection from unforeseen developments that may warrant changes to the Phase 2 cost caps.

### 3.1. Inviting Recovery of Cost Overruns Is Contrary to SB 884

Nothing in SB 884 requires providing the utilities an opportunity to recover costs that do not satisfy the Commission's cost recovery conditions. In fact, the statute requires the Commission to ensure that customers benefit from reductions and efficiencies in undergrounding costs.

SB 884 makes clear that achieving efficiencies and reductions in undergrounding costs must be a key condition of the CPUC's cost approval process. Section 8388.5(e)(6) shows that the Legislature was highly focused on cost control by requiring that the utility's application for conditional approval of plan's costs address the following:

> (A) Any substantial improvements in . . . *reduction in costs* compared to other hardening and risk mitigation measures over the duration of the plan.
>
> (B) The *cost reductions, at a minimum, that result in feasible and attainable cost reductions* as compared to the large electrical corporation's historical undergrounding costs.

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[17] Draft SPD-15, p. 5.

[18] The original Staff proposal added a 10% contingency to the overall and unit cost caps. Below, TURN recommends instead that unforeseen circumstances be addressed through the Commission's established petition for modification process.

(C) How the cost targets are expected to *decline over time* due to *cost efficiencies and economies of scale*.

(D) A strategy for *achieving cost reductions* over time.[19]

The Legislature's emphasis on the achievement of cost reductions is thus reflected in its specification of *four separate requirements* for the utility to achieve cost reductions – both as compared to alternative mitigations and historical undergrounding costs, and as a demonstration that utilities will deliver on their claims of realizing cost efficiencies with the benefit of time and economies of scale.

Allowing utilities to seek recovery of recorded cost overruns defeats the purpose of these requirements. SB 884 clearly intends for the Commission to require utilities to achieve more efficient implementation, *i.e.,* declining unit cost caps over time. Utility incentives to actually achieve this statutory requirement will be dulled, if not eviscerated, if utilities know that will have the opportunity to recover cost overruns in later applications. As discussed in the next section, the experience with the wildfire mitigation memorandum accounts permitted under AB 1054 shows that, no matter how much the Commission emphasizes that costs recorded in memorandum costs must satisfy the just and reasonable requirement, utilities do not view such admonitions as a deterrent to spending huge amounts above authorized forecasts. SB 884 will not achieve its clear legislative intent unless utilities know that cost caps designed to deliver cost reductions and cost efficiencies are meaningful and will be enforced.

### 3.2. History Shows that, When Utilities Are Allowed to Seek Cost Recovery of Wildfire Mitigation Spending Above Authorized Forecasts Recorded to Memorandum Accounts, the Commission Loses Its Ability to Control Utility Spending and the Growth in Ratepayer Bills

The Commission has had several years of recent experience with a ratemaking model, pursuant to AB 1054, that allows utilities to record costs in excess of authorized general rate case (GRC) forecasts to memorandum accounts, and then seek recovery of those costs.[20] Despite admonitions in the statute and Commission decisions that only just and reasonable costs will be allowed to be included in rates and that unreasonable costs will be disallowed, the utilities have engaged in wildfire mitigation spending that dwarfs the forecast amounts authorized in their GRCs.

For example, PG&E's 2020 GRC decision authorized forecast costs for wildfire mitigation in 2020-2022 of \$4.7 billion.[21] During that period, PG&E *actually* spent \$14.3 billion.[22] Of that amount, it is reasonable to assume that at least \$11.4 million relates to CPUC-jurisdictional

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[19] Section 8388.5(e)(1) (emphasis added)

[20] Section 8386.4(a) and (b).

[21] *PG&E's Responses to ALJ's Ruling in A.21-09-008, A.22-12-009 and A.23-06-008*, October 27, 2023, p. 9, Tables 2 and 3.

[22] PG&E's 2023-2025 Wildfire Mitigation Plan (R3), p. 73.

activities.[23] It is therefore evident that, in 2020-2022, PG&E overspent its GRC authorized wildfire mitigation funding by well over 100%. This excess spending has already resulted in PG&E applications and advice letters seeking to recover an additional $5.2 billion in rates, a significant portion of which is still pending authorization for rate recovery.[24]

The lesson is that utilities show no reluctance to incur costs above authorized forecast levels if they can be booked to a memorandum account for future potential recovery. Utilities are clearly expecting that the Commission will find it difficult to disallow a significant portion of costs once they have been spent.

The result of inviting such overspending of authorized forecasts is that utilities do not feel constrained to live within a CPUC-prescribed budget, and the Commission loses control over the extent to which rates and bills are increasing. As Commissioner Houck expressed in her November 16, 2023 voting meeting remarks regarding the test year 2023 PG&E GRC decision:

> I am increasingly concerned that utility risk and the cost of minimizing this risk is being borne disproportionately by ratepayers. This is particularly concerning with the *growing number of memorandum and balancing accounts that we are asked to authorize*. Sheltering utilities from risk results in those risks being shifted and borne by ratepayers. And, as we see in this case, the rates that we are asking ratepayers to pay are increasing at a rate that *will become unaffordable in the very near future <u>if we don't find mechanisms to control costs</u>*.[25]

As Commissioner Houck observed, the proliferation of balancing and memorandum accounts threatens to shift too much risk from utilities to ratepayers and to diminish the CPUC's control over the trajectory of rate increases. Under traditional forecast ratemaking, the adopted forecast serves as something of a cap on rate recovery; with memorandum accounts, the adopted forecast becomes more like the floor for purposes of setting the amount that may ultimately be recovered in rates. Adding a new memorandum account that would invite even more overspending – for the most expensive wildfire mitigation program – would be a step in exactly the wrong direction.

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[23] PG&E's WMP does not provide a cost figure specific to CPUC-jurisdictional activities. The $11.4 million figure in the text attributes 20% of the $14.3 billion total spending to FERC-jurisdictional activities, based on the fact that FERC-jurisdictional costs historically average about 20% of PG&E's total electric revenue requirement.

[24] To date, PG&E's 2020-2022 excess spending on wildfire mitigation activities has spawned the following applications, with the amounts of additional requested wildfire mitigation cost recovery above adopted forecasts shown in parentheses: A.21-09-008 ($858 million); A.22-12-009 ($1.046 billion); A.23-06-008 ($2.25 billion); and A.23-12-001 ($1.033 billion).

[25] Transcribed remarks of Commissioner Houck at the November 16, 2023 CPUC Voting Meeting, 2:49:47 to 2:49:20. Video available at: https://www.adminmonitor.com/ca/cpuc/voting_meeting/20231116/

### 3.3. Requiring Utilities to Live Within a Budget Is Reasonable and Promotes California's Policy Goals

To promote the cost reduction and efficiency mandates of SB 884 and the Commission's policy goals, the Commission should expect and require utilities to keep the cost of their undergrounding plans within the cost caps established in the Phase 2 decision. Competitive companies experience challenges managing costs all the time. It is reasonable to expect utilities to use their managerial acumen to do the same. By the time any SB 884 plan is approved, all utilities will have had significant experience deploying undergrounding projects as a wildfire mitigation. Indeed, allowing PG&E to gain such experience and achieve cost reductions was a reason why PG&E was authorized to install 1,230 underground miles in its recent GRC decision.[26] If and when any SB 884 applications are submitted to the CPUC (which is not likely to occur before mid-2025, after Energy Safety's nine-month process), utilities should be able to develop accurate forecasts of their maximum unit costs at the outset of the program and to forecast a trajectory of unit cost decreases that it expects to achieve over the life of the program. The best incentive for utilities to achieve the CPUC's adopted forecast is for the Commission to make clear that utilities should not count on being allowed an opportunity to recover cost overruns.

True cost caps also address Commissioner Houck's concern regarding the unreasonable shifting of risk from utilities to ratepayers. As noted, utilities are well-positioned to anticipate and manage risks in deploying an undergrounding program. If need be, they can make adjustments to their programs to keep their costs within the CPUC's established caps, thereby avoiding the risk of unrecoverable costs. For their part, ratepayers have a right to expect that utility spending be managed to prevent unpredictable and unsustainable bill increases. Households need and deserve that certainty regarding how much to budget for an essential service, especially in light of California's electrification policies that rely on customers switching from fossil fuels to electricity.

Draft SPD-15 asserts that there are significant uncertainties regarding undergrounding costs that will likely increase over a 10-year period.[27] For the reasons stated in the previous paragraphs, TURN believes this concern is overstated, given the significant deployment of undergrounding that will have occurred in California as of the 2025-2026 time frame. However, even if the uncertainties are significant and increasing, making ratepayers shoulder the risks associated with those uncertainties is the wrong answer. The best way to manage the long-term uncertainty associated with approving a 10-year plan is to rely on the Commission's well-established petition for modification process.[28] If a utility anticipates operational changes outside of its ability to manage that were not foreseeable at the time of its Phase 2 application, the utility can seek a modification to the targets and cost caps adopted in the Phase 2 decision. If approved, these changes would apply on a *prospective* basis. In this way, the Commission would avoid the disincentives to cost

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[26] D.23-11-069, p. 266.

[27] Draft SPD-15, p. 7.

[28] Rule 16.4 of the Commission's Rules of Practice and Procedure.

discipline that would result from allowing utilities to unilaterally overspend their cost targets and then pressure the Commission into providing rate recovery of recorded cost overruns.

### 3.4. Recommended Changes to Draft SPD-15

The Commission would achieve regulatory certainty benefitting both utilities and ratepayers by removing from Phase 3 the opportunity to request recovery of cost overruns.[29] Utilities would benefit from the certainty of gaining conditional approval of an undergrounding plan for an extraordinary 10-year period, knowing that, if they comply with the CPUC's conditions, they will be able to recover costs up to the annual cost cap amounts. And the Commission and ratepayers would have a measure of certainty regarding the trajectory of rate increases that would result from implementation of the conditionally approved plan. The revisions to Draft SPD-15 should note that, if a utility becomes aware of unforeseeable changes outside their control that warrant changes to the Phase 2 decision, a utility is free to submit a petition for modification of that decision.

As noted, the cost cap conditions specified in Draft SPD-15 must be enforced in order for the Commission to ensure that utilities achieve the cost reductions and efficiencies that SB 884 contemplates as conditions of approval of any undergrounding plan. The Commission should clarify how the cost caps will be enforced by restoring the "Consequences for Failure to Satisfy Conditions of Approval" that were specified in the original Staff proposal.[30] In addition, the Commission should make clear that a utility that gains the benefit of conditional approval of a 10-year undergrounding plan will have no other opportunity to recover undergrounding costs than what is described in SPD-15. Cost caps would serve little purpose if utilities believe they can evade those cost caps, for example by proposing additional undergrounding mileage in their WMPs and recording the associated costs in a Section 8386.4 memorandum account. SPD-15 should state that the Commission has no intention of approving any undergrounding costs above the capped amounts determined in a Phase 2 decision, except in accordance with changes to the cost caps established via a petition for modification.

## 4. The Commission Must Allow Comments on the *Combined* Proposal of Energy Safety and the CPUC

To date, the CPUC and Energy Safety have been developing their SB 884 implementation plans on entirely separate tracks. At this point, Energy Safety has held working group sessions but not issued any proposal for stakeholder comment.

Until both agencies have presented their complete proposals, the Commission should not consider these comments to be the final comment opportunity on the CPUC's implementation plan. Without seeing Energy Safety's proposal, interested persons do not know what requirements Energy Safety will impose in order to gain that agency's approval. In its participation before Energy Safety

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[29] As discussed in Section 2.2 above, the Phase 3 cost overrun applications contemplated in Draft SPD-15 would be replaced by expedited applications to recover costs up to the cost caps.

[30] September 2023 Staff Proposal, pp. 11-12.

and in its comments on the original CPUC Staff proposal, TURN has emphasized that SB 884 requires that, among other things: (1) utilities demonstrate that they are only proposing to underground where it is the most cost-effective grid hardening alternative;[31] and (2) that the utility is adequately prioritizing the deployment of undergrounding based on risk.[32] TURN hopes that Energy Safety will specify sufficient requirements to satisfy these aspects of the statute in its implementation provisions. However, if not, the CPUC must address these requirements in its implementation rules and conditions, as undergrounding costs would not otherwise satisfy the just and reasonable requirement for cost recovery.[33] It would not be reasonable to require ratepayers to pay for undergrounding projects that are less cost-effective than alternatives and that are not prioritized to the highest risk areas.[34]

To provide a meaningful opportunity to comment on the combined efforts of Energy Safety and the CPUC to implement SB 884, the Commission should allow stakeholders another comment round after both agencies have issued their "final" implementation proposals. SB 884 makes clear that "the commission" is ultimately responsible for establishing this program.[35] Accordingly, the Commission should solicit this final round of comments on the combined proposal and make the final determination regarding any changes that are required.

**5. The Commission Should Require the Utility's Phase 2 Application to Demonstrate that Ratepayers Will Fully Benefit from Any Claimed Cost Reductions**

Draft SPD-15 appropriately requires utilities to identify wildfire mitigation costs (*e.g.,* vegetation management) that will be reduced or avoided as a result of the proposed undergrounding

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[31] Section 8388.5(c)(2) requires the utility's plan to prioritize projects based on "cost efficiency;" Section 8388.5(c)(4) requires the plan to provide a comparison of undergrounding with aboveground hardening for each project, comparing, among other things, risk reduction and cost; Section 8388.5(e)(1)(A) requires the plan submitted to the CPUC to show any improvements in risk reduction and cost of undergrounding compared to alternative mitigations.

[32] Section 8388.5(c)(2) requires the utility's plan to prioritize undergrounding projects "based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits." Subsections (c)(3) and (c)(4) also refer to "prioritized undergrounding projects."

[33] Section 8388.5(e)(6). In addition, as noted, Section 8388.5(e)(1)(A) specifically requires the plan submitted to the CPUC to show improvements in risk reduction and cost of undergrounding compared to alternative mitigations.

[34] TURN's September 27, 2023 comments on the original staff proposal (pp. 2-4 and redline attached thereto) contained detailed recommendations on language that would be necessary for the CPUC to include if Energy Safety does not adequately address the cost-effectiveness and risk prioritization requirements.

[35] Section 8388.5(a) provides: "The commission shall establish an expedited utility distribution undergrounding program . . .."

plan.[36] However, Draft SPD-15 does not require utilities to propose a mechanism to ensure that ratepayers will receive the benefits of such claimed cost savings. Without such a mechanism to hold utilities accountable, these utility assertions amount to empty rhetoric that is unenforceable.

In fact, Draft SPD-15 moves in the wrong direction on this point, by removing language in the original Staff proposal that would have required the utility to provide "the proposed disposition of the savings."[37] This language should be restored and augmented by requiring the Phase 2 application to include a methodology by which the CPUC can ensure that the claimed cost savings will be reflected in rates.

**6. The Commission Should Require the Utility's Phase 2 Application to Estimate the Full Revenue Requirement and Bill Impacts for Each Year that the Plan's Undergrounding Costs Will Affect Rates**

Draft SPD-15 would require the utility's Phase 2 application to include the "proposed annual revenue requirements and proposed ratepayer impacts for each year of the 10-year Application period that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs. The intent of this requirement appears to be to require such disclosure for each year that plan costs would affect rates. However, the reference to the "10-year application period" creates ambiguity and could give rise to utility arguments that only 10 years of rate and bill impacts are required, which would be an unfortunate and unnecessary result.

Undergrounding costs, which are primarily (if not exclusively) capital expenditures, will have a long-term impact on customer rates and bills not just for 10 years, but for the several decades that undergrounding costs are in rate base. The CPUC should be aware of that full impact before conditionally approving any plan. To avoid any ambiguity, SPD-15 should delete the confusing reference to the 10-year application period and require the utility's best estimate of the "proposed annual revenue requirements and proposed ratepayer impacts for each year that the [utility] proposes will be necessary for rate recovery of the plan's costs."[38]

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[36] Draft SPD-15, Attachment 1, p. 7, Item 4.

[37] September 2023 Staff Proposal, p. 6, Item 6.

[38] To estimate long-term revenue requirement and bill impacts, the utility will need to make assumptions regarding matters including its future authorized cost of capital and depreciation parameters. The utility should be required to provide the assumptions on which its revenue requirement and bill impact estimates are based.

## 7. The Commission Should Not Let the SB 884 Process Serve as an Opportunity for Utilities to Re-Litigate Prior CPUC Decisions Regarding the Appropriate Scope and Cost of Undergrounding

Draft SPD-15 includes an asymmetric provision that would allow the utility to re-litigate undergrounding targets and cost forecasts that were previously disallowed by the CPUC.[39] Nothing in SB 884 requires such an opportunity. In fact, SB 884 directs the CPUC to consider not revising such previous determinations.[40] Undergrounding proposals are being heavily litigated in the current round of GRCs,[41] as was evident in PG&E's test year 2023 GRC decision.[42] It would be a poor use of scarce Commission and party resources to re-litigate those settled issues. Moreover, this aspect of Draft SPD-15 is one-sided in favor of the utilities, in that it does not indicate that other parties are also free to re-litigate those determinations in the Phase 2 application proceeding.

To fairly implement the statute and to avoid undue demands on CPUC and party resources, the Commission should delete the provision allowing the utility to re-litigate the CPUC's prior undergrounding determinations. If the Commission nevertheless wishes to invite utilities to engage in such re-litigation, then fairness dictates that other parties be given the same opportunity to re-litigate prior approved undergrounding targets and costs in the course of the Phase 2 conditional approval proceeding.

## 8. Conclusion

For the reasons set forth above, Draft SPD-15 should be revised as described in these comments and in Appendix A. In addition, the Commission should release for comment the full <u>combined</u> proposal of the CPUC and Energy Safety before either agency's proposal is implemented.

Dated: December 28, 2023

Prepared by:

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**THE UTILITY REFORM NETWORK**

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[39] Draft SPD-15, Attachment 1, p. 7, Application Requirements, Item 2(c).

[40] PU Code Section 8388.5(e)(3).

[41] The current round of GRCs refers to PG&E's test year 2023 GRC, SDG&E's test year 2024 GRC, and SCE's test year 2025 GRC.

[42] The discussion and determination of PG&E's approved system hardening plan consumes 54 pages of D.23-11-069.

## Appendix A

## TURN Redline of Recommended Changes to Appendix 1 of Draft SPD-15

California Public
Utilities Commission

# Staff Proposal for SB 884 Program

S A F E T Y P O L I C Y D I V I S I O N

November 2023

# Table of Contents

# Purpose:

This Staff Proposal, if adopted, will satisfy the Commission's statutory obligation, pursuant to Public Utilities Code Section 8388.5(a), to establish an expedited utility distribution undergrounding program consistent with Senate Bill No. 884[1] (SB 884). This Staff Proposal addresses the process and requirements for the Commission's review of any large electrical corporation's 10-year distribution infrastructure undergrounding Plan (as defined below) and its related costs.

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

# Background:

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

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

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

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

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

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[2] Energy Safety plans to separately issue guidelines detailing the requirements for submission and review of undergrounding Plans.

If the Plan is approved by Energy Safety and the Application requesting review and conditional approval of the Plan's costs is approved by the Commission, the large electrical corporation must file progress reports with the Commission and Energy Safety every six months, include ongoing work plans and progress in its annual wildfire mitigation plan submissions, hire an independent monitor (selected by Energy Safety) to review and assess its compliance with the Plan, apply for all available federal, state, and other non-ratepayer moneys throughout the duration of the approved Plan, and use those non-ratepayer moneys to reduce the Plan's costs to its ratepayers.

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

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

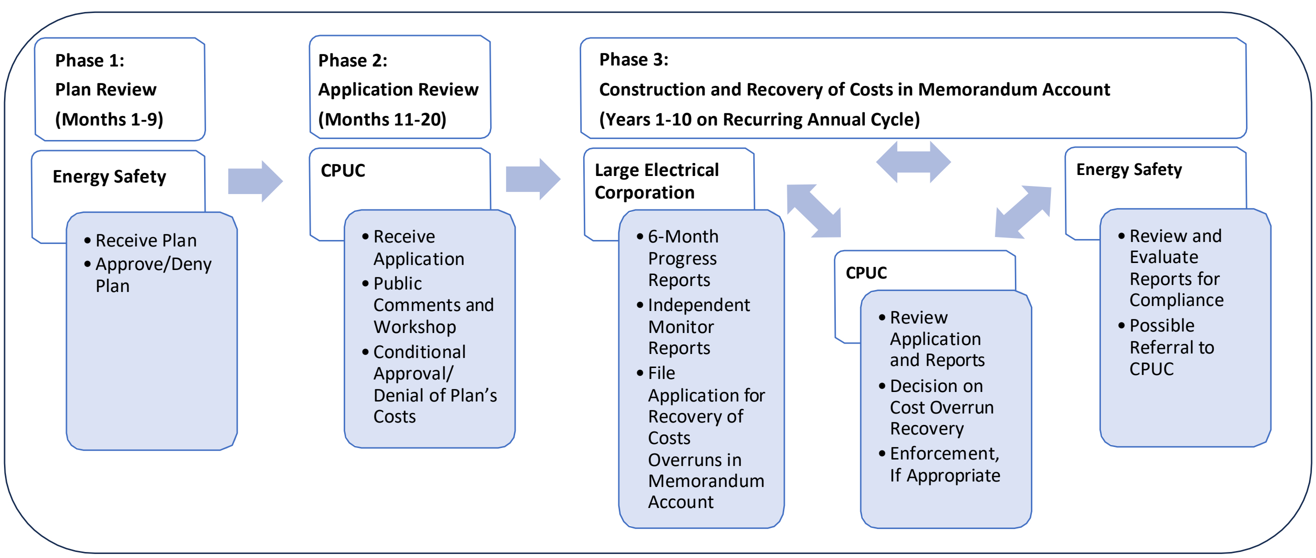


*Figure 1: SB 884 Plan, Application, Reporting, and Cost Recovery Timeline*

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

# SB 884 Program Process and Requirements:

Staff proposes the SB 884 Program be executed in up to three phases:

1) Phase 1: Energy Safety Plan review and approval/denial
2) Phase 2: Application submission and review for conditional approval.
3) Phase 3: Periodic ~~reasonableness~~ reviews of recorded costs~~-~~ to assess and make determinations regarding compliance with conditions for recovery in rates~~in the memorandum account described below~~.

If Energy Safety approves the large electrical corporation's Plan, Phase 2 will commence with the large electrical corporation's submission of an Application for Commission consideration and conclude with the Commission's disposition of such Application (i.e., conditional approval or denial). If conditionally approved in Phase 2, the large electrical corporation will record costs in ~~establish~~ a one-way balancing account ~~to recover costs~~[4] ~~from rates~~ up to an authorized target cap, as determined in the Phase 2 Decision~~, and a memorandum account to record any costs that are incurred in excess of the cap~~. The conditions will be those that the Commission finds are necessary to determine that the Plan's forecast costs are just and reasonable. The Commission may establish further conditions supported by the record of the Application's proceeding. Phase 2 will conclude upon the Commission's disposition of the Application.

If the Commission conditionally approves the large electrical corporation's Application, Phase 3 will commence upon the Commission's disposition of such Application. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting this Staff Proposal, the Commission's Phase 2 Decision, any other Commission decision on an Application submitted pursuant to the SB 884 program, and the large electrical corporation shall also report on its progress. During Phase 3, the Commission will ~~also~~ review ~~any~~ applications for expedited recovery of costs recorded in the memorandum account to determine whether such costs satisfy all conditions established in the Phase 2 decision and ~~were~~ are just and reasonable~~, and incremental to any other costs approved by the Commission~~. When making these determinations the conditions set forth in the Resolution adopting this Staff Proposal, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. Phase 3 will conclude with the Commission's disposition of the last cost recovery application associated with the memorandum account, or the final independent monitor report, whichever comes last.

Due to the SB 884 Program's expedited schedule, utilities ~~parties~~ shall respond to discovery requests within five (5) business days in either Phase of the SB 884 Program.

## Application Conditional Approval, Denial, or Modification & Resubmittal:

On or before nine months after the Application's filing date, the Commission shall review and conditionally approve or deny the Application. Before conditionally approving or denying the Application, the Commission or staff may require the large electrical corporation to (i) modify or (ii) modify and resubmit

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

the Application.[5] If the Commission or staff determines that minor corrections or clarifications are needed for the Application, then the Commission or staff may require the large electrical corporation to modify the Application and such minor corrections or clarifications shall be provided within five (5) business days. If the Commission or staff determines that the Application 1) omits material information required pursuant to the Commission Resolution adopting this Staff Proposal, 2) omits material information deemed necessary to process the Application within nine months, or 3) omits information otherwise required by SB 884, then the Commission or staff may require the large electrical corporation to modify and resubmit the Application, and such resubmission will restart the nine-month clock for the Commission's review.

## Pre-Submission Application Completeness Review:

Before submission of the Application, the large electrical corporation shall provide a copy of the intended Application to Commission's Safety Policy Division (SPD)[6] for a completeness review. The pre-submission process is a precursor to and separate from the Commission's Application review process. The intent of the completeness review will only be to identify any obvious omissions or errors and avoid unnecessary delays resulting from post-submittal modification of the Application for such omissions or errors, given the expedited schedule for review. SPD will conclude its completeness review within 10 business days of receipt and issue a report noting any deficiencies that should be corrected in the submitted Application. Accordingly, it is the large electrical corporation's responsibility to provide SPD with a copy of the intended Application with sufficient time to conduct the completeness review (i.e., 10 business days) while ensuring that the 60-day deadline for Application submission, following Energy Safety's approval of the Plan, is met pursuant to Public Utilities Code, Section 8388.5(e)(1). SPD's report is solely for completeness review; it is not a substantive review or disposition of the Application and it in no way limits the Commission's or staff's ability to require the large electrical corporation to otherwise modify or modify and resubmit the Application.

# Phase 2 – Application Submission and Review:

This Staff Proposal recognizes that Plans approved by Energy Safety will have been found to show that implementation of the Plan will substantially increase reliability and substantially reduce wildfire risk, as required in Public Utilities Code, Section 8388.5(d)(2) and to meet all other requirements established by Energy Safety or the CPUC. The Commission will then review such Plans and either conditionally approve or deny the costs, as presented in the subsequent Application.

## Application Submission Requirements:

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

**Submission Deadline:**

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

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

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

### Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting this Staff Proposal.[7] Each section of the Application shall indicate the person who sponsors the section and would serve as a witness if evidentiary hearings are required.

### Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,[8] as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties.

## Application Requirements:

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

All cost and Cost-Benefit Ratio (CBR)[9] data, required as described below, shall be supported by workpapers and Excel worksheets included with the Application submission.

The following is a list of required contents in Applications:

1) The Application shall present both capital and operating expense cost forecasts for each year of the 10-year Application period, consistent with the cost targets presented in the Plan approved by Energy Safety.
2) The Application shall clearly identify all undergrounding targets (*e.g.*, miles to underground together with their conversion rate[10]) and cost targets in the Plan that overlap with undergrounding targets and any and all related targets and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venues. Furthermore:

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

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

[9] CBR is calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3.

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

undergrounding corresponds to replacement of less than one mile of overhead assets.

a) Where undergrounding targets and cost targets in the Application overlap with undergrounding targets and cost forecasts approved in the most recent GRC or other cost recovery venue, such undergrounding targets and costs shall be clearly identified and associated costs will be excluded from consideration for recovery in the Application.

b) Where undergrounding targets and cost targets in the Application overlap with undergrounding targets and cost forecasts still under consideration in a GRC or other cost recovery venue, the Application shall specify which overlapping targets and costs are under consideration and identify the proceeding or advice letter in which the Commission is considering them. The Application shall propose in which venue the Commission should consider the overlapping costs. Both costs and the corresponding mileage must be paired and presented for consideration in a single venue.

c) ~~For undergrounding targets and cost forecasts which were previously disallowed by the Commission, the large electrical corporation shall identify the proceeding or advice letter in which the Commission made such determination, when that determination was made, and explain why a different conclusion is now appropriate.~~

d) The Application shall include a detailed description of the controls the large electrical corporation will implement to ensure that undergrounding costs related to execution of the Plan are incremental to any other costs approved by the Commission.

3) The Application shall include the utility's best estimate (and underlying assumptions) of the proposed annual revenue requirements and proposed ratepayer impacts for each year ~~of the 10-year Application period~~ that the large electrical corporation proposes will be necessary for rate recovery of the Application's forecasted annual costs.

4) The Application shall identify, for each year of the 10-year Application period, any forecast wildfire mitigation costs that will be reduced, deferred, or avoided because of implementing the proposed undergrounding Plan (e.g., vegetation management) (collectively "savings"), and how spending on such programs or areas of work will be affected, including any cost reductions, deferrals, or avoidances that are expected to continue beyond the 10-year Application period and the time period for which such cost reductions, deferrals, or avoidances are expected to continue beyond the 10-year period.[11]

a) 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 will be reflected in rates.

~~a)~~b) The Application shall distinguish between forecast costs already approved by the Commission for recovery, forecast costs for which the Commission previously denied a request for recovery, and forecast costs that have not yet been the subject of a request for recovery.

~~b)~~c) 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.

5) The Application shall include cost targets for each year of the 10-year Application period that, at a minimum, result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs.

a) Cost targets shall be provided for each projected year in the 10-year Plan.

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

b) Annual historical undergrounding unit costs shall be provided for the previous 10 years, with separate categories for Rule 20 projects, other undergrounding projects, and wildfire mitigation projects, as available.

c) Comparisons between the Plan's unit cost targets and historical undergrounding unit costs shall be provided using the average historical wildfire mitigation undergrounding costs for the previous three years (before the Plan's first year). The comparison shall include a statement of how the targeted cost reductions are feasible and attainable compared to historical costs.

6) The Application shall include an explanation of how the cost targets are expected to decline over time due to cost efficiencies and economies of scale.

7) The Application shall include a description of a strategy for achieving cost reductions over time per Public Utilities Code, Section 8388.5(e), which may include factors other than cost efficiencies or economies of scale such as, but not limited to, identifying, developing, and deploying new technologies.

8) The Application shall present the forecasted average Cost-Benefit Ratio (CBR) across all projects expected to be completed in each of the 10 years of the Application period, broken out by year and for the total Application period. Cost and Benefits must be calculated as defined in Commission Decision (D.)22-12-027[12] or its successor. The calculated annual and total benefits must relate to the mitigation of overhead line miles, not miles of undergrounding.[13] If projects will include secondary lines and service drops, those costs and benefits must be included.

9) The Application shall include the forecasted CBRs across all projects, broken out by year and for the total Application period, for each alternative wildfire mitigation hardening method~~s~~ considered, in place of undergrounding, including forecasted CBRs for combinations of non-undergrounding hardening mitigation measures. The calculated annual and total benefits must relate to the mitigation of overhead line miles, including any secondary lines and service drops, not miles of undergrounding.

10) The Application shall include a description of any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the Plan.

a) Substantial improvements in safety risks shall be substantiated using the above required benefits calculations by comparing undergrounding benefits to alternative hardening and risk mitigation measures, including combinations of alternative measures.

b) Reduction in costs shall be substantiated using the same cost calculations as required above by comparing undergrounding costs to alternative hardening and risk mitigation measures, including combinations of alternative measures.

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[12] CBR is calculated by dividing the dollar value of Mitigation Benefit by the Mitigation cost estimate. See D.22-12-027 Phase II Decision Adopting Modifications, Risk-Based Decision-Making Framework, Appendix A, p. A-3.

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

11) For each project included in the Plan and Application, the large electrical corporation shall provide, at a minimum, all data listed in Appendix 1 in tabular format.[14] This information shall be provided as both a Microsoft Excel file and searchable pdf file[15] to supplement the Application. The data listed in Appendix 1 is preliminary, and will be refined in consultation with Energy Safety, as it develops Plan requirements, to support uniformity where possible.
12) For each project included in the Plan and Application, the large electrical corporation shall provide GIS data for all project boundaries in a Geodatabase or other suitable format.[16]
    a) The GIS data shall include the entire circuit within which projects are planned and indicate the locations of which segments will be undergrounded.
    b) The GIS data shall identify the locations of circuit segments that will continue to support overhead transmission lines (if any) after distribution lines are undergrounded.
    c) The GIS data shall indicate the locations of poles which have lease agreements with communications companies, and which are jointly owned.
13) The Application shall include a list of all non-ratepayer moneys (i.e., third-party funding) the large electrical corporation has applied for and/or received to minimize the Plan's costs on ratepayers. At a minimum, for each potential source of third-party funding, the list shall include:
    a) The source of third-party funding;
    b) The date when third-party funds were requested;
    c) The amount of funding requested;
    d) The status of the request, including funding already received;
    e) Next steps, including timelines for processing of the funding request; and
    f) The amount of funding granted/authorized (if any).
14) The Application shall include a description of how any net tax benefits associated with the third-party funding will be disposed of to the benefit of ratepayers.
15) The Application shall include a statement affirming costs, tax benefits, and tax liabilities associated with federal funding sources used to fund projects included in the Plan are being tracked consistent with Resolution E-5254.[17]
16) The Application shall include an attestation that the large electrical corporation will continue to search and apply for third-party funding to reduce the cost of the Plan to ratepayers throughout the duration of the Plan.
17) The Application shall include a description of how the large electrical corporation plans to coordinate with communication companies to maximize benefits to California, including but not limited to:
    a) The ownership and use of existing utility poles where undergrounding projects are planned;

[14] The data requirements in Appendix 1 will be aligned with data submission requirements for the Plan, as developed by Energy Safety.

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

[16] Further details on GIS data submission requirements are expected to be issued by Energy Safety in the establishment of Plan guidelines. The GIS data submission requirements for Application submission are considered preliminary and will align with such GIS data requirements established by Energy Safety.

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

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

18) The Application shall include workforce development cost forecasts for each year of the plan.
19) The Application shall include a copy of the Plan approved by Energy Safety.

### Public Workshop & Comments:

The Commission will facilitate a public workshop for presentation of the Application and take public comment for at least 30 days in accordance with Public Utilities Code Section 8388.5(e)(4). Formal comments from the workshop will be solicited by a ruling in the proceeding, and a workshop report provided by the parties who participated in the workshop may be ordered. Additional procedures to ensure an adequate decision-making record will be determined in a Scoping Ruling of the Assigned Commissioner after a prehearing conference.

### Conditions for Approval of Plan Costs:

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

1) Total annual costs must not exceed a cap based on the approved cost target for that specific year.[18]
2) Third-party funding obtained, if any, shall be applied to reduce the established cost cap for the specific year in which the third-party funding is obtained, so that ratepayers receive the benefit. The large electrical corporation shall file an advice letter documenting which annual cost caps are reduced based on third-party funding received.
3) The average recorded CBR[19] for all projects completed in any given year must equal or exceed the threshold CBR value[20] for that year.
4) The average recorded unit cost in any given year must not exceed the approved unit cost target for that year. The unit costs shall be calculated per mile of undergrounding performed, rather than per mile of overhead replaced, to focus on reduction of construction costs.
5) Any further reasonable conditions supported by the record of the proceeding and adopted by the Commission in the Phase 2 Decision.

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

Phase 3 of the program will be initiated if the Commission conditionally approves a Phase 2 Application submitted by a large electrical corporation. During Phase 3, the large electrical corporation will execute its undergrounding Plan in accordance with the Resolution adopting this Staff Proposal, the Commission's

18 Any costs exceeding the cap shall be recorded in a memorandum account and are subject to review and approval as described in the Phase 3 section of this Staff Proposal.

19 The "recorded CBR" is the CBR calculated using recorded cost values, as opposed to cost forecasts.

20 The "threshold CBR value" will establish the minimum CBR that must be achieved for cost recovery.

Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to the SB 884 program, and the large electrical corporation shall also report on its progress.

~~If the large electrical corporation incurs costs in any given year that exceed the annual cost cap for the one-way balancing account established pursuant to a Phase 2 Decision, the large electrical corporation shall record such excess costs in the memorandum account established pursuant to the Phase 2 Decision.~~ The large electrical corporation may only seek recovery for costs recorded in the ~~memorandum~~ one-way balancing account by filing an application (hereafter, Phase 3 Application). The purpose of any Phase 3 Application will be to determine whether the ~~costs~~ Utility has satisfied all conditions prescribed in the Phase 2 decision and the costs are therefore ~~were prudently incurred, incremental to other funding granted to the large electrical corporation, and~~ just and reasonable. When making these determinations the conditions set forth in the Resolution adopting this Staff Proposal, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable. Phase 3 may extend over a series of Phase 3 Applications, as needed, to support cost recovery over the 10-year program period. The review period will be determined in the Commission's Phase 2 decision, provided that ~~N~~no more than one Phase 3 Application may be filed each year.

The elements of recorded costs must be consistent with the elements included in the costs presented in the Phase 2 Application, including but not limited to, program management, project execution, design, estimating, mapping, construction, internal labor, contracted labor, parts, tools, materials, overhead, and permitting.

The Phase 3 Application must include, at a minimum, all biannual progress reports and annual compliance reports submitted pursuant to this program, relevant information from wildfire mitigation plan filings and compliance reports, and the following project data presented in Table 1 for the requested recovery period.[21] The project data that supports the program recorded cost values requested for recovery shall be provided in tabular format in a sortable Excel spreadsheet.

*Table 1: Conditionally Approved Target and Actual Recorded Cost Data*

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

## Consequences for Failure to Satisfy Conditions of Approval

Detailed below are the consequences related to a large electrical corporation's failure to satisfy the Phase 2 Decision's conditions for approval that will be assessed in the periodic Phase 3 applications for authorization of rate recovery.

1) COST CAP. Recorded costs above the predetermined cap placed on annual cost targets

in the conditionally approved Application, adjusted for third-party funds received, will not be authorized for recovery.
2) THIRD-PARTY FUNDING. If non-ratepayer, third-party funding has not been deducted from the approved cost target, that portion of the costs will not be authorized for recovery.
3) COST BENEFIT RATIO. Cost recovery will be denied for as many projects as necessary to bring the recorded CBR average up to the approved target.
5) UNIT COSTS. Cost recovery will be denied for as many projects as necessary to bring the recorded annual unit cost average down to the approved target.

## Application Type:

Applications shall be submitted according to the Commission's Rules of Practice and Procedure and any other requirements set forth in the Commission Resolution adopting this Staff Proposal. The Commission shall expedite the resolution of the Phase 3 Applications to the extent possible consistent with the development of a meaningful record for the Commission's decision, including specifying an accelerated date for the submission of protests and responses, for the convening of a prehearing conference, and the issuance of a Scoping Ruling.

## Application Submission:

The Application shall be filed and served with the Commission's Docket Office, with a copy to the Commission's Chief Administrative Law Judge, the service list for the large electrical corporation's most recent general rate case (GRC), the SB 884 notification list linked here,8 as updated, SB884@cpuc.ca.gov, and any other service lists, as determined by the large electrical corporation, that will cause the Application to broadly reach interested parties.

## ~~Conditions for Approval of Recorded Costs in Memorandum Account:~~

~~To further protect ratepayers from unexpected and inefficient cost overruns:~~

1) ~~The Commission will closely scrutinize any Phase 3 Application to determine whether the costs recorded were prudently incurred, incremental to other funding granted to the large electrical corporation, and just and reasonable.~~

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

~~2) When making these determinations the conditions set forth in the Resolution adopting this Staff Proposal, the Commission's Phase 2 Decision, and any other Commission decision on an Application submitted pursuant to SB 884 should be considered in light of the fact that such costs must be just and reasonable.~~
~~3) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be approved unless and until the large electrical corporation has shown that is has applied all third-party funding previously received to reduce its relevant balancing account cost cap.~~
~~4) No costs recorded to the memorandum account established in the Commission's Phase 2 Decision shall be approved unless such costs are consistent with the approved Plan.~~

## Progress Reports:

Public Utilities Code Section 8388.5(f)(1) requires large electrical corporations with approved Plans and conditionally approved Applications to file progress reports every six months with both Energy Safety and the Commission. Because the progress reports are filed with multiple agencies and at the same time, Staff propose that Energy Safety and the Commission collaborate to develop a singular set of requirements for these reports. Aligning the requirements for these progress reports may eliminate any unnecessary duplication of effort and optimize efficiency of available resources. However, it is possible that each agency will require distinct information in the progress report. Staff understand that Energy Safety plans to detail its requirements in a forthcoming set of guidelines. Accordingly, without affecting the required progress report elements specified by Energy Safety, Staff propose that the 6-month progress reports shall include, but should not be limited to, the following:[22]

1) Total recorded costs to date;
2) Third-party funds received, with an explanation of how third-party funding was used to reduce the burden on ratepayers;
3) Average recorded CBR for completed projects;
4) Average recorded unit cost per mile of undergrounding for completed projects;
5) Miles of overhead replaced by undergrounding;
6) Miles of undergrounding completed;
7) GIS data showing location and status of each project (in Geodatabases or other suitable format);[23]
8) An updated list of all third-party funding the large electrical corporation has applied for, as specified in Application Requirements 13-15; and
9) Total and average avoided costs and workpapers showing calculation of avoided costs.

## Wildfire Mitigation Plan Integration:

Public Utilities Code Section 8388.5(f)(2) requires large electrical corporations to include ongoing work plans and progress relating to their undergrounding plans in annual wildfire mitigation plan filings. Staff

[22] Staff reserve the right to amend the below listed progress report requirements following consultation and coordination with Energy Safety.

[23] Data requirements to be aligned with those specified in Energy Safety guidelines.

understands that further guidance on incorporating this information into annual wildfire mitigation plan filings will be provided by Energy Safety.

### Compliance Reports:

Public Utilities Code Section 8388.5(f)(3) requires a large electrical corporation with an approved Plan and conditionally approved Application to hire an independent monitor selected by Energy Safety. The independent monitor must assess whether the large electrical corporation's progress on undergrounding work is consistent with the objectives identified in its approved Plan.[24] For each year the Plan is in effect, the independent monitor must annually produce a compliance report detailing its assessment by December 1.[25] The independent monitor's compliance report must also specify any failure, delays, or shortcomings of the large electrical corporation and provide recommendations for improvements to accomplish the objectives set forth in the approved Plan.[26]

## Changes to the Plan:

Any changes to the conditions of approval of the Plan in the Commission's Phase 2 decision must be requested by a petition for modification filed pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure.

The procedures for considering a large electrical corporation's request to change elements of its Plan that do not require a modification of the conditions of approval in the Phase 2 decision, including ~~cost forecasts,~~ modifications of the project list, and risk model changes, will be determined by the Commission in coordination with Energy Safety in a subsequent process.

## Penalties:

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

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

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

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

# Appendix 1: SB 884 Project List Data Requirements-Preliminary[27]

| Field Name | Field Description |
|---|---|
| **Order** | Unique Project Order Number. |
| **Category** | Work Category Type. Possible values:<br>• Base System Hardening<br>• Community Rebuild<br>• Fire Rebuild<br>• Targeted UG<br>• Other, see comment |
| **Category Comment** | Category type not listed in the options above. This field is required if Category is "Other, see comment". |
| **Program Identification Code** | A unique Internal Program Identification code associated with the project and consistent with codes used in GRC and WMP filings to allow for tracking across filings (e.g., Maintenance Activity Type Code, Business Planning Element, etc.). |
| **Status** | Possible Values:<br>• Scoping: Identifying the proposed route of undergrounding the electric distribution lines, which includes gathering base map data (i.e., Light Detection and Ranging (LiDAR) and survey data of the expected route) and identifying any long lead time dependencies (i.e., land acquisitions, environmental sensitivities and permits). Scoping includes breaking out planned circuit segments into smaller, more manageable projects. Scoping is the first step to providing visibility to the construction feasibility and possible execution timing.<br>• Designing/Estimating: Designing the specific project to determine trench location, connection points, equipment details, materials needed, and related details, such as circuitry and pull boxes. The design also provides information about the land rights needed and produces the drawings that are submitted |

[27] To be finalized in coordination with Energy Safety's SB 884 guidelines.

| Field Name | Field Description |
|---|---|
| | for permits. The project cost, including expected labor and materials, is calculated at this stage.<br>• <u>Permitting/Dependency:</u> During this stage the large electrical corporation may need to obtain land rights, environmental permits, construction contracts, encroachment permits from local counties, state and/or federal agencies, order long-lead materials, finalize construction cost estimates, and determine the construction schedule. The two longest lead dependencies often include obtaining land rights and environmental permits.<br>• <u>Ready for Construction:</u> Undergrounding project is ready for construction.<br>• <u>Construction:</u> Executing the undergrounding takes place in two phases: (1) civil construction and (2) electric construction. Project schedules may be significantly impacted during civil construction due to unanticipated weather, discovery of hard rock, and/or detection of unmarked existing utility infrastructure. Once civil construction is complete with conduit and boxes installed, then electric construction resources pull the cable through the conduit, splice segments together and re-connect the customers to the new underground system. Customer input regarding the timing of re-connection, material availability, weather, and other risks can impact the electric construction schedule as well. |
| **Division** | Division of the service territory in which the project will take place. |
| **Region** | Region of the service territory in which the project will take place. |
| **City** | The city in which the project will take place. |
| **County** | The county in which the project will take place. |
| **Applicable Risk Model** | Name and Version of Project Risk Model used to calculate Cost-Benefit Ratio. |
| **Circuit Protection Zone(s) or Isolated** | All Circuit Protection Zone(s)[28] or Isolatable Circuit |

[28] A Circuit Protection Zone is a segment of distribution circuit between two protection devices.

| Field Name | Field Description |
|---|---|
| **Circuit Segment(s)** | Segment(s) included in the project scope. |
| **Project Risk Rank**[29] | Results of the applicable risk model where Projects are ranked on a 1 to N basis, where 1 is the highest risk Project, and N is the lowest risk. |
| **Project Mean Risk**[2929] | Based on the applicable risk model, summation of the total risk of all pixels (100-meter x 100-meter cell) linked to a Project, divided by the total number of pixels. |
| **HFTD Tier** | CPUC High Fire Threat District Tier per D.17-01-009. Possible Values:<br>• Tier 2<br>• Tier 3<br>• Fire Rebuild |
| **Feasibility Score by Project**[2929] | Cost multiplier indicating the difficulty of undergrounding the Project based on presence of hard rock, water crossing, and gradient. The scale ranges from 1 to 3, with 3 being most challenging. The utility Phase 2 Application shall define each level of the scale. |
| **Cost-Benefit Ratio** | Cost-Benefit Ratio of the Undergrounding Project per D.22-12-027. Benefits must relate to the mitigation of overhead line miles not miles of undergrounding. |
| **Risk Reduction** | Risk Reduction of the Undergrounding Project per D.22-12-027. |
| **Unit Cost per Underground Mile** | Project Unit Cost per Mile of Undergrounding. |
| **Unit Cost per Overhead Mile** | Project Unit Cost per Mile of Overhead Exposure. |
| **Total Cost** | Total Undergrounding Project Cost. |
| **Risk Tranche(s)** | Risk tranches include a group of assets, a geographic region, or other grouping that is intended to have a similar risk profile such as having the same likelihood or consequence of risk events. |
| **System Hardening Alternative - Cost Benefit Ratio**[30,31] | System Hardening Alternative – Project Cost Benefit Ratio per D.22- 12-027 for each mitigation, or combination of mitigations, considered in place of undergrounding. |
| **System Hardening Alternative - Risk Reduction**[30 31, 31] | System Hardening Alternative – Project Risk Reduction per D.22-12- 027 for each mitigation, or combination of mitigations, considered in place of undergrounding. |

[29] This information is optional pending whether the large electrical corporation has the necessary data.

[30] Related to item 9 of the "Application Requirements" section.

[31] Provide data for all four rows for each system hardening alternative.

| Field Name | Field Description |
|---|---|
| **System Hardening Alternative - Unit Cost per Mile**[3030,31] | System Hardening Alternative Project Unit Cost per Circuit Mile for each mitigation, or combination of mitigations, considered in place of undergrounding.. |
| **System Hardening Alternative - Total Cost**[3030,3131] | System Hardening Alternative Total Project Cost, for each mitigation, or combination of mitigations, considered in place of undergrounding.. |
| **Customer Count** | Number of customers served by project. |
| **Total Planned UG Miles** | Total Planned UG miles for the project. |
| **UG 20XX Complete** | Total UG miles completed for the project at the time the SB 884 Application is filed. |
| **UG Year 1 Forecast** | UG miles for Year 1 of Project. |
| **UG Year 2 Forecast** | UG miles for Year 2 of Project. |
| **UG Year 3 Forecast** | UG miles for Year 3 of Project. |
| **UG Year 4 Forecast** | UG miles for Year 4 of Project. |
| **UG Year 5 Forecast** | UG miles for Year 5 of Project. |
| **UG Year 6 Forecast** | UG miles for Year 6 of Project. |
| **UG Year 7 Forecast** | UG miles for Year 7 of Project. |
| **UG Year 8 Forecast** | UG miles for Year 8 of Project. |
| **UG Year 9 Forecast** | UG miles for Year 9 of Project. |
| **UG Year 10 Forecast** | UG miles for Year 10 of Project. |

# Appendix 2: Statutory Requirements Cross-Reference

| Code Section | Statutory Language | Staff Proposal Section (Page Number) |
|---|---|---|
| 8388.5(a) | The commission shall establish an expedited utility distribution infrastructure undergrounding program consistent with this section. | Purpose (p. 1) |
| 8388.5(e)(1) | Upon the office approving a plan pursuant to paragraph (2) of subdivision (d), the large electrical corporation shall, within 60 days, submit to the commission a copy of the plan and an application requesting review and conditional approval of the plan's costs and including all of the following: | Conditions for Approval (p. 7-8) |
| 8388.5(e)(1)(A) | Any substantial improvements in safety risk and reduction in costs compared to other hardening and risk mitigation measures over the duration of the plan. | Application Requirements (p. 6) |
| 8388.5(e)(1)(B) | The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the large electrical corporation's historical undergrounding costs. | Application Requirements (p. 6)<br><br>Conditions for Approval (p. 8) |
| 8388.5(e)(1)(C) | How the cost targets are expected to decline over time due to cost efficiencies and economies of scale. | Application Requirements (p. 6) |
| 8388.5(e)(1)(D) | A strategy for achieving cost reductions over time. | Application Requirements (p. 6) |
| 8388.5(e)(3) | In reviewing an application submitted to the commission pursuant to paragraph (1), the commission shall consider not revisiting cost or mileage completion targets approved, or pending approval, in the electrical corporation's general rate case or a commission-approved balancing account ratemaking mechanism for system hardening. | Application Requirements (p. 5) |
| 8388.5(e)(4) | Upon the commission receiving an application pursuant to paragraph (1), the commission shall facilitate a public workshop for presentation of the plan and take public comment for at least 30 days. | Public Workshop & Comments (p. 7) |
| 8388.5(e)(5) | On or before nine months, the commission shall review and approve or deny the application. Before approving the | Application Conditional Approval, |

| Code Section | Statutory Language | Staff Proposal Section (Page Number) |
|---|---|---|
| | application, the commission may require the large electrical corporation to modify or modify and resubmit the application. | Denial, or Modification & Resubmittal (p. 4) |
| 8388.5(e)(6) | The commission shall consider continuing an existing commission-approved balancing account ratemaking mechanism for system hardening for the duration of a plan, as determined by the commission, and shall authorize recovery of recorded costs that are determined to be just and reasonable. | Conditions for Approval (p. 8)<br><br>Periodic Reviews for Authorization of Rate Recovery (p. 9) |
| 8388.5(i)(2) | The commission may assess penalties on a large electrical corporation that fails to substantially comply with a commission decision approving its plan. | Background (p. 3)<br><br>Penalties (p. 12) |
| 8388.5(j) | Each large electrical corporation participating in the program shall apply for available federal, state, and other no ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers. | Background (p. 3)<br><br>Application Requirements (p. 8)<br><br>Progress Report (p. 11) |