Decision 26-11-017 November 19, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Pacific Gas and Electric Company (U39E), Southern California Edison (U338E) and San Diego Gas & Electric Company (U902E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37.	Application 26-02-005

DECISION ADOPTING ADDITIONAL RULES FOR THE SENATE BILL 884 EXPEDITED UTILITY DISTRIBUTION INFRASTRUCTURE UNDERGROUNDING PROGRAM

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DECISION ADOPTING ADDITIONAL RULES FOR THE SENATE BILL 884 EXPEDITED UTILITY DISTRIBUTION INFRASTRUCTURE UNDERGROUNDING PROGRAM

Summary

This decision builds on Resolution SPD-15 and Resolution SPD-37 implementing Senate Bill (SB) 884 (McGuire, Stats. 2022, Ch. 819), codified at Public Utilities Code Section 8388.5. The SB 884 program is one of several regulatory pathways through which utilities may seek authorization to recover costs associated with undergrounding investments. Unlike traditional regulatory pathways, however, SB 884 establishes a voluntary, expedited framework for the review of 10-year undergrounding plans designed to substantially reduce wildfire risk, improve reliability, and achieve cost efficiencies. The program's longer-term planning horizon is intended to facilitate economies of scale, a sustainable supply chain, and declining undergrounding costs over time, ultimately benefiting ratepayers through more efficient and cost-effective wildfire risk reduction. This decision further implements the SB 884 framework by (1) adopting a standardized methodology for calculating Benefit-Cost Ratios that is consistent with the Commission's Risk-Based Decision-Making Framework, (2) determining the audit framework for verifying any undergrounding costs recorded to the program's one-way balancing account were properly recorded therein, and (3) adopting certain additional conditions (additional Phase 2 Conditions) to ensure that any costs ultimately recorded in the balancing account are just and reasonable.

This proceeding is closed.

1. Background

1.1. Senate Bill 884

Senate Bill (SB) 884 (McGuire, Ch. 819, Stat. 2022)[1] directed the Commission to establish an "expedited utility distribution infrastructure undergrounding program,"[2] (herein referred to as SB 884 program) in Tier 2 and Tier 3 High Fire-Threat Districts (HFTDs) and in wildfire rebuild areas for the state's large electrical corporations. The statute authorizes, but does not require, utilities with 250,000 or more customer accounts, currently meaning Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) to participate in the SB 884 program.

The SB 884 program is an important program for California's ratepayers, as it presents a unique, expedited, and long-term pathway for large electrical utilities to move overhead electric distribution lines underground in high-fire risk areas. The program's 10-year-long planning window should enable greater economies of scale, improved financing terms, and a more stable workforce - all of which should accrue to the benefit of California's ratepayers.

While large electrical corporations may elect to rely on other pathways to pursue their undergrounding, including, for example, through general rate case

[1] SB 884 added Section 8388.5 to, and amended Section 8385 of, the Public Utilities Code (Pub. Util. Code.) All code references are to the California Public Utilities Code unless otherwise noted.

[2] Pub. Util. Code Section 8388.5(a).

processes or the process under Section 8386.4,[3] we emphasize that large electrical corporations will, regardless of the procedural path they ultimately choose to pursue, bear the burden of demonstrating the prudency of their decisions through appropriate quantitative risk analysis and record evidence sufficient to support the requested cost recovery.

The SB 884 pathway begins when a participating large electrical corporation submits a 10-year electrical underground plan (herein, EUP) to the Office of Energy Infrastructure Safety (Energy Safety) for review. Energy Safety's review of an EUP takes place during "Phase 1" of the SB 884 program. During this "Phase 1," Energy Safety has nine months to approve or deny the EUP.[4]

Each EUP submitted to Energy Safety must address or include, among other things, (1) a means for prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits, (2) a comparison of undergrounding to alternative mitigations, such as covered conductor and rapid earth fault current limiter devices, and (3) an evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions, including the economies of scale necessary to reduce

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[3] Pub. Util. Code Section 8386.4 provides, in part, as follows: "(a) (1) The commission shall consider the cost of implementing each electrical corporation's [wildfire mitigation plan] in its general rate case proceeding and shall approve the costs for wildfire risk mitigation programs and activities it determines are just and reasonable. (2) In the commission's discretion, each electrical corporation may establish a memorandum account to track costs incurred for wildfire risk mitigation that are unforeseen and incremental to the wildfire risk mitigation programs and activities authorized in the electrical corporation's revenue requirements. The commission shall review the costs in the memorandum accounts and disallow recovery of those costs the commission deems unreasonable."

[4] Pub. Util. Code Section 8388.5(d)(2).

wildfire risk and mitigation costs and establish a sustainable supply chain.[5] Energy Safety may only approve an EUP if it finds the EUP will substantially increase reliability and substantially reduce the risk of wildfire.[6] Further information on the components of the Energy Safety review process can be found at Energy Safety's website.

If Energy Safety ultimately approves an EUP, the large electrical corporation then submits the EUP to the Commission for review and potential "conditional approval" of the EUP's costs. The Commission, like Energy Safety during "Phase 1," has nine months to review the EUP and its forecasted costs. This second step in the SB 884 program is referred to as "Phase 2" of the program.

This agency-to-agency review process is described in subsection (e)(1) of Section 8388.5, as follows:

> "(e)(1) Upon the office [Energy Safety] 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:
>
> (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.
>
> (B) The cost targets, at a minimum, that result in feasible and attainable cost reductions as compared to the

[5] Pub. Util. Code Section 8388.5(c).

[6] Pub. Util. Code Section 8388.5(d)(2).

large electrical corporation's historical undergrounding costs.

(C) How the cost targets are expected to decline over time due to cost efficiencies and economies of scale."[7]

If, after its review, the Commission decides to conditionally approve the EUP's costs, the SB 884 program moves into a subsequent and final "Phase 3," as is further described below, wherein, among other things, the large electrical corporation shall begin to implement its EUP.

1.2. Resolution SPD-15

The SB 884 program and its guidelines were first established by the Commission in Resolution SPD-15.[8] As discussed above, the program consists of up to three phases.

In "Phase 1," the large electrical corporation submits an EUP to Energy Safety for review, and if that EUP is approved by Energy Safety, then, in "Phase 2" the large electrical corporation submits an application (herein referred to as a Phase 2 Application) to the Commission, requesting review and "conditional approval" of the Plan's costs.[9]

Resolution SPD-15 established numerous Phase 2 Application requirements, each designed to facilitate the Commission's ability to meet its responsibility under Pub. Util. Code Section 451, to ensure that any

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[7] Pub. Util. Code Section 8388.5(e).

[8] Resolution SPD-15 *Senate Bill (SB) 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations* (March 7, 2024) (herein Resolution SPD-15).

[9] Resolution SPD-15 at 2.

"conditionally approved" costs are just and reasonable. These Phase 2 Application requirements are found on pages 6-10 of the *Senate Bill (SB) 884 Program: CPUC Guidelines* (Attachment 1) to Resolution SPD-15. They include, but are not limited to, requiring any participating large electrical corporation to:

(1) present cost forecasts for each year of the 10-year program;

(2) identify, for each year of the 10-year program, any forecasted costs that will be avoided by undergrounding (e.g. vegetation management costs); and

(3) present Benefit-Cost-Ratio (BCR) forecasts across all projects (for both undergrounding projects and alternative mitigations) expected to be completed in each year of the 10-year program.

Pursuant to Resolution SPD-15 and SB 884, the Commission then has nine months to expeditiously review the utility's Phase 2 Application, before then either denying the Phase 2 Application or conditionally approving its costs.

Assuming the Commission, after its review of the Phase 2 Application, decides to conditionally approve any EUP costs, the large electrical corporation will then establish a one-way balancing account wherein it may record and recover such conditionally approved costs, but only so long as such costs meet certain conditions that are further described herein (and which will be finalized by the Commission during Phase 2 of the program (collectively, the Phase 2 Conditions). All costs recorded to the balancing account throughout the duration of the program will be subject to audit (during "Phase 3" of the program, as further described below). The audit is designed to ensure that, among other

things, costs recorded to the balancing account met all Phase 2 Conditions as and when they were recorded to the balancing account.

Resolution SPD-15 established the concept of required Phase 2 Conditions that attach to the one-way balancing account to "protect ratepayers from unexpected and inefficient cost overruns" during the 10-year term of the program.[10] Via Resolution SPD-15, the Commission established five Phase 2 Conditions, which can be found on page 11 of the *Senate Bill (SB) 884 Program: CPUC Guidelines* (Attachment 1) attached to Resolution SPD-15. They are summarized as follows:

(1) total annual costs for each year of the 10-year program must not exceed an annual cost cap (such cap to be determined by the Phase 2 Decision based on the record in the Phase 2 proceeding) (herein, Phase 2 Condition #1);

(2) all third-party funding obtained throughout the duration of the program shall be applied to reduce any established cost cap for the year in which the third-party funding is obtained (herein, Phase 2 Condition #2);

(3) the average, actual unit costs for all projects completed in any given two-year period must not exceed some approved average unit cost (such unit cost to be determined by the Phase 2 Decision based on the record in the Phase 2 proceeding) (herein, Phase 2 Condition #3);

(4) the average, actual BCR for all projects completed in any given two-year period must not fall below some approved average BCR (such BCR to be determined

[10] Resolution SPD-15, Attachment 1, *SB 884 Program: CPUC Guidelines with Appendices* at 10.

by the Phase 2 Decision based on the record in the Phase 2 proceeding) (herein, Phase 2 Condition #4); and

(5) any further conditions (to be determined by the Phase 2 Decision based on the record in the Phase 2 proceeding) (herein, Phase 2 Condition #5).

According to Resolution SPD-15, the details of these five Phase 2 Conditions (i.e., their various caps and approved averages) are to be finalized during Phase 2 of the program via the Commission's Phase 2 Decision and collectively they "shall represent the conditions that the Commission finds are necessary and sufficient to determine that the costs authorized for recovery in the balancing account are just and reasonable."[11]

This is because if any costs are conditionally approved via a Phase 2 Decision, the large electrical corporation will establish the previously mentioned one-way balancing account to record and recover, through rates, any costs that meet the Phase 2 Conditions.[12] This balancing account mechanism was established to provide regulatory certainty to the large electrical corporations that choose to participate in the program by allowing them to recover their costs without undue delay, on an ongoing basis, once the undergrounding infrastructure is used and useful.[13] Hence, there is no after-the-fact

[11] Resolution SPD-15 at 5.

[12] Resolution SPD-15 at 5.

[13] Resolution SPD-15 at 8.

reasonableness review of the costs recorded to the balancing account within the SB 884 program.[14]

However, as mentioned above, Resolution SPD-15 did establish that all costs recorded to the balancing account do remain subject to audit and refund, to ensure that such costs meet the Phase 2 Conditions. As the Commission states in SPD-15: "[P]eriodic audits of the established balancing account will be performed to ensure that costs booked to the one-way balancing account meet the conditions established by the Phase 2 Decision (e.g., unit cost caps, BCR thresholds, etc.). If the audit demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund."[15]

In "Phase 3" of the SB 884 program, the utility shall implement its EUP, report on its progress, and begin booking its costs to the balancing account. The audit also takes place during Phase 3. Finally, given the inherent uncertainties associated with planning across a 10-year time period, and the fact that certain costs may, therefore, remain unforeseeable during the Phase 2 review process, Resolution SPD-15 also stated that, if the Commission conditionally approves cost recovery, it will also authorize the large electrical corporation to establish a memorandum account for recording any EUP costs that do not, ultimately, meet the Phase 2 Conditions when they're incurred.

[14] Resolution SPD-15 at 16.

[15] Resolution SPD-15 at 5-6. Cost-Benefit Ratio (CBR) and Benefit-Cost Ratio (BCR) are used interchangeably. D.25-08-032 (Phase 4 RDF Decision, R.20-07-013) revised CBR to BCR.

1.3. Energy Safety EUP Guidelines

After the issuance of Resolution SPD-15, Energy Safety addressed certain other matters relevant to SB 884 program and issued its own guidelines on February 20, 2025 pursuant to authority provided in subsections (c) and (d) of Pub. Util. Code Section 8388.5 for its review of EUPs during "Phase 1" of the program in a document referred to as, *10-Year Electrical Undergrounding Plan Guidelines (*herein referred to as *Energy Safety EUP Guidelines)*.[16]

The *Energy Safety EUP Guideline*s set forth several details regarding the EUP approval process that takes place at Energy Safety. Some of these details were not developed or available at the time of Resolution SPD-15's adoption.

The Energy Safety review process includes filtering all potential undergrounding projects through four increasingly specific screens (herein referred to as Screens 1, 2, 3, and 4) to create a final list of prioritized undergrounding projects.[17] As any project passes through any of the Energy Safety four screens, the uncertainty associated with that project's forecasted costs and benefits reduces.[18]

1.4. Resolution SPD-37

After Energy Safety released its *Energy Safety EUP Guidelines* and established its four screens, it became apparent, and the Commission recognized,

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[16] *Energy Safety EUP Guidelines* (February 10, 2025) is available on its website at: https://www.energysafety.ca.gov/news/2025/02/20/energy-safety-adopts-10-year-electrical-undergrounding-plan-guidelines/.

[17] Resolution SPD-37, *Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations* (December 4, 2025) at 5 (herein Resolution SPD-37).

[18] Resolution SPD-37 at 6-8.

that "significant changes" could be made to the forecasted economic metrics (total costs, unit costs, and BCRs) of any undergrounding project as it moved through Screens 1-4 and became more accurately scoped, especially as projects move through Screens 3 and 4.[19]

As we noted in Resolution SPD-37:

> "PG&E recognized that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs. PG&E stated that Screen 2... "is *well before a utility has developed a sound project cost estimate*. In PG&E's case, a sound cost estimate is developed after project estimating." [footnote omitted.]… It is only at [*Energy Safety EUP Guidelines*] Screen 4 when an undergrounding project is fully scoped, and estimating is complete that a reasonably accurate cost forecast can be provided."[20]

The Commission recognized that as a consequence of the *Energy Safety EUP Guidelines*, "only a small fraction" of the projects ultimately presented to the Commission for review in any Phase 2 Application will have progressed through at least Screen 3 of the *Energy Safety EUP Guidelines*.[21]

Following this, the Commission further updated and refined the SB 884 program in Resolution SPD-37. Among other things, Resolution SPD-37: (1) added several new Phase 2 Application requirements (including the requirement that only projects with forecasted BCRs greater than or equal to 1.0 can be

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[19] Resolution SPD-37 at 8.

[20] Resolution SPD-37 at 20, *citing* PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 7 (emphasis added), and at 6 ("PG&E indicates that Screen 2 cost estimates can vary from +100% to -50%, whereas at the completion of estimating that range is reduced to +20% to -15%.").

[21] Resolution SPD-37 at 7.

included in any Phase 2 Application); (2) adopted certain further details with respect to the audit process; and (3) adopted a cost cap for the Phase 3 memorandum account (capped as a percentage of the total sum of the 10 years of cost caps placed on the balancing account (such cap to be determined by the Phase 2 Decision based on the record in Phase 2). But most pertinent for the purposes of this Application (A.26-02-005), the Commission clarified that:

> "Because significant changes can be made to the economic metrics (total costs, unit costs, and cost benefit ratios) of an undergrounding project as it is more accurately scoped in [*Energy Safety EUP Guidelines*] Screens 3 and 4, the large majority of forecasted data available to the Commission at the time a Phase 2 Application is filed, and upon which its EUP cost approval conditions in the Phase 2 Decision will be based, **will not be sufficiently precise to provide the intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15.** Accordingly, this Resolution requires a future Phase 1 Application process to close any such gaps and ensure the Commission has the information essential to determining the appropriateness of cost recovery."[22]

The instant Application represents that process—the process the Commission established to close the gaps, and the process that is articulated in Resolution SPD-37, as designed to resolve, "…how Cost-Benefit Ratios (CBRs) must be calculated; whether large electrical corporations' proposed audit methodology is adequate; and whether any additional conditions [Phase 2 Conditions] should be placed on what costs are allowed to be recovered through the one-way balancing account adopted in Resolution SPD-15."[23]

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[22] Resolution SPD-37 at 8 (emphasis added).

[23] Resolution SPD-37 at 2 (citations omitted).

1.5. Application 26-02-005

On February 9, 2026, and pursuant to Ordering Paragraph 12 of Resolution SPD-37, PG&E, SCE, and SDG&E (collectively, the Joint Investor-Owned Utilities or the Joint IOUs) filed *Joint Application of Pacific Gas and Electric Company (U 39-E), Southern California Edison (U 338-E) and San Diego Gas & Electric Company (U 902-E) Requesting Commission Approval of Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37; Request For Expedited Schedule* (Application).[24]

The specific issues addressed in the Application and identified by the Commission in Resolution SPD-37 include, generally, what methodology the Commission should adopt for calculating BCRs in the context of the SB 884 program, whether any new, additional Phase 2 Conditions for reviewing costs recorded to the balancing account under the SB 884 program should be added, and what audit framework should be applied to verify the costs are properly recorded to the balancing account for the SB 884 program.

The Application filed by the Joint IOUs addresses each of these issues. The Joint IOUs provided official notice of the Application by serving a copy of the Application on the list of stakeholders referred to as the SB 884 Notification List[25] and on the Commission's official service lists for the following proceedings:

[24] All documents filed in this proceeding are available on the Commission's website at *Docket Card* by searching *A2602005*.

[25] SB 884 Notification List is a list of interested participants and parties to the Commission's process resulting in Resolution SPD-15 and Resolution SPD-37.

Application (A.) 25-05-009, A.23-05-010, A.22-05-016, and Rulemaking (R.) 18-10-007.[26]

On March 16, 2026, protests and responses were filed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Mussey Grade Road Alliance (MGRA), California Broadband & Video Association, Cellco Partnership LLC d/b/a Verizon Wireless, MCIMetro Access Transmission Services, LLC, and Pacific Bell Telephone Company d/b/a AT&T California (collectively, the Communications Providers), the Energy Producers and Users Coalition (EPUC), and the Coalition of California Utility Employees (CUE). The Utility Reform Network (TURN) filed a protest on March 13, 2026.

On March 26, 2026, the Joint IOUs filed a joint reply to the protests and responses.

On March 27, 2026, a prehearing conference was held to identify any disputed issues of law and fact, determine the need for evidentiary hearings, consider a schedule for resolving the proceeding, and address other matters as necessary.[27]

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[26] Joint IOUs Application at 47. A.25-05-009, *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027* (filed May 15, 2025); A.23-05-010, *Application of Southern California Edison Company (U 338-E) for Authority to Increase its Authorized Revenues for Electric Service in 2025, Among Other Things, and to Reflect that Increase in Rates* (filed May 12, 2023); A.22-05-016, *Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024* (filed May 16, 2022); and Rulemaking 18-10-007, *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)* (filed October 25, 2018).

[27] Reporter's Transcript (A.26-02-005 March 27, 2026, Prehearing Conference).

On April 10, 2026, President John Reynolds issued an *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Ruling) and determined the issues and procedural schedule for this proceeding. Attached to the Scoping Ruling was a *Staff White Paper on Benefit-Cost Ratio Methodology* (herein, Staff BCR White Paper) prepared by the Commission's Staff for consideration in this proceeding. The Staff BCR White Paper provides an in-depth discussion, analysis, and recommendations for various concepts related to the BCR methodology. The Scoping Ruling included a comment and briefing schedule on Application.

On May 12, 2026, parties were granted the opportunity to comment on the Staff BCR White Paper.

On June 9, 2026, Cal Advocates, TURN, and MGRA filed comments and counterproposals to the Application and the Staff BCR White Paper (herein referred to as "opening comments"). On June 9, 2026, the Joint IOUs also filed opening comments on the Staff BCR White Paper.

On July 7, 2026, the Joint IOUs, Cal Advocates, TURN, MGRA, and EPUC filed reply comments.

On August 7, 2026, the Joint IOUs, Cal Advocates, TURN, MGRA, EPUC, and the Communications Providers filed opening briefs.

On September 8, 2026, the Joint IOUs, Cal Advocates, TURN, MGRA, EPUC, and Pacific Bell Telephone Company d/b/a AT&T California (AT&T) filed reply briefs.

2. Submission Date

This proceeding was submitted on September 8, 2026, the date for filing reply briefs in this proceeding.

3. Issues Before the Commission

The April 10, 2026, Scoping Ruling included the following issues for consideration by the Commission:

1. **Benefit-Cost Ratios**. What standardized methodology should be adopted for calculating Benefit-Cost Ratios (BCRs) for applications filed by large electrical corporations for review pursuant to Pub. Util. Code Section 8388.5 (optional 10-year electrical undergrounding plans) that will assess cost efficiency and reasonably account for costs, benefits, discounting, risk treatment, and related inputs in a manner consistent with the Commission's Risk-Based Decision-Making Framework (RDF), including any refinements necessary to address wildfire mitigation and reliability impacts associated with PSPS [Public Safety Power Shut Offs], EPSS [Enhanced Powerline Safety Settings events], and other outage programs?
2. **Audit of Costs Recorded to Balancing Account**. What audit and accountability framework should be adopted to verify costs are properly recorded by a large electrical corporation to the balancing account associated with work performed pursuant to Pub. Util. Code Section 8388.5?
3. **Additional Cost Recovery Conditions**. What additional conditions, if any, are necessary to ensure that any costs recorded to the balancing account by an electric utility are just and reasonable?

4. Discussion

In Resolution SPD-37, the Commission directed additional consideration in this proceeding of the Commission's SB 884 program for reviewing an EUP and

conditional approval or denial of related costs with a specific focus on the following issues, described at a high level, as follows:

(1) Benefit-Cost Ratio Methodology;

(2) Audit Process;

(3) Additional, if any, Phase 2 Conditions.

The Commission considers these issues and the proposals by parties within the Commission's broad statutory authority over utility costs as set forth in Pub. Util. Code Section 451, Pub. Util. Code Section 8388.5(e), Pub. Util. Code Section 8386.4(a)(1), including those costs presented for "conditional approval" in any 10-year electric undergrounding plan.[28] The Commission has a fundamental responsibility under Pub. Util. Code Section 451 to ensure that rates are just and reasonable.

As noted above, any conditional approval will authorize the creation of a one-way balancing account to potentially recover plan costs contingent on the satisfaction of conditions placed on approval. In order to conditionally approve the costs of the EUP, the Commission must ensure that it has the information essential to determine the appropriateness of cost recovery. The Commission accordingly resolves in this decision issues not addressed in Resolution SPD-37, including how Benefit-Cost Ratios must be calculated; whether large electrical corporations' proposed audit methodology is adequate; and whether any

[28] The term "conditional approval" is set forth in Pub. Util. Code Section 8388.5(e)(1), stating, in part: "[T]he 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."

additional conditions should be placed on what costs are allowed to be recovered through the one-way balancing account adopted in Resolution SPD-15.

5. Benefit-Cost Ratio Methodology

The Commission adopted the use of the BCR framework in R.20-07-013, within its Risk-Based Decision-Making Framework (RDF). The BCR quantifies the relationship between mitigation benefits and costs, integrating capital expenditures, operations and maintenance (O&M) costs and savings, and monetized risk reductions into a single cost-efficiency metric. The BCR framework developed in D.22-12-027 is not specific to wildfire and reliability risk; rather, it examines all utility risks, including those related to other safety issues.[29] For this reason, in Resolution SPD-37, the Commission provided this direction to the Joint IOUs, stating that their proposed BCR methodology in the instant Application must:

> (1) "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications…." (2) "be designed to promote comparability, transparency, and traceability…." (3) "apply to the project level, and may allow for scalability to the portfolio level… [and] …." (4) "**outlin[e] how to calculate the CBR [BCR] for the purposes of EUPs** and provide more information on the calculation's key components."[30]

According to Resolution SPD-37, a proposed methodology for calculating BCR shall, at a minimum, include:

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[29] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 1.

[30] Resolution SPD-37 at 25-26 (bracketed numbers and emphasis added).

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

(2) Risk Scaling, which should address whether unscaled (i.e., risk-neutral) risk values should be used in the BCR calculations.

(3) Total Mitigation Benefit, which may include:

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

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

(4) O&M Costs associated with operating and maintaining the project.

(5) O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the No-Build Baseline.

(6) BCR Year Zero, defined as the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits.

(7) Interruption Cost Estimate (ICE) Calculator Granularity, the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability should be addressed.

(8) Backcasting, a method for recalculating BCRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an "apples-to-apples" comparison should be proposed.

The Joint IOUs propose a BCR methodology that, according to the Joint IOUs, "closely aligns" with the RDF methodology developed by the Commission in R.20-07-013.[31] Their Application includes a list of separate elements of their proposed BCR methodology with a brief description of each element.[32] Their proposal is summarized in a table, reproduced from the Joint IOUs' Opening Brief, below.

Table 1 – Components of Joint IOUs Proposal for BCR Methodology[33]

Topic	**Brief Description**	**Reference to RDF (R.20-07-013)**
Total Capital Cost and Total Operations & Maintenance (O&M) Costs	Consists of total capital and expense costs for mitigation implementation + net ongoing O&M costs. O&M costs and O&M savings will be reflected in the denominator of the BCR calculation.	D.25-08-032, Appendix A, p. A-19, Row 25 (definition of capital cost). D.24-05-064, Finding of Fact (FOF) 38.
Total Mitigation Benefit	Mitigation benefit can include all enterprise risks within the enterprise risk register, consistent with the RDF. All benefits associated with enterprise risks including wildfire and reliability risk reduction. This includes standard reliability and public safety (public contact with electrical equipment).	Benefit – "The reduction in Risk, as measured by the changes in Attribute levels, that would occur when a program or set of activities are implemented." D.2508-032, Appendix A, p. A-3.

[31] Joint IOUs Application at 4-5; Joint IOUs August 7, 2026, Opening Brief at 7.

[32] Joint IOUs Application at 4-5 (Table 1). Table 1 of the Joint IOU Application includes a reference to the Commission's exiting RDF (R.20-07-013) or indicates if an element is not required by the RDF (R.20-07-013).

[33] Joint IOUs August 7, 2026, Opening Brief at 9-11. A less detailed version of this table was initially provided in the Joint IOUs Application at 6-7 filed on February 9, 2026.

Risk Scaling	Allow utilities to apply their own risk-aversion frameworks and report results both with and without risk-aversion adjustments, showing scaled and unscaled values. IOU will make decisions based on scaled values if scaling is applied.	D.25-08-032, Appendix A, p. A-10, Row 7.

Discount Rate	Provide three discount rates: Weighted Average Cost of Capital (WACC); Societal Discount Rate; Hybrid Discount Rate. IOUs may select the discount rate it will use for decision-making. IOUs may also select different discount rates.	D.24-05-064 p. 102 "the approach we adopt here is to direct the IOUs to use three discount rate scenarios for mitigations. For each mitigation, the IOUs may express their preference for one of the three discount rate scenarios, but they must present the results of the three discount rate scenarios for their [BCR] calculation…."
ICE Calculator	RDF requires IOUs to use the current ICE Calculator to determine a standard dollar value of electric reliability risk unless the IOU proposes and justifies an alternative method. Given the time required to incorporate ICE values into risk models and decision-making tools, the IOUs will clearly identify the version of the ICE Calculator used in its assessment as well as subsequent reporting. The IOUs do not differentiate residential and non-residential ICE values by HFTD versus nonHFTD location. Instead, ICE values are estimated at the utility system level, with distinctions made by customer class (residential and nonresidential).	D.22-12-027, COL 13.
Backcasting	Use updated inputs (e.g., new RRUs, new risk models) to recalculate Benefit-Cost Ratios, premitigated risk, post-mitigated risk or other data points as required by the RDF, Commission Ruling or Commission Decision. The goal of a Backcast is to	D.25-08-032, Appendix A, p. A-3. D.25-08-032, Appendix A, p. A16, Row 15.1.

	establish a bridge between the prior inputs and the new inputs, which ensure an "apples-to-apples" comparison. The utility must provide a Backcast of postmitigated risk, risk reduction and Benefit-Cost Ratios submitted in the previous cycles of RAMPs and GRCs that are impacted by an update to the RRU's level of granularity. IOUs will perform a backcast only when it introduces substantive updates to its risk models.	Energy Safety EUP Guidelines, Section 2.8.5.3.
Net Salvage Values	Do not recommend incorporating net salvage value as a unique element of the BCR calculation. Salvage values are addressed via other cost considerations such as depreciation rates or Present Value Revenue Requirement ("PVRR") calculations.	Not required in RDF. SPD-37, SB 884 Program: CPUC Guidelines, 12/10/25, BCR Calculation, p. 5.
BCR Year Zero	BCR Year 0 is the year a utility's EUP becomes effective and should apply to all EUP projects. Defining BCR Year 0 as a single year—in this case the year a utility's EUP becomes effective—ensures consistency when comparing the BCRs for all projects in a utility's EUP portfolio.	Not required in RDF. SPD-37, SB 884 Program: CPUC Guidelines, 12/10/25, BCR Calculation, p. 6.

In the sections that follow, the Commission addresses the BCR proposals by the Joint IOUs, the recommendations in the Staff BCR White Paper, together with the comments and recommendations on both by Cal Advocates, TURN, MGRA, EPUC, Communications Providers, and AT&T.

5.1. O&M Costs and O&M Savings

In Resolution SPD-37, the Commission requested the Joint IOUs to offer a proposal in this proceeding on Total Capital Costs, which it defined as "capital expenditures tied to project implementation."[34] The Commission stated that the Joint IOU proposal on Total Capital Costs should address "[t]he **relationship**

[34] Resolution SPD-37 at 26.

between Total Capital Costs and other categories, such as Operating and Maintenance (O&M) Costs, O&M Savings, or Net Salvage values, ….“[35] Here, in Section 5.1, we address the relationship between Total Capital costs and the first two other categories mentioned in Resolution SPD-37 (i.e., Operating and Maintenance (O&M) Costs and O&M Savings).

As to this relationship, the Joint IOUs propose that “net ongoing O&M costs” (meaning the difference between O&M costs and O&M savings) should be placed in the denominator of the BCR alongside all capital expenditures tied to project implementation.[36] The Joint IOUs recommend that O&M costs be defined as the costs associated with operating and maintaining the project and that O&M Savings be defined as ”avoided O&M expenditures eliminated by the proposed project“ as compared to the No-Build Baseline.[37] The Joint IOUs argue this approach ”aligns to the RDF” by pointing out that the RDF states that for capital programs, such as undergrounding, ”the costs in the denominator [of the BCR] should include incremental expenses made necessary by the capital investment.”[38] The Joint IOUs also cite to a prior RDF decision which found that the financial components of a BCR ”are different in kind from the monetized safety and reliability components” of the BCR.[39] In other words, the Joint IOUs

[35] Resolution SPD-37 at 26 (emphasis added).

[36] Joint IOUs Application at 9.

[37] Joint IOUs Application at 8.

[38] Joint IOUs Application at 8 and fn. 20, *citing* D.25-08-032 (Phase 4 RDF Decision), Appendix A at A-18, Row 25.

[39] Joint IOUs Application at 6, *citing* D.24-05-064, Finding of Fact 38.

propose that neither O&M Savings nor O&M costs should be placed in the numerator of the BCR and made part of the BCR's Total Mitigation Benefit.

As to the Joint IOUs' first argument—that placing O&M Savings in the denominator of the BCR calculation aligns with the RDF—we emphasize that the RDF is silent on where O&M Savings should be placed. The RDF (R.20-07-013) does expressly define the risk-reduction numerator (defining "Benefit" in the BCR as "[t]he reduction in Risk, as measured by the changes in Attribute levels, that would occur when a program or set of activities are implemented")[40] and, Appendix A, p. A-19, Row 25 of the Phase 4 RDF decision, further states that "[f]or capital programs, the costs in the denominator should include incremental expenses made necessary by the capital investment." [41] O&M Savings, however, fall outside every operative definition the RDF supplies. They are not defined as a "Benefit" under the RDF's existing definition of that term because the RDF's definition covers only risk reduction measured by changes in Attribute levels, and not avoided expenditures. Furthermore, O&M savings are not defined as denominator "cost" under Row 25's plain text, because O&M Savings are clearly not an "expense made necessary by the capital investment;" they are, in fact, the very opposite—representing O&M expenditures rendered *unnecessary* relative to the No-Build Baseline. The RDF thus neither classifies O&M Savings as a benefit or cost, nor does it direct where they belong in the ratio, leaving a definitional gap that this proceeding must resolve.

[40] D.25-08-032 (Phase 4 RDF Decision), Appendix A, at A-3.

[41] D.25-08-032 (Phase 4 RDF Decision), Appendix A, at A-19, Row 25.

In this proceeding, the Commission understands that parties fill that gap in opposite directions, each anchoring its proposal to different portions of RDF's plain text. Cal Advocates relies on Row 25's further instruction that "the Benefits should reflect the **full set of Benefits that are the results of the incurred costs**,"[42] to argue that O&M savings should be categorized as a "benefit," reasoning that O&M savings result from the incurred capital cost and therefore belong in the numerator alongside present value risk reduction.[43] The Joint IOUs rely instead on the narrow definition of "Benefit" at A-3, arguing that because "Benefit" is confined to risk reduction in the RDF, O&M savings cannot classify as a benefit in the numerator, and instead, O&M savings should be classified as cost offsets in the denominator.[44] Notably, however, while the Joint IOUs state that O&M Savings should not be considered a part of the mitigation's benefit and that benefits should be defined solely as all benefits associated with any enterprise risk on the utility's enterprise risk register, the Joint IOUs also state:

> "The benefits included in the BCR calculation will reflect the full set of benefits associated with an undergrounding project that are the result of the incurred cost..."[45]

In response, Cal Advocates argues that standard cost-benefit literature commonly treats avoided costs (or savings) as benefits placed in the numerator, affirmatively citing to FEMA, USDOT, EPRI, and Krugman & Wells.[46] The Joint

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[42] D.25-08-032 (Phase 4 RDF Decision), Appendix A, at A-19, Row 25 (emphasis added).

[43] Cal Advocates July 7, 2026 Reply Comments at 4, 13, and 16–18.

[44] Joint IOUs Application at 9; Joint IOUs July 7, 2026, Reply Comments at 5–8.

[45] Joint IOUs August 7, 2026 Opening Brief at 12 (emphasis added).

[46] Cal Advocates June 9, 2026 Opening Comments at 16–17.

IOUs concede that standard cost-benefit literature commonly treats avoided costs (or savings) as benefits placed in the numerator, but they argue that such treatment only appears "in some general cost-benefit frameworks."[47] The parties thus draw opposite conclusions from the standard cost-benefit literature. Cal Advocates treats the general practice as controlling, while the Joint IOUs contend the RDF's bespoke, risk-reduction-specific definition of "Benefit" displaces it.

The Staff BCR White Paper also recognizes that standard cost-benefit literature commonly treats avoided costs (or savings) as benefits placed in the numerator,[48] and therefore recommends O&M savings be placed in the numerator of the BCR ratio, and included as part of its Total Benefit. However, the Staff BCR White Paper goes further, running both the Joint IOUs' proposal (which it refers to as "Method 1" in its Staff BCR White Paper) and two other proposals (which it refers to as Methods 2 and 3 in its White Paper) through six concrete examples to demonstrate the sensitivity of BCR outcomes to differing O&M structures.

Method 3 in the Staff BCR White Paper aligns with Method 1 (the Joint IOUs' proposal), except for the fact that Method 3, instead of placing O&M Savings in the denominator of the BCR ratio, places O&M Savings in the numerator (as part of the ratio's Total Benefit). The Staff BCR White Paper then shows that adopting the Joint IOUs' proposal (i.e., Method 1) fails under practical use cases, in that the Joint IOUs' proposal is "structurally incapable of

[47] Joint IOUs July 7, 2026 Reply Comments at 7.

[48] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 5-7 and 18-20.

handling high-savings projects (e.g., of handling substantial vegetation management displacement)."[49] According to the Staff BCR White Paper, Staff's recommended formula (Method 3) (which involves disaggregating O&M Savings from O&M costs and placing the O&M Savings in the numerator (as a Benefit) and the O&M costs in the denominator (as a Cost)) avoids situations where the denominator in the BCR becomes zero or negative.[50] The Staff BCR White Paper recommends that large electrical corporations explicitly report the O&M expenses for the No-Build Baseline, the avoided O&M costs (O&M Savings) resulting from displacing existing activities, and the new incremental O&M Costs introduced by the mitigation itself.[51] The Staff BCR White Paper refers to this recommendation as the "Disaggregated Formulation," or "Method 3."[52]

In response to the Staff BCR White Paper's observation that the Joint IOUs' proposal is not stable and positive under certain circumstances, the Joint IOUs suggest adding three "Guardrails" to the BCR calculation in the context of the SB 884 program to "enhance consistency, auditability, and comparability."[53]

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[49] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 26.

[50] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 24.

[51] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 21.

[52] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 20-21. The Disaggregated Formulation reports O&M components separately rather than as a single net value. O&M Savings are added to the numerator with risk reduction benefits, and new incremental O&M Costs are added to the denominator with capital costs.

[53] Joint IOUs June 9, 2026 Opening Comments at 16.

Guardrail 1 would introduce expanded reporting requirements that include additional variables. Guardrail 2 suggests presenting both risk reduction benefits and total net economic benefits. Guardrail 3 would set a denominator floor that would prevent negative valued BCRs.[54]

Cal Advocates supports the Staff BCR White Paper's recommendation, which includes placing all realized costs (both capital and O&M) in the denominator of the BCR ratio and all avoided costs (risk reduction benefits and avoided O&M (or O&M Savings)) in the numerator.[55] Cal Advocates disputes the Joint IOUs' characterization of their proposal as aligned with the RDF. Cal Advocates contends that treating avoided O&M costs as a negative cost in the denominator "fundamentally departs from accepted principles of economics, established cost-benefit analysis (CBA) practice, and the Commission's own Risk-Based Decision Making Framework," and recommends that the Commission adopt the disaggregated methodology recommended in the Staff BCR White Paper, which Cal Advocates asserts is consistent with the RDF.[56] Cal Advocates further argues that the Commission's Staff "methodology produces stable and comparable BCRs that accurately reflect the economic efficiency of competing wildfire mitigation alternatives without introducing systematic bias toward any particular mitigation strategy."[57] TURN likewise supports the Staff BCR White Paper's recommendation to adopt the "Disaggregated Formulation," where

[54] Joint IOUs June 9, 2026 Opening Comments at 16-19.

[55] Cal Advocates June 9, 2026 Opening Comments at 5-6 and 14-21.

[56] Cal Advocates August 7, 2026 Opening Brief at 3, 7–8.

[57] Cal Advocates August 7, 2026 Opening Brief at 7.

O&M Savings are reflected in the numerator and O&M Costs plus Capital Costs are reflected in the denominator.[58] TURN urges the Commission to make "Method 3's" data reporting requirements (reporting the O&M expenses for the No-Build Baseline, the avoided O&M costs (O&M Savings) resulting from displacing existing activities, and the new incremental O&M Costs introduced by the mitigation itself), binding filing requirements rather than aspirational guidance, arguing that without these disclosures neither the Commission nor intervenors can verify BCR inputs.[59]

MGRA also supports the Staff BCR White Paper's proposal to include O&M Savings in the numerator and O&M costs in the denominator. MGRA responds to the Joint IOUs' suggested three "guardrails" by first reminding the Commission that the Staff BCR White Paper's recommendation (Method 3) requires no such additional "guardrails."[60] Moreover, MGRA argues none of the "guardrails" suggested by the Joint IOUs address the other, inherent, underlying issues other parties flagged in connection with the Joint IOUs' proposal, including its tendency to produce negative BCRs even when net benefits are positive. MGRA contends the offered guardrails would obscure, rather than correct, these problems.[61]

After considering each of these arguments, the Commission adopts the "Disaggregated Formulation" (Method 3) as recommended in Staff BCR White

[58] TURN June 9, 2026 Opening Comments at 15, 16.

[59] TURN June 9, 2026 Opening Comments at 18.

[60] MRGA August 7, 2026 Opening Brief at 29-31.

[61] MGRA August 7, 2026 Opening Brief at 30 (*quoting* MGRA July 7, 2026 Reply Comments at 3).

Paper where: (1) O&M Costs are added to the denominator (as a cost), and O&M Savings are added to the numerator (as a benefit); and where (2) large electrical corporations shall separately report, for each project or RRU, the baseline O&M expenses under the No-Build Baseline, the O&M Savings, and the incremental O&M Costs used in the BCR calculation.[62] In other words, with respect to the methodology for accounting for O&M Savings and O&M costs in the BCR, and in relation to Total Capital Costs, the Commission adopts the following relationship and requires that this be used in connection with BCR's calculated in connection with the SB 884 program:[63]

$$BCR = \frac{Risk\ Reduction\ Benefits + O\&M\ Savings}{Capital\ Costs + O\&M\ Costs}$$

First, the Commission agrees with Cal Advocates that placing O&M Savings in the numerator, as part of the Total Benefit, follows from the RDF's (R.20-07-013) own text: where Row 25 directs that the numerator "reflect the full set of Benefits that are the results of the incurred costs."[64] Limiting benefits to risk reduction alone is inconsistent with SB 884, which directs that project prioritization be based on both risk reduction and cost-efficiency.[65] A risk-only

[62] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 20.

[63] For the avoidance of doubt, this requirement will apply to all BCRs presented to the Commission at any point in connection with the SB 884 program.

[64] Cal Advocates July 7, 2026 Reply Comments at 4, *citing* D.25-08-032 (Phase 4 RDF Decision) Appendix A at A-19, Row 25.

[65] Pub. Util. Code Section 8388.5(c) and (e).

focus in the numerator could crowd out cost-efficient opportunities within a constrained budget.[66] Moreover, the Commission observes that O&M Savings "result" from incurred capital costs.[67] Cal Advocates shows that O&M Savings only arise after the mitigation is built;[68] TURN points out that O&M Savings are not a capital "cost offset;" they don't reduce the capital recorded to rate base;[69] and the Staff BCR White Paper describes "costs" as resources that could have gone to other uses, and benefits as the monetized *outcomes* of the project.[70] The Commission agrees that costs represent the resources consumed to implement a mitigation; benefits represent the results of the incurred costs. O&M Savings are not a resource consumed; they only arise after the mitigation is implemented and are therefore a result of the investment, just as avoided wildfire risk is.

Second, the fact that O&M Savings are, in fact, expenditures rendered *unnecessary* relative to the No-Build Baseline, leaves the Joint IOUs' textual argument for including them in the denominator—the argument that the RDF states the denominator should include expenses "*made necessary*" by the capital investment—unpersuasive.[71]

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[66] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 13.

[67] D.25-08-032 (Phase 4 RDF Decision) at Appendix A-19 (Row 25); Cal Advocates July 7, 2026 Reply Comments at 4, 13.

[68] Cal Advocates July 7, 2026 Reply Comments at 9-10 and Figure 2.

[69] TURN August 7, 2026 Opening Brief at 5, 7.

[70] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at Attachment, *Staff BCR White Paper* at 9-10, stating "costs are the resources spent to implement a project, while benefits are the outcomes it generates."

[71] *See* Joint IOUs August 7, 2026 Opening Brief at 12, 17, 23.

Third, placing O&M Savings in the numerator aligns with standard benefit-cost analysis, under which avoided costs are consistently treated as benefits, and is consistent with the federal and academic guidance the Staff White BCR Paper relies upon (e.g., Office of Management and Budget, *Circular No. A-94* November 2023; U.S. Department of Transportation, *Benefit-Cost Analysis Guidance for Discretionary Grant Programs*, May 2025; and Boardman et al, *Cost-Benefit Analysis: Concepts and Practice*, 5th ed., Cambridge University Press, 2018.)[72]

Fourth, and independently, the Disaggregated Formulation is the only structurally robust option: it alone remains mathematically valid across all cost and risk conditions. The "Cost-Basis Formulation" (i.e., Method 1 in the Staff BCR White Paper, which the Joint IOUs support) nets O&M Savings against capital in the denominator and produces a negative or undefined BCR whenever O&M Savings exceed capital costs, precisely the high-savings condition created when undergrounding displaces substantial vegetation management. Only the "Disaggregated Formulation" or "Method 3" avoids both negative and zero denominators, making it stable not just for undergrounding but for evaluating BCRs consistently across capital-intensive and low-capital mitigations alike.[73]

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[72] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 4-7 (§ 2.1), 20 (§ 4.8).

[73] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 6, 20 (§ 4.8), 26–27 (§§ 5.8-5.9) (concluding Method 3 is "the most robust calculation method across all cost and risk conditions tested" and recommending the Commission adopt it).

As for how each component should be defined, the Commission agrees with the Staff BCR White Paper, finding that O&M costs should be defined, as the incremental "additional O&M expenditures required by the project or mitigation relative to the No-Build Baseline."[74] The RDF (R.20-07-013) locates that component in the denominator of the BCR ratio, directing that "[f]or capital programs, the costs in the denominator should include incremental expenses made necessary by the capital investment."[75] As for how O&M savings should be defined, the Commission finds they should be defined as the avoided O&M expenditures associated with the No-Build Baseline that are eliminated by the project or mitigation.[76]

5.2. Risk Scaling

In Resolution SPD-37, the Commission also requested that the Joint IOUs address risk scaling in their BCR proposal.[77] The Commission stated that the Joint IOUs' proposal on risk scaling "should address whether unscaled (i.e., risk-neutral) risk values should be used in the CBR [BCR] calculations."[78] The Commission previously addressed the concept of risk scaling in the RDF proceeding (R.20-07-013).

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[74] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 18 (§ 4.5).

[75] D.25-08-032 (Phase 4 RDF Decision) at Appendix A at A-19 (Row 25).

[76] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 23.

[77] Resolution SPD-37 at 26 and Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5-6.

[78] Resolution SPD-37 at 26.

According to D.25-08-032 (Phase 4 RDF Decision), risk scaling is described as follows: "Risk Scaling Function: A function or formula that specifies an attitude towards different magnitudes of Outcomes including capturing aversion to extreme Outcomes or indifference over a range of Outcomes."[79]

In D.25-08-032 (Phase 4 RDF Decision), the Commission describes how risk scaling can be used with the BCR at the "Cost-Benefit Approach Principle 6 – Risk-Adjusted Attribute Levels," which provides, in part, as follows: "Apply a Risk Scaling Function to the Monetized Levels of an Attribute or Attributes (from Row 6) to obtain Risk-Adjusted Attribute Levels. The Risk Scaling Function is an adjustment made in the risk model due to different magnitudes of Outcomes, which can capture aversion or indifference towards those Outcomes."[80] In other words, risk scaling impacts the size and magnitude of the various monetized risk reduction values that will be placed in the numerator of the BCR.

After review and consideration of considerable party debate on this topic within the RDF, the Commission in D.25-08-032 (Phase 4 RDF Decision) declined to modify the BCR to reflect risk-scaling in response to requests for changes by Commission Staff and some parties, stating: "We do not at this time adopt any of the other recommended changes to the RDF related to risk tolerance."[81] Instead, the Commission found that, as other parties suggested, more time was needed to fully consider this topic. The Commission placed this matter in a future

[79] D.25-08-032 (Phase 4 RDF Decision) at Appendix A at A-7.

[80] D.25-08-032 (Phase 4 RDF Decision), Appendix A at A-10 (Row 7).

[81] D.25-08-032 (Phase 4 RDF Decision) at 23.

proceeding, which is now ongoing in R.26-04-016, *Order Instituting Rulemaking to Refine the Risk-Based Decision-making Framework for Electric and Gas Utilities*.[82] In other words, the Commission has yet to adopt any particular risk scaling function; and for the time being—until R.26-04-016 or another Commission proceeding adopts a particular risk scaling function —the RDF currently *requires* utilities to present BCRs using risk-neutral values and *allows* them to, additionally, and at their own discretion, also present BCRs using risk scaling functions of their own design.[83]

The Joint IOUs acknowledge that the RDF requires the utilities to report unscaled (i.e., risk-neutral) BCR values in the RAMP Data Template (which is similar to the *SB 884 Project List Data Requirements Guidelines*),[84] and that the RDF allows utilities to submit a second dataset with scaled BCR values, if the utility so desires.[85] The Joint IOUs do not object to reporting BCR values both with and without a scaling function in the SB 884 program, provided each utility is allowed to make mitigation decisions based on either scaled or unscaled BCRs.[86]

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[82] D.25-08-032 (Phase 4 RDF Decision) at 28.

[83] D.25-08-032 (Phase 4 RDF Decision), Appendix A, p. A-10, Row 7 (emphasis added).

[84] The *SB 884 Project List Data Requirements Guidelines* were last updated on May 11, 2026 and are available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/sb-884-project-list-data-requirements-guidelines_051126.pdf. Pursuant to Ordering Paragraph 11 of Resolution SPD-37, Safety Policy Division Staff is authorized to make future updates and changes to the SB 884 Project List Data Requirements Guidelines and SB 884 Project List Data Template after hosting at least one technical working group meeting to present and discuss the changes.

[85] Joint IOUs Application at 10 (fn. 27) *citing* D.25-08-032 (Phase 4 RDF Decision) at 122.

[86] Joint IOUs Application at 10. "The IOUs acknowledge that the RDF requires large electrical corporations to report unscaled BCR values in the RAMP Data Template (which is similar to the

Footnote continued on next page.

Indeed, the Joint IOUs recommend that the Commission allow utilities to report BCR results applying both their (1) unique risk-averse scaled values and (2) risk-neutral, unscaled values.[87] The Joint IOUs further state that, in the unique context of the SB 884 program, the utility would then make its decisions based on scaled values if scaling is applied.[88] In support of their position, the Joint IOUs rely on the following Commission statement from R.20-07-013:

> "It is reasonable to afford the IOUs the same flexibility to incorporate Risk Attitude and Risk Tolerance into the Cost-Benefit Approach as they would under the current MAVF structure until further RDF refinements are adopted."[89]

As for whether the Commission should, here in this proceeding, adopt a particular risk scaling function or modify the Joint IOUs' risk-averse, scaled functions, the Joint IOUs state that such actions are more appropriately conducted in the Commission's ongoing rulemaking, R.26-04-016. In the interim,

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SB 884 Project List Data Requirements) so that SPD [the Commission's Safety and Policy Division] and parties can understand the implications of selecting and prioritizing proposed mitigations without the influence of scaled BCRs while also allowing utilities to submit another dataset with scaled risk values if they desire. [footnote omitted.] The IOUs do not object to reporting BCR values both with and without a scaling function in the EUP as long as a large electrical corporation is allowed to make mitigation decisions based on either scaled or unscaled BCRs, consistent with the RDF."

[87] Joint IOUs Application at 6, *citing* D.25-08-032 (Phase 4 RDF Decision), Appendix A, at A-10, Row 7.

[88] Joint IOUs Application at 6, *citing* D.25-08-032 (Phase 4 RDF Decision), Appendix A, at A-10, Row 7.

[89] Joint IOUs Application at 10 (fn. 25), stating: "D.22-12-027 [Phase 2 RDF Decision], p. 60, COL 14. While additional decisions have been issued in the RDF proceeding (Phase 3, D.24-05-064 and Phase 4, D.25-08-032), both still allow utilities to use a risk-averse scaling function."

the Joint IOUs contend that each utility should be permitted to continue applying its own risk scaling function in calculating BCRs for project selection.[90]

Cal Advocates argues the Commission should decline to adopt the Joint IOUs' proposed risk scaling methodologies and instead require project selection to be based on risk-neutral BCRs, unless and until a uniform risk aversion framework is refined in the newly opened rulemaking, R.26-04-016, *Order Instituting Rulemaking to Refine the Risk-Based Decision-making Framework for Electric and Gas Utilities*, in order to develop a unified approach to incorporating risk aversion based on the expected utility framework.

However, unlike the Joint IOUs, Cal Advocates argues that in the near term, in the SB 884 program, the Commission should evaluate costs using risk-neutral BCRs.[91] Cal Advocates argues that, only after an acceptable, unified framework is adopted into the new RDF proceeding, R.26-04-016, should the utilities be allowed to base decisions on risk-adjusted BCRs.[92] Cal Advocates flags that one of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects and that the Joint IOUs' proposal would permit each utility to apply its own, "independently developed" risk scaling function.[93]

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[90] Joint IOUs July 7, 2026, Reply Comments at 4-5, Attachment 1 at 4-5, 15-18.

[91] Cal Advocates June 9, 2026, Opening Comments at 7-8; Cal Advocates August 7, 2026, Opening Brief at 9-13.

[92] Cal Advocates June 9, 2026, Opening Comments at 7-8.

[93] *See* Cal Advocates August 7, 2026, Opening Brief at 10.

Like Cal Advocates, TURN opposes using risk-averse, scaled functions in the context of the SB 884 program, arguing they inflate risk reduction estimates and BCRs beyond what the underlying models actually support.[94] TURN recommends the Commission direct the utilities to present and use unscaled (i.e., risk-neutral) risk values, and achieve risk aversion by selecting projects with lower BCRs rather than inflating estimates.[95] TURN further clarifies that parties "are not asking the Commission to mandate a single scaling function in this proceeding — they are asking the Commission to decline to adopt either utility's current, unvalidated risk-scaling function for purposes of EUP selection while that validation work proceeds elsewhere."[96]

MGRA states that Commission must establish risk scaling guidance in this proceeding because any EUPs will be reviewed in accelerated proceedings (across 9 months) and no other regulatory process is likely to resolve the risk scaling question beforehand.[97] MGRA recommends that all EUPs include a

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[94] TURN June 9, 2026 Opening Comments at 1.

[95] TURN June 9, 2026 Opening Comments at 1.

[96] TURN August 7, 2026 Opening Brief at 14.

[97] MGRA June 9, 2026 Opening Comments at 4-6. In MGRA August 7, 2026 Opening Brief, MGRA appears to narrow its position as suggests a reasonable alternative is to defer this issue, stating: "MGRA's position is therefore that the reasonability of each utility risk-scaling function will need to be evaluated. Because the evidentiary basis in the current proceeding lacks the same weight as that of the GRCs, where there has been or will be testimony and evidentiary hearings. PG&E's and SDG&E's risk-scaling functions must be evaluated in the course of the GRCs, and it is therefore unlikely that a final determination regarding risks-scaling will be made in the current proceeding. However, if the Commission decides a determination is necessary, then the least harmful alternative is for the Commission to evaluate EUP applications using risk-neutral scaling due to the numerous errors and flaws in the current IOU risk-scaling approaches." MGRA August 7, 2026 Opening Brief at 7.

complete risk-neutral portfolio alternative alongside any risk-averse, scaled portfolio.[98] While acknowledging challenges of resolving this issue in this proceeding, MGRA also recommends that utilities provide full justification for their risk scaling function.[99]

EPUC generally supports MGRA, TURN, and Cal Advocates, stating: "MGRA, TURN and Cal Advocates raise valid concerns with the IOUs' risk scaling functions and prudently recommend adoption of unscaled BCRs for EUP project analysis until a standardized risk scaling approach is ultimately adopted. A uniform risk scaling methodology is necessary to ensure that undergrounding projects are evaluated consistently and comparably across the IOUs. The Commission should adopt the risk-neutral approach as the default methodology."[100]

The Staff BCR White Paper does not address risk scaling. The Communications Providers did not address this issue.

The Joint IOUs argue that the recommendations presented by other parties are not consistent with the existing RDF (R.20-07-013).[101] According to the Joint IOUs, the RDF (R.20-07-013) allows utilities, in addition to presenting a risk-neutral value, to apply a "Risk Scaling Function" to monetized attribute levels and provides that the function may be linear or convexly non-linear in order to

[98] MGRA June 9, 2026 Opening Comments at 26-32.

[99] MGRA June 9, 2026 Opening Comments at 26-32.

[100] EPUC August 7, 2026 Opening Brief at 18.

[101] Joint IOUs July 7, 2026 Reply Comments at 16.

capture aversion or indifference toward differing outcome magnitudes.[102] The Joint IOUs state that the existing framework contemplates the use of both risk-neutral and risk-adjusted perspectives, rather than restricting utilities to a single approach.[103]

The Joint IOUs acknowledge that parties disagree with certain aspects of their current risk-averse, scaling practices (e.g., there are parties on record herein who disagree with the means by which the Joint IOUs scale their risk).[104] For example, MGRA and Cal Advocates object to PG&E's and SDG&E's risk scaling practices. MGRA argues that PG&E's "market-based" approach, which applies a 7.5 multiplier drawn from PG&E's 2018 catastrophe bond to losses above $1 billion, rests on the mistaken assumption that PG&E must buy catastrophe bonds to cover uninsured wildfire risk.[105]

Cal Advocates adds that the CAT-bond multiplier reflects trigger design, investor required return, basis risk, and other market imperfections unrelated to ratepayer risk aversion, and that PG&E has since transitioned away from the instruments from which the multiplier was derived.[106]

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[102] Joint IOUs July 7, 2026 Reply Comments at 16.

[103] Joint IOU July 7, 2026 Reply Comments at 16 and fn. 27, *citing* D.25-08-032 (Phase 4 RDF Decision), Appendix A at A-10, Row 7 "Cost-Benefit Approach Principle 6 – Risk-Adjusted Attribute Levels."

[104] Joint IOUs July 7, 2026 Reply Comments at 16.

[105] MGRA March 16, 2026 Protest at 7.

[106] Cal Advocates June 9, 2026 Opening Comments at 25.

As to SDG&E, MGRA argues that SDG&E takes a power-law function derived from f-N curves and extends it to financial losses, a step that MGRA points out no cited reference or comparable industry takes.[107]

However, the Joint IOUs argue that a requirement to rely exclusively on risk-neutral evaluation in this proceeding would conflict with the flexibility explicitly provided in the RDF (R.20-07-013).[108] According to the Joint IOUs, differences in risk scaling approaches across the utilities are not a deviation from the RDF framework, but rather an intended feature that reflects differences in system characteristics, risk exposure, and operational context.[109] The Joint IOUs conclude by stating that "[t]he RDF does not require uniform application of a single methodology, nor has the Commission previously indicated that such uniformity is necessary or appropriate. Instead, the framework is designed to accommodate utility-specific conditions while maintaining overall analytical rigor."[110]

In response to the Joint IOUs' argument regarding differences in system characteristics and operational contexts, Cal Advocates demonstrates, in its opening comments, that under PG&E's risk scaling approach, the maximum multiplier would approach 7.5 for very large events, whereas under SDG&E's risk scaling approach there is no maximum, and the multipliers could easily

[107] MGRA June 9, 2026, Opening Comments at 21-22.

[108] Joint IOUs July 7, 2026 Reply Comments at 16.

[109] Joint IOUs July 7, 2026 Reply Comments at 16.

[110] Joint IOUs July 7, 2026 Reply Comments at 16.

exceed 20.[111] Cal Advocates argues this difference cannot reasonably be attributed to differences in service territory.[112] Additionally, MGRA argues that although PG&E and SDG&E arrive at their scaling functions through fundamentally different methodologies, both amplify catastrophic wildfire risk by a factor of roughly six or more and average risk by approximately four to five times — a convergence in outcome that MGRA contends reflects a shared preference for inflating justifiable risk spending rather than any difference in underlying system characteristics.[113]

After considering all arguments, the Commission finds that each large electrical corporation should use the same scaling approach within the context of the SB 884 program. One of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects. This is supported by Resolution SPD-37's directive to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."[114]

The Joint IOUs' proposal cannot meet this directive because it would have each utility apply its own independently developed risk-averse, scaled function, which would not promote the "comparability, transparency, and traceability in BCR calculations across large electrical corporations" that Resolution SPD-37

[111] Cal Advocates August 7, 2026 Opening Brief at 11-12.

[112] Cal Advocates August 7, 2026 Opening Brief at 11-12.

[113] MGRA March 16, 2026 Protest at 7.

[114] Resolution SPD-37 at 26 (bracketed numbers and emphasis added).

requires.[115] For the Joint IOUs to use a single scaling approach, the Commission would have to either (1) adopt a single, validated risk scaling function, or (2) require the utilities to use unscaled (i.e., risk-neutral) risk values. We do not determine in this proceeding whether any existing independently developed utility risk-scaling methodology is reasonable, unreasonable, superior, or inferior. Rather, the issue before us is whether a single standardized methodology should apply across large electrical corporations for purposes of the SB 884 program. We agree with the Joint IOUs, Cal Advocates, and TURN that, if the Commission elects to evaluate and potentially adopt a risk-scaling methodology, that undertaking should occur in a proceeding suited for that purpose and not in this proceeding, which establishes a methodology for the streamlined review and conditional approval of costs associated with a SB 884 undergrounding program.[116] Accordingly, we decline to evaluate the merits of the individual utility risk-scaling methodologies here.

Moreover, we also agree with MGRA that establishing risk scaling guidance in any Phase 2 Application proceeding of the SB 884 program may not be practical.[117] Resolving party disagreements on risk scaling functions during any expedited Phase 2 Application proceeding, across nine months,[118] where the large electrical corporation will be seeking conditional approval of the costs for a

[115] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5.

[116] Joint IOU July 7, 2026 Reply Comments at 4-5; Cal Advocates August 7, 2026 Opening Brief at 14; TURN August 7, 2026 Opening Brief at 13.

[117] MGRA March 16, 2026 Protest at 9-10.

[118] Resolution SPD-37 at 25.

10-year electric undergrounding plan is not the appropriate venue for making such decisions.

As for the second option (require the large electrical corporation to use risk-neutral values) we note that the RDF currently requires utilities to report risk-neutral values and, until further RDF refinements are adopted, allows utilities to present BCRs using risk scaling functions of their own design.[119] As Cal Advocates explains, absent a common risk scaling function, risk neutral BCRs preserve consistency across utilities and comparability among competing mitigation alternatives.[120] Furthermore, the SB 884 program already includes a BCR-based application requirement. Resolution SPD-37 requires that only projects with forecasted BCRs greater than or equal to 1 may be included in a Phase 2 Application. Because the Commission has not adopted a common risk scaling methodology applicable to all large electrical corporations, allowing each utility to rely on its own risk-scaling function in an SB 884 undergrounding application would result in overly constrained litigation of utility-specific risk-scaling methodologies due to the compressed statutory timelines governing the SB 884 program.

In addition, risk-neutral evaluation does not exclude low-frequency, high-consequence events (i.e., tail risk), which enter an unscaled BCR at their modeled likelihood and severity. We make no determination here as to whether, or how, risk attitude should additionally be reflected in RDF-based values; that question

[119] D.22-12-027, COL 14; D.25-08-032, App. A, Row 7

[120] Cal Advocates August 7 2026 Opening Brief at 14.

is within the scope of R.26-04-016.[121] Requiring large electrical corporations to use risk-neutral values in the SB 884 program is therefore consistent with the RDF. In their comments on the Proposed Decision, the Joint IOUs claim the decision's use of unscaled, risk-neutral values conflicts with the RDF.[122] We disagree. The decision does not modify, reject, or contradict the RDF framework and its goals. Rather, it applies the RDF within the specific context of the SB 884 program. The discussion above explains unique issues with the undergrounding program that benefit from building on the allowances made in RDF and builds on methodologies within the RDF framework. The Commission has the discretion to adopt measures to specific utility cases within boundaries of RDF guidelines. To this end, it can build on the RDF foundation by tailoring additional details to support SB884 differences. The RDF currently requires utilities to report risk-neutral values and permits utilities to additionally present BCRs using risk-scaling methodologies of their own design. The Commission's determination here simply establishes a uniform methodology for purposes of the SB 884 program. This approach is consistent with the RDF and advances the standardization, comparability, transparency, and traceability objectives established in Resolution SPD-37.

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[121] MGRA August 7, 2026 Opening Brief at 16-18, explaining that both PG&E and SDG&E already model wildfire consequences using power-law distributions, and their shared planning model simulates 24-hour fire spread to represent extreme events. . A risk-neutral BCR calculated on such a distribution includes catastrophic outcomes, in proportion to their modeled likelihood and severity, because tail risk enters the analysis through the consequence distribution (how likely and how severe extreme outcomes are), not the scaling function (which transforms each modeled consequence value before the expected value is taken).

[122] Joint IOUs Opening Comments on PD at 6, 8.

For these reasons, the Commission finds that unless and until the Commission explicitly adopts an alternative risk scaling function in the recently opened RDF proceeding (R.26-04-016) or another future proceeding , the single approach to be used for any BCR presented to the Commission in connection with the SB 884 program, including in a Phase 2 Application based on an EUP submitted to Energy Safety before the date of this decision will be unscaled (i.e., risk-neutral) risk values. If the Commission does decide in the new RDF proceeding (R.26-04-016) or another future proceeding to adopt another risk scaling function, then an EUP or Phase 2 Application filed or submitted thereafter may instead choose to use the Commission-adopted risk scaling function. It is possible that the Commission may find different risk scaling functions appropriate for different large electrical corporations, but that determination will occur outside of the Phase 2 Application and may be subsequently reflected in an EUP.

For the avoidance of doubt, these requirements will apply to all BCRs presented to the Commission at any point in connection with the SB 884 program.

These requirements shall apply to all uses of the BCRs in connection with the SB 884 program, including, but not limited to EUPs, applications, Phase 2 Conditions, ongoing reporting requirements, etc.

5.3. ICE Calculator

The ICE Calculator is generally described as follows:

> The Lawrence Berkeley National Laboratory (Berkeley Lab) Interruption Cost Estimate (ICE) Calculator is a publicly-available online tool that estimates the economic costs that electricity customers experience when their power is interrupted…Information on the economic costs customers experience when the lights go out is an important consideration for the design and prioritization of utility expenditures to improve the reliability and resilience of their distribution systems.[123]

The ICE Calculator's outputs (interruption cost estimates and reliability improvement valuations) impact the total benefit in a BCR, allowing decision-makers to assess the economic value of reliability gains.[124]

Resolution SPD-15 did not include guidance on the use of the ICE Calculator. The Commission's Staff held a Technical Working Group meeting to discuss the ICE Calculator as an element of the SB 884 review process.[125]

In Resolution SPD-37, the Commission requested that the Joint IOUs address the level of granularity (e.g., Customer Class separated by HFTD and Non-HFTD regions) that large electrical corporations should use to monetize the value of electric reliability when using the ICE Calculator.[126] In the RDF proceeding (R.20-07-013), the Commission engaged in a lengthy evaluation of the ICE Calculator. Then, when incorporating the use of the ICE Calculator into risk

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[123] D.22-12-027 (Phase 2 RDF Decision), Appendix C at 1, *citing* an excerpt from *Berkeley Lab Initiative to Update the Interruption Cost Estimate (ICE) Calculator Frequently Asked Questions* (provided to the Commission in September 2022). The ICE Calculator is available at https://icecalculator.com/home.

[124] *See, e.g.,* ICE Calculator FAQ: https://ice-calc-docs.s3.us-west-2.amazonaws.com/documents/FAQs+for+ICE+Calculator+2.pdf.

[125] Resolution SPD-37 at 33.

[126] Resolution SPD-37 at 27.

modeling, the Commission in D.22-12-027 (Phase 2 RDF Decision) required "IOUs to use the current ICE Calculator to determine a standard dollar [valuation] of electric reliability risk, unless the IOU proposes and justifies an alternative method…."[127]

When D.22-12-027 (Phase 2 RDF Decision) was issued, Lawrence Berkeley Livermore Lab was in the process of building the ICE Calculator model.[128] The model was finalized and shared publicly on or about April 2025.[129] The version currently used by the utilities of the model is sometimes referred to as ICE 2.0.[130]

In this proceeding, the Joint IOUs recommend using the ICE Calculator version 2.0 to determine a standard dollar value of electric reliability risk until a utility has time to fully review and evaluate the new information in ICE 2.1 and to then incorporate it into its risk models and mitigation decision-making

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[127] D.22-12-027, Phase 2 RDF Decision at 57, Finding of Fact 13, and Conclusion of Law 13. *Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots* (herein D.22-12-027 **(**Phase 2 RDF Decision)), Ordering Paragraph 2(b) at 64: "Each IOU shall use the most current version of the Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) Calculator to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute included in Appendix A." *See also,* D.22-12-027 (Phase 2 RDF Decision) at 57, Finding of Fact 13, and Conclusion of Law 13.

[128] D.22-12-027 (Phase 2 RDF Decision) acknowledges that the ICE Calculator (as built by Lawrence Berkeley National Laboratory does not produce results differentiated by HFTDs but rather produces results differentiated by residential, commercial, and industrial customers, (D.22-12-027 at 32) but rather "produces a dollar estimate of the cost to customers from electric service outages, with results that are differentiated by customer type (i.e., residential, commercial, and industrial)."

[129] The ICE 2.0 calculator was released at the end of April 2025 and concurrently Lawrence Berkeley National Laboratory posted the retirement of the ICE 1.0 calculator.

[130] Joint IOUs Application at 10.

tools.[131] The Joint IOUs recommend coordinating the integration of ICE 2.1—and any new updates to the ICE Calculator during the Commission's consideration of any future 10-year electric undergrounding plans and possibly longer —with risk model "version" changes as defined in the *Energy Safety EUP Guidelines*.[132] Energy Safety defines version changes as qualitative updates that substantially change the way that the risk model operates.[133] Under this approach, when a utility implements a model version change, an update could include updating from the ICE Calculator version the utility is currently using to an updated version of the ICE Calculator.[134]

As for the Commission's request in Resolution SPD-37 (to address the level of granularity that the Joint IOUs should use to monetize the value of electric reliability when using the ICE Calculator),[135] the Joint IOUs propose deriving the discrete Values of Service by customer type (e.g., residential and non-residential) from the ICE calculator without distinguishing between HFTD and non-HFTD

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[131] Joint IOUs Application at 10-11.

[132] Joint IOUs Application at 11 (fn. 29), *citing Energy Safety EUP Guidelines* at 39-40, Section 2.7.5.2. (Version and Calibration Changes, providing, in part: "The Large Electrical Corporation must describe its anticipated schedule for updating its modeling system and methods for recording these changes in a narrative section of one page or less in the EUP. The Large Electrical Corporation must establish a naming system to track historical versions and calibrations. The naming system must be described in a narrative section of one page or less in the EUP.

Version changes are qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a historical backtest (see Section 2.7.6).")

[133] Joint IOUs Application at 11.

[134] Joint IOUs Application at 11.

[135] Resolution SPD-37 at 27.

regions. The Joint IOUs point to PG&E's response in its *June 20, 2025, Response* to the April 22, 2025, ALJ Ruling filed in PG&E's ongoing general rate case,[136] to argue that the approach of using a single ICE value (instead of two, distinguishing between HFTD and non-HFTD regions) for each customer type across large electrical corporation's service territory avoids the risks and equity concerns that arise when reliability value for customers of the same type is differentiated by factors such as location or economic status.[137]

The Joint IOUs also offer a proposal for monetizing the reliability consequence at a specific location (e.g., circuit, feeder, circuit segment) impacted by a reliability risk event. The Joint IOUs propose to apply these discrete Values of Service (also referred to as VOS) by customer type from the ICE calculator to the respective customer mix at each location to get the "blended VOS" by location.[138] The Joint IOUs state that each utility may determine the appropriate level of granularity for individual locations to apply unique "blended" VOS depending on the nature of the reliability risk event and utility's grid

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[136] Joint IOUs Application at 11, *citing* June 20, 2025, *PG&E Response to the April 22, 2025, ALJ Ruling* issued in A.24-05-008 that directed the submission of additional information for A.25-05-009, 2027 General Rate Case (June 20, 2025) at 3-5, Sec. II. B. "Approach to Disaggregation for ICE 2.0."

[137] Joint IOUs Application at 11, *citing* June 20, 2025, *PG&E Response to the April 22, 2025 ALJ Ruling* issued in A.24-05-008 that directed the submission of additional information for A.25-05-009, 2027 General Rate Case (June 20, 2025) at 5, Sec. II. B. "Approach to Disaggregation for ICE 2.0." ("While differentiating the standard value of reliability by Residential and Non-Residential customers has its merit, PG&E is concerned about its application to the risk analysis at this time given large disparities in the $/CMI values between Residential and Non-Residential customers, which can lead to vastly different results depending on the granularity of the analysis and thus unintended consequences.")

[138] Joint IOUs Application at 11-12.

characteristics. The Joint IOUs provide an illustrative example of this calculation at Table 2 in the Application.[139]

The Staff BCR White Paper does not include a proposal regarding the ICE Calculator. MGRA does not address the ICE Calculator. Cal Advocates and TURN offer proposals.

Cal Advocates recommends that the ICE Calculator's derived Value of Service should use location-specific inputs.[140] Cal Advocates also recommends that the lookback data used to calculate the ICE derived Value of Service include data on Major Event Days and PSPS/EPSS and be limited to the timeframe that PSPS/EPSS was actively relied upon by utilities.[141] Cal Advocates opposes the Joint IOUs' proposal to use a "system-wide VOS and location-specific CMI [Customer Minute Interruption]" because, according to Cal Advocates, this will overstate reliability risk in locations that experience longer duration outages, such as HFTDs.[142] In terms of lookback data used to determine the Value of Service and the Customer Minute Interruption, Cal Advocates states the importance that the data capture all the events that affect ratepayers, as a reflection of the events that currently impact ratepayers. PG&E uses lookback data based on 2014-2023 which, according to Cal Advocates, fails to reflect Major

[139] Joint IOUs Application at 11-12.

[140] Cal Advocates June 9, 2026 Opening Comments at 8.

[141] Cal Advocates June 9, 2026 Opening Comments at 8.

[142] Cal Advocates June 9, 2026 Opening Comments at 8 and 43.

Event Days, PSPS events, EPSS outages.[143] Additionally, according the Cal Advocates, 2024-2025, a span of time omitted from the lookback data, is the most representative of current system operations.[144] Cal Advocates points out that, for example, if PG&E were to include Major Event Days and just use years representative of the current state of the system (i.e., with PSPS/EPSS, post 2018), average SAIDI would be over 4.5 times as great when compared with the method currently employed by PG&E (594.37 versus 130.47).[145] Cal Advocates states that the practical implication of excluding the Major Event Days, PSPS outages, and EPSS outages is that the Value of Service derived from the ICE Calculator will be greater than if these are included.[146]

TURN recommends that the Commission direct the Joint IOUs to supplement the values derived from the ICE calculator (2.0) by integrating data on customers with backup power into reliability risk calculations based on circuit and project-specific customer information.[147] TURN also includes several Data Responses from the Joint IOUs, as attachments to its Opening Comments.[148]

In the utility responses to questions about use of HFTDs in the ICE Calculator, the Joint IOUs explain that:

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[143] Cal Advocates June 9, 2026 Opening Comments at 44 and fn. 109 ("SAIDI means **system average interruption duration index,** which is the total number of interruption minutes in a given year.") (emphasis added).

[144] Cal Advocates June 9, 2026 Opening Comments at 44-45.

[145] Cal Advocates June 9, 2026 Opening Comments at 46.

[146] Cal Advocates June 9, 2026 Opening Comments at 46.

[147] TURN June 9, 2026 Opening Comments at 2.

[148] TURN June 9, 2026 Opening Comments at Attachments.

> "When monetizing reliability impacts using the ICE Calculator, the Joint Utilities apply the same customer-class ICE values uniformly, without differentiating those values based on whether customers are located in HFTD or non-HFTD areas. As described in the recently released ICE Calculator 2 Phase II Final Report, the ICE Calculator is based on a national, pooled set of interruption-cost surveys administered using identical instruments to statistically representative samples of the sponsoring utilities' residential and non-residential customers. The resulting customer damage functions estimate interruption costs for residential and nonresidential customers."[149]

In response to the recommendations of TURN and Cal Advocates, the Joint IOUs offer clarifications.[150] Regarding TURN's recommendation to direct the utilities to incorporate "backup generation" data into the ICE Calculator, the Joint IOUs clarify that the most recent update to the ICE Calculator (version 2.2) by Lawrence Berkeley National Laboratory incorporates the "percentage of customer with backup generators" as an "explanatory variable in estimating interruption costs, along with other customer and system characteristics."[151] The Joint IOUs state that because this data in now in the ICE Calculator, TURN's

[149] TURN June 9, 2026 Opening Comments, Attachments at 6, *citing* ICE-Calculator2 Phase II Final Report 27Jan2026 ICE Calculator 2 Phase II Final Report (Feb. 2026), Ch 5 ("Conclusion, Next Steps, and Caveats"), pp. 56-58.

[150] Joint IOUs July 7, 2026 Reply Comments at 19, 20 and 26-28.

[151] Joint IOUs July 7, 2026 Reply Comments at 19 and fn. 31, stating: "*See* Larsen, P. H., et al. (2025). ICE Calculator Version 2.0–2.1 Update Memorandum (Lawrence Berkeley National Laboratory), Table 2, p. 3 (identifying 'Percentage of Customers with Backup Generators' as an explanatory variable in ICE customer damage functions)."

recommendation is already reflected in the Value of Reliability derived from the ICE Calculator.[152]

In addition, the Joint IOUs clarify that, contrary to Cal Advocates, the Joint IOUs' proposal is not a "single undifferentiated system-wide reliability value" but rather the Joint IOUs propose deriving customer-class specific values (residential and non-residential) from the ICE Calculator and will apply this data to each circuit's actual customer mix to derive a new value reflecting what the Joint IOUs characterize as "location specific blend of value of service."[153] In this manner, the Joint IOUs claim the standardization provided by the ICE Calculator is preserved and granularity is incorporated via the additional utility data reflecting circuit-level customer composition.[154]

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[152] Joint IOUs July 7, 2026 Reply Comments at 19 and fn. 31, stating: "See Larsen, P. H., et al. (2025). ICE Calculator Version 2.0–2.1 Update Memorandum (Lawrence Berkeley National Laboratory), Table 2, p. 3 (identifying "Percentage of Customers with Backup Generators" as an explanatory variable in ICE customer damage functions)."

[153] Joint IOUs July 7, 2026 Reply Comments at 20 and fn. 32, stating: "*See* Joint IOU Application, pp. 11–13, (explaining that the Joint IOUs derive customer-class-specific interruption cost values from the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator and apply those values based on each circuit's customer composition to develop a circuit-specific value of service measure); *id.* at pp. 11–13 (describing derivation of customer-class ICE values and application to circuit-level customer mix)."

[154] Joint IOUs July 7, 2026 Reply Comments at 20-21. The Joint IOUs explain: "[T]he Joint IOU methodology captures location-specific reliability impacts without introducing inconsistencies that would arise from utility-specific or bespoke valuation approaches. The ICE Calculator produces representative, system-level estimates of interruption costs based on survey-derived customer damage functions (CDFs) and aggregated inputs. Importantly, as documented in the ICE Calculator 2.0 Phase II Final Report, not designed for intra-utility geographic variation. The ICE survey framework does not explicitly incorporate utility-specific spatial factors or localized operational conditions and instead reflects average customer responses across broad populations. As a result, the tool is not calibrated to produce reliable location-specific or circuit-

Footnote continued on next page.

Lastly, the Joint IOUs point to certain limitations in the intended use of the ICE Calculator that they state weighs against adopting the recommendations of TURN and Cal Advocates. The Joint IOUs state:

> "[A]lthough the ICE Calculator enables estimation of interruption costs across scenarios, it "does not furnish interruption cost information for specific individual electricity customers" and should be used as a general guide rather than as a basis for customer-specific decision-making.[155] ICE Calculator documentation further confirms that the tool was not designed to estimate costs associated with outages beyond 24 hours or large-scale outage events. The ICE Calculator documentation states that more work needs to be done to "estimate the cost of widespread, long-duration power interruptions" in order "to calibrate regional economic models."[156]
>
> "These limitations are important to note. Extending ICE-based relationships beyond their intended range introduces structural uncertainty and may produce results that are not empirically validated."[157]

The Commission finds that for the purposes of the SB 884 program, large electrical corporations should use, in line with the Joint IOUs' recommendation, the ICE Calculator version 2.0 to determine a standard dollar value of electric reliability risk until the utility has time to fully review and evaluate the new information in the ICE Calculator 2.1 and to then incorporate it into its risk

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specific level estimates and applying ICE outputs at highly granular levels may introduce additional uncertainty or estimation errors."

[155] Joint IOUs July 7, 2026 Reply Comments at 20 and fn. 34, *citing - See* Ghodeswar, Archana, Mahabir Bhandari, & Bruce Hedman. (2024). Quantifying the Economic Costs of Power Outages Owing to Extreme Events: A Systematic Review, Renewable and Sustainable Energy Reviews.

[156] Joint IOUs July 7, 2026 Reply Comments at 20 (fn. omitted).

[157] Joint IOUs July 7, 2026 Reply Comments at 20 (fn. omitted).

models and mitigation decision-making tools. The Commission agrees with coordinating the integration of the ICE Calculator 2.1—and any new updates to the ICE Calculator during the Commission's consideration of any future 10-year electric undergrounding plans and possibly longer —with risk model "version" changes as defined in the *Energy Safety EUP Guidelines*.

As for the Commission's request in Resolution SPD-37 to address the level of granularity that the Joint IOUs should use to monetize the value of electric reliability when using the ICE Calculator, the Commission finds that for the purposes of the SB 884 program, large electrical corporations should use two ICE Calculator values (distinguishing between HFTD and non-HFTD regions) for each customer class (residential and non-residential) across large electrical corporation's service territory (i.e., four total Value of Service be produced). For projects located in a Tier 2 or 3 HFTD, the Commission finds that HFTD-region $/CMI (Customer Minute Interruption) values consistent with Table 6 of the *SB 884 Project List Data Requirements Guidelines* be used in the BCR reliability calculation. For projects located in a Wildfire Rebuild Area outside a Tier 2 or 3 HFTD and for spans outside the HFTD boundary included under *Energy Safety EUP Guidelines* § 2.4.3.1,[158] the Commission directs that the corresponding $/CMI (Customer Minute Interruption) values (HFTD or Non-HFTD, residential or non-residential) be used.

The Commission agrees with the Joint IOUs' proposal to monetize reliability consequences at specific locations (e.g., circuit, feeder, circuit segment)

[158] *Energy Safety EUP Guidelines* at 16.

impacted by a reliability risk event, and with the proposal to use the calculator at each location to get a "blended VOS'" by location. However, the Commission disagrees with the Joint IOUs that each utility may determine the appropriate level of granularity for individual locations to apply unique "blended" VOS and we specify that the "blended VOS" be calculated at the RRU level. Otherwise, the Commission adopts the Joint IOUs' proposal in full.

One of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects. This is supported by Resolution SPD-37's directive to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."[159] The Joint IOUs' proposal cannot meet this directive because it would have each utility determine the appropriate level of granularity for individual locations, which would not promote the "comparability, transparency, and traceability in BCR calculations across large electrical corporations" that Resolution SPD-37 requires.[160] Furthermore, because the SB 884 program is limited to circuit segments located in a Tier 2 or 3 HFTD or a wildfire rebuild area, the Commission finds the Value of Service values used to monetize reliability benefits in the BCR should be derived from the eligible area customer population (rather than, as the Joint IOUs' propose, the system-wide customer

[159] Resolution SPD-37 at 26 (bracketed numbers and emphasis added).

[160] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5.

population).[161] As EPUC points out, the *SB 884 Project List Data Requirements Guidelines* already require this distinction: Table 6 requires data for every ICE Calculator input for HFTD Region and specifies the residential and non-residential dollar values per customer-minute interrupted for each HFTD Region.[162]

As Cal Advocates finds, "[u]sing a system-wide VOS [as opposed to distinguishing between HFTD and non-HFTD regions] ... will overstate reliability risk in locations that experience longer duration outages, e.g., HFTDs."[163] In other words, because SB 884 projects will be implemented in HFTDs and wildfire rebuild areas, the Commission finds that when measuring the reliability benefits produced by such projects, such measurement should distinguish between the Value of Service to customers residing in HFTDs and those residing outside the area. In their comments on the Proposed Decision, the Joint IOUs argue that the use of HFTD-specific values conflicts with SB 884's objective of improving reliability in high fire-threat areas because it may produce lower quantified reliability benefits than their proposed system-wide approach. We disagree. The decision adopts a methodology that the Commission finds appropriately measures reliability benefits for projects located in HFTDs and

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[161] *Energy Safety EUP Guidelines* at 12 (§ 2.4.1).

[162] EPUC August 7, 2026 Opening Brief at 19, *quoting* SB 884 Program: CPUC Guidelines; Appendix 1 (Project List Data Requirements Guidelines), Table 6 (Interruption Cost Estimate Calculator Inputs) at A1-30 to A1-31 (requiring ICE Calculator inputs, including SAIDI and SAIFI, to be reported by HFTD_Region, and requiring the residential and non-residential dollar values per customer-minute interrupted to be reported for each HFTD_Region); EPUC July 7, 2026 Reply Comments at 12.

[163] Cal Advocates June 9, 2026 Opening Comments at 43-44.

wildfire rebuild areas. As discussed above, the Commission agrees with Cal Advocates that the use of system-wide values may overstate reliability benefits in locations that experience longer duration outages. The fact that a methodology may produce different quantified benefits than a system-wide approach does not establish inconsistency with SB 884's reliability objectives.

Finally, while the Joint IOUs share that the ICE Calculator is based on a national, pooled set of surveys that results in customer damage functions that estimate interruption costs for residential and nonresidential customers, we do not find this fact dispositive. Constructing and operating the model are distinct actions, and nothing about the survey's customer sampling dictates whether inputs must be system-wide, as opposed to HFTD-specific. Nor have the Joint IOUs identified any provision of SB 884 or the RDF requiring the use of system-wide Value of Service values. Accordingly, we continue to find it reasonable to require HFTD-specific values for purposes of the SB 884 program.

5.4. Discount Rate

As the Commission previously found, "[d]iscount rates are necessary to account for the time-value of money and to put future costs and future benefits in present-day dollars. This allows for comparisons both between costs and benefits within a risk mitigation as well as comparisons across risk mitigations. The use of discount rates is implicit in the RDF CBR calculations."[164]

[164] D.24-05-064 (Phase 3 RDF Decision) at 99.

Resolution SPD-15 did not include guidance on the use of the Discount Rate as part of the BCR in the context of SB 884 review process for "conditional approval" of costs.

On April 11, 2025, CPUC Staff issued *Post-Workship Questions* that included the following question regarding issue of Discount Rates: How should the utility calculations of BCR be presented when using the three discount rate scenarios (Weighted Average Cost of Capital, Social and Hybrid) required by D.24-05-064?[165]

On June 3, 2025, the Commission Staff held a Technical Working Group meeting to discuss the Financial Inputs for the BCR, including Discount Rates.[166]

In Resolution SPD-37, the Commission requested the Joint IOUs to address the Discount Rate in a BCR proposal in this proceeding, stating:

> "In the *Post-Workshop Questions for Stakeholders Regarding the CPUC SB 884 Guidelines* issued on April 11, 2025, Staff solicited stakeholder input on whether the Commission should provide additional guidance for CBR [BCR] calculations made in the context of SB 884. [footnote omitted]. The questions explored a variety of topics related to CBR [BCR] calculations, including the appropriate granularity for monetizing electric reliability, **discount rate scenarios**, risk -scaling, and the treatment of combined benefits (impacts on both wildfire and reliability) of mitigations."[167]

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[165] Commission Staff issued these questions after a Technical Working Group Workshop held on April 8, 2025. D.24-05-064 (Phase 3 RDF Decision).

[166] *See,* Commission website on SB 884 implementation, Technical Working Group#1 and Master Slides at https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/electric-undergrounding-sb-884.

[167] Resolution SPD-37 at 24 (emphasis added.)

In the D.24-05-064, the Commission described the use of discount rates for the purpose of the BCR stating that one of the topics in the RDF proceeding (R.20-07-013) is:

> "…the use of discount rates in the RDF CBR [BCR] calculation. Discount rates are necessary to account for the time-value of money and to put future costs and future benefits in present-day dollars. This allows for comparisons both between costs and benefits within a risk mitigation as well as comparisons across risk mitigations. The use of discount rates is implicit in the RDF CBR calculations. The questions motivating the discussion on discount rates were whether the different kinds of costs and benefits (e.g., financial versus monetized) should have different discount rates, whether different kinds of mitigations warrant different discount rates, and what the applied discount rates should be. Both SPD [the Commission's Safety and Policy Division] and TURN provided proposals on discount rates."[168]

After lengthy consideration of all positions in the RDF proceeding (R.20-07-013), the Commission in D.24-05-064 (Phase 3 RDF Decision) modified the BCR by incorporating sensitivity analysis that required the utilities to present the BCR using three different discount rate scenarios:[169] Weighted Average Cost of Capital (WACC) Discount Rate Scenario; Societal Discount Rate Scenario

[168] D.24-05-064 (Phase 3 RDF Decision) at 99. The Commission addresses discount rates at 99-105.

[169] D.24-05-064 (Phase 3 RDF Decision) at 3 and 10, which identifies discount rates as one of the issues within the scope of the proceeding at (f.): "Should the Commission provide guidance regarding the use of varying discount rates (i.e., dual-rate discounting) for mitigation costs and benefits within the Cost-Benefit Ratios in RDF? Should the Commission identify an appropriate discount rate (or range of discount rates) for mitigation costs and benefits in the RDF? Should the Commission authorize IOUs to vary their use of discount rates by mitigation?"

(Societal); and Hybrid Discount Rate Scenario (Hybrid).[170] The Commission went on to state, that within the RDF, "For each mitigation, the IOUs may express their preference for one of three discount rate scenarios, but they must present the results of the three discount rate scenarios for their CBR [BCR] calculation…."[171]

In this proceeding, which addresses the unique SB 884 program context, the Joint IOUs recommend that, consistent with the outcome in R.20-07-013, the following: (1) BCR calculations be presented under the above three scenarios and (2) that each utility be allowed to make its risk-based decisions based on the discount rate of its choice, as they argue is allowed by the RDF.[172] The Joint IOUs state that, according to D.24-05-064 (Phase 3 RDF Decision), each utility can select whichever discount rate it chooses to rely upon but must use that same rate formulation for the duration of the Section 884 Application process.[173]

For example, the Joint IOUs state that, if a utility chooses to use the Societal rate with its EUP, it must use the Societal rate for the life of its EUP, though it may vary the specific Societal rate used if inputs into the formulation of the Societal rate change.[174] Therefore, for purposes of the SB 884 program, the Joint IOUs state that, while utilities are required to calculate BCR values using three discount rates, the Commission should allow utilities to make risk-based decisions, within the context of the SB 884 program, using the discount rate of

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[170] D.25-08-032 (Phase 4 RDF Decision), Appendix A at A-19, Row 25.

[171] D.24-05-064 (Phase 3 RDF Decision) at 102.

[172] Joint IOUs Application at 14 and fn.32, *citing* D.24-05-064 (Phase 3 RDF Decision) at 102.

[173] Joint IOUs Application at 14.

[174] Joint IOUs Application at 14.

their choice.[175] Moreover, the Joint IOUs state that this discount rate would remain constant throughout the SB 884 process.[176]

Several issues emerged in this proceeding regarding the discount rate. First, whether D.24-05-064 (Phase 3 RDF Decision) permits the utilities to decide which scenario to rely upon for its decision-making processes. Second, whether the utilities all are required to use the same discount rate for their decision-making process. Lastly, whether the Commission finds it reasonable to adopt a unique approach to discount rates in the context of the SB 884 process.

The Staff BCR White Paper did not take a position on discount rates. MGRA and Communications Providers do not address this issue.

Cal Advocates interprets D.24-05-064 (Phase 3 RDF Decision) as not giving the utility the discretion to choose which discount rate to rely upon for its decision-making process.[177] Cal Advocates recommends that the Joint IOUs use the same discount rate for evaluating mitigation projects.[178] Cal Advocates suggests that no reasonable basis exists to allow utilities operating under the same regulatory framework and evaluating similar mitigation projects to apply different discount rates in the estimation of costs and benefits.[179] According to Cal Advocates, because the discount rate directly affects the present value of mitigation investments and therefore the relative attractiveness of competing

[175] Joint IOUs August 7, 2026 Opening Brief at 26.

[176] Joint IOUs August 7, 2026 Opening Brief at 26.

[177] Cal Advocates June 9, 2026 Opening Comments at 48-49.

[178] Cal Advocates June 9, 2026 Opening Comments at 8-9 and 47-49.

[179] Cal Advocates June 9, 2026 Opening Comments at 48.

mitigation strategies, allowing utility-specific discount-rate selection would result in differences in estimated BCRs that are driven not by differences in underlying system risk or mitigation effectiveness, but rather by differing choice of analytical assumptions.[180]

EPUC largely agrees with the position of Cal Advocates and concludes that "[t]he Commission should therefore designate a single discount-rate framework, preferably the Weighted-Average Cost of Capital scenario, to ensure transparent, consistent, and comparable evaluations across utilities."[181] EPUC states this should be the case given that ratepayers pay the costs and receive the benefits of undergrounding.[182]

TURN states that, pursuant to D.24-05-064 (Phase 3 RDF Decision), the utilities must present the results of the three discount rate scenarios for their BCR calculation in any EUP.[183] TURN recommends that the Commission modify this approach in this proceeding to reflect certain topics it raised in its white paper presented in the Commission's SMAP proceeding.[184] TURN recommends a three-step discounting discipline: (1) remove inflation before applying the real discount rate; (2) standardize cost calculation as Present Value Revenue

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[180] Cal Advocates June 9, 2026 Opening Comments at 48.

[181] EPUC August 7, 2026 Opening Brief at 22.

[182] EPUC July 7, 2026 Reply Comments at 12-13.

[183] TURN June 9, 2026 Opening Comments at 2.

[184] TURN June 9, 2026 Opening Comments at 7-8 and fn. 18, *citing* a white paper: Synapse Energy Economics on behalf of TURN, *Application of Discount Rates for Assessing Cost-effectiveness of Utility Risk Related Investments,* October 2023, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/discount-rates-andrisk-modeling_synapse_101123.pdf.

Requirement (PVRR) across all utilities; and (3) use a single discount rate for both numerator and denominator to avoid biasing the BCR.[185]

In response, the Joint IOUs suggest that the Commission decline to adopt recommendations that attempt to revisit settled or actively considered policy issues, including the discount rate standardization, which the Joint IOUs state either have been addressed in prior RDF decisions or are currently under consideration in separate Commission proceedings better suited for comprehensive policy evaluation.[186] The Joint IOUs state that, within the RDF framework, BCRs are not intended to facilitate comparisons across utilities, rather, they are used to support prioritization of mitigation alternatives within each individual utility's system.[187] According to the Joint IOUs, these metrics are used to assess and rank risks and mitigations within utility specific RAMP and general rate case filings.[188] The Joint IOUs state that this framework of choice does not introduce arbitrary variation, it simply acknowledges the differences in regulatory cost of capital, policy perspective, and analytical context inherent to each utility.[189]

After considering these arguments, the Commission finds that large electrical corporations, within the unique context of the SB 884 program, should rely on a single, common discount rate scenario—the WACC rate— for all uses of

[185] TURN June 9, 2026 Opening Comments at 7-8.

[186] Joint IOUs July 7, 2026 Reply Comments at 26.

[187] Joint IOUs August 7, 2026 Opening Brief at 26.

[188] Joint IOUs August 7, 2026 Opening Brief at 26.

[189] Joint IOUs August 7, 2026 Opening Brief at 26.

the BCRs in connection with the SB 884 program, including, but not limited to EUPs, applications, Phase 2 Conditions, ongoing reporting requirements, etc. One of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects. This is supported by Resolution SPD-37's directive to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."[190] The Joint IOUs' proposal cannot meet this directive because it would have each utility choosing its own discount rate, which would not promote the "comparability, transparency, and traceability in BCR calculations across large electrical corporations" that Resolution SPD-37 requires.[191] Because the discount rate is an analytical assumption that directly determines present value of costs and benefits used in the BCR calculation, utility-specific selection of a scenario could mean differences in estimated BCRs across large electrical corporations are driven not by differences in underlying system risk or mitigation effectiveness, but rather by differing choices of discount scenario assumptions. This is not a theoretical concern. The three RDF scenarios differ materially in magnitude, and even small differences in discount rates can alter calculated BCRs and change project rankings. Thus, a standardized evaluation methodology requires a standardized discount rate.[192]

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[190] Resolution SPD-37 at 26.

[191] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5.

[192] Cal Advocates August 7, 2026 Opening Brief at 17-18.

We also note that no intervening party opposes a common discount rate. Cal Advocates and EPUC each recommend that a single, Commission-approved discount rate govern BCR calculations in this program, and TURN raises the same concern with utility discretion over the rate; the dispute is whether the utility, rather than the Commission, selects it.[193]

Additionally, while the Joint IOUs argue that the RDF (R.20-07-013) allows each utility to make risk-based decisions based on the discount rate of its choosing, we agree with Cal Advocates that "[a]lthough the RDF allows the utilities to state their preference for one of the three discount rates, its language does not provide for outright choice" when it comes to ratepayer funding for any risk-based decisions.[194] As explained by the Joint IOUs, BCRs developed within the RDF are "used to assess and rank risks and mitigations within utility specific RAMP [Risk Assessment and Mitigation Phase] and GRC [General Rate Case] filings."[195] However, RAMP and general rate case filings evaluate mitigations at the program level, rather than the project level; and moreover, the utility's "preferred" discount-rate scenario is one input that parties may contest within those proceedings before the Commission arrives at any decision. By contrast, here, in the SB 884 program context, we make two observations: (1) first, a single, common discount rate must be chosen, at the very latest, by the time the Commission issues its Phase 2 Application decision and thereby finalizes the

[193] Cal Advocates August 7, 2026 Opening Brief at 18; EPUC August 7, 2026 Opening Brief at 22-23; TURN March 13, 2026 Protest at 5.

[194] Cal Advocates June 9, 2026 Opening Comments at 48-49.

[195] Joint IOUs August 7, 2026 Opening Brief at 26.

Phase 2 Conditions (as the discount-rate will directly impact any BCR threshold that is tied to any Phase 2 Condition),[196] and (2) second, we find that choosing this common discount rate now, as opposed to after any large electrical corporation submits its Phase 2 Application with the Commission, will significantly facilitate the Commission's ability to resolve any future, expedited Phase 2 Application proceeding within the nine-month statutory timeline. Moreover, due to the fact that a BCR-related threshold has already been established for the Phase 2 Application stage (wherein all BCRs of submitted projects must be greater than or equal to 1), were the Commission *not* to choose a common discount rate in this proceeding, then any large electrical corporation participating in SB 884 program would, in effect, when submitting its Phase 2 Application, be submitting up to three distinct EUPs. Under the Joint IOUs' proposal, each project would carry three BCRs in the Phase 2 Application, one for each RDF discount rate scenario, and the utility would choose which of the three determines whether the project proceeds. That would either leave the decisional metric to utility discretion (rather than a Commission-adopted methodology) or the Commission would need to resolve the issue during a Phase 2 Application proceeding.

Finally, the Commission finds the appropriate common discount rate to apply to the SB 884 program is the WACC rate, as we agree with EPUC that ratepayers both bear the costs and receive the benefits of undergrounding.[197] The

[196] This not to mention that the discount rate will also impact which projects can be submitted in any Phase 2 Application.

[197] EPUC August 7, 2026 Opening Brief at 22-23.

Commission finds that the record supports this premise: ratepayers pay utility revenue requirements through rates rather than direct costs, and for capital undergrounding projects the revenue requirement substantially exceeds direct costs because it includes the authorized return on debt and equity, taxes, and other loaders.[198] PG&E already reflects this, discounting capital costs at its Commission-approved after-tax WACC because that approach "aligns with PG&E's cost-of-service ratemaking framework."[199] Where, as here, the BCR operates as a gating condition on project submission and cost recovery from ratepayers, the analysis should be conducted at the rate ratepayers in fact bear. As such, the Commission directs the large electrical corporations to the use of the WACC rate for all BCRs presented to the Commission, at any point, in connection with the SB 884 program. The Commission also finds, as proposed by TURN, that using a single discount rate for both numerator and denominator is appropriate in the SB 884 program context to avoid biasing the BCR.[200] For the avoidance of doubt, these requirements will apply to all BCRs presented to the Commission at any point in connection with the SB 884 program.

5.5. Backcasting

In D.25-08-032 (Phase 4 RDF Decision), the Commission directed the utilities to provide as follows regarding backcasting:

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[198] TURN June 9, 2026 Comments at 6-7, EPUC August 7, 2026 Opening Brief at 8.

[199] TURN June 9, 2026 Opening Comments, Attachment at Joint IOU Response to TURN Data Request (SPD-37-JointIOU-PhI_DR_TURN_001), Answer 004, at 9-10. The same response reflects divergent practice: SCE will not provide PVRR calculations for the EUP, and SDG&E relies on direct project costs.

[200] TURN June 9, 2026 Opening Comments at 7-8.

> "Once the level of granularity of an RRU [Risk Reporting Unit][201] for each risk is established, beginning with SCE's 2026 RAMP and Sempra Companies' 2028 general rate case filings, that level of granularity for the RRU should be maintained for all future filings which include that risk. If a utility wishes to update an RRU's level of granularity it must clearly explain the method it chose to update the granularity and how the granularity of the new RRU differs from the granularity of the prior RRU. Additionally, the utility must provide a backcast of post-mitigated risk, risk reduction and Benefit-Cost Ratios submitted to the previous cycles of RAMPs [Risk Assessment and Mitigation Phase] and GRCs [General Rate Cases] that are impacted by an update to the RRU's level of granularity."[202]

In Resolution SPD-37, the Commission found that to build upon recently issued guidance issued by the *Energy Safety EUP Guidelines*, it would recommend that the utilities further address the concept of backcasting in this proceeding,

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[201] The Commission does not adopt a definition of Risk Reporting Unit (RRU) in either Resolution SPD-15 or Resolution SPD-37. Resolution SPD-37 does refer to background information about the RRU. The Commission in Resolution SPD-37 at 26 (fn. 172) refers to a Staff Proposal prepared during R.20-07-013, Phase 4 Workshop 1, *SPD Staff Proposal on Definition of Scoped Work and the Risk Reporting Unit, November 8, 2024*. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M545/K343/545343783.PDF. In addition, the Staff proposes a definition as part of its updated Appendix 1: *SB 884 Project List Data Requirements Guidelines (July 24, 2025)* at A1-4. Appendix 1 is an attachment to Attachment A of Resolution SPD-37: "Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operation or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk. The RRU must include common elements that must include, but are not limited to Consequence Attributes, Risk level, line-item costs, benefit-cost ratios (CBRs), work units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to, hierarchy, scenario, version, risk event, tranche, and mitigation type." (Footnotes in original omitted.)

[202] D.25-08-032 (Phase 4 RDF Decision) at 68 and Appendix A at A-16, Row 15.1 "Define the Mitigation Risk Reporting Unit."

stating that the Joint IOUs' BCR proposal should incorporate a proposal for backcasting, as follows:

> "The large electrical corporations' proposal for the CBR calculation shall detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications…It shall complement the *SB 884 Project List Data Requirements Guidelines* by outlining how to calculate the CBR for the purposes of EUPs and provide more information on the calculation's key components. These key components of at least one proposed methodology shall, at a minimum, include:…**Backcasting**, a method for recalculating CBRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an 'apples-to-apples' comparison should be proposed."[203]

The Commission further stated: "[The Commission] finds that the requirement for backcasting is reasonable and allows for greater alignment with the *Energy Safety EUP Guidelines*. The electrical corporations shall include guidance on backcasting in any CBR methodology proposal."[204]

The Joint IOUs recommend that the Commission adopt a single definition of backcasting for the utilities to use in the SB 884 program. The Joint IOUs state that the RDF proceeding, Resolution SPD-37, and the *Energy Safety EUP Guidelines* all require some type of backcasting.[205]

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[203] Resolution SPD-37 at 26-27 (bold in original).

[204] Resolution SPD-37 at 28.

[205] Joint IOUs Application at 14-15. Energy Safety uses the term "backtesting" rather than backcasting in the *Energy Safety EUP Guidelines*.

The Joint IOUs state that the definitions and requirements for backcasting among the three documents are slightly different. According to the Joint IOUs, backcasting is presented as follows:[206]

> "The RDF requires using updated inputs (e.g., new RRUs [Risk Reporting Units], new risk models) to recalculate BCRs, "pre-mitigated risk, post-mitigated risk, or other data" required by the RDF in order "to establish a bridge between prior inputs and the new inputs, [to] ensure an "apples-to-apples" comparison." [207]

> "Resolution SPD-37 defines backcasting as "a method for recalculating [BCRs] and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an 'apples-to-apples' comparison…."[208]

> "The Energy Safety EUP Guidelines definition of backtesting states, "If the Large Electrical Corporation changes its Risk Modeling Methodology in a way that triggers a versioning update, it must backtest the new models using historical data back to the start of the EUP. These backtests must include a Project-Level analysis of each Confirmed Project that passed through Screen 3 (Project Risk Analysis) in that time."[209]

The Joint IOUs recommend adopting the definition from the *Energy Safety EUP Guidelines* because this definition, they argue, better accommodates the

[206] Joint IOUs Application at 14-15.

[207] Joint IOUs Application at 14 and fn. 33, *citing* D.25-08-032 (Phase 4 RDF Decision), Appendix A at A-3.

[208] Joint IOUs Application at 14 and fn. 34, *citing* Resolution SPD-37 at 27.

[209] Joint IOUs Application at 15 and fn. 35, *citing Energy Safety EUP Guidelines* at 52, Section 2.8.5.3.

utility's ability to select projects at the circuit segment level, as consistent with the *Energy Safety EUP Guidelines*.[210] The Joint IOUs suggest it is reasonable to conduct backcasting/backtesting at the same level of detail as Energy Safety.[211] According to the Joint IOUs, conducting backcasting at a subproject or RRU level as contemplated by the RDF (R.20-07-013) and Resolution SPD-37 would introduce misalignment between project selection at the circuit segment level and recalculations required when a utility introduces a new risk model if it were to be conducted at the RRU or subproject level.[212]

The Staff BCR White Paper does not directly address backcasting. Cal Advocates, TURN, MGRA, and Communications Providers do not address backcasting.

EPUC states that the Commission should require comprehensive backcasting for undergrounding projects consistent and reject the Joint IOUs' proposal to limit backcasting to circumstances involving sporadic and utility-determined "substantive" risk model updates.[213] According to EPUC, backcasting provides an "apples-to-apples comparison between original and updated project evaluations and is critical to assessing changes in project cost-effectiveness over time."[214] EPUC concludes that, "[c]onditioning backcasting on subjective utility determinations would reduce transparency, hinder meaningful

[210] Joint IOUs Application at 15.

[211] Joint IOUs Application at 15.

[212] Joint IOUs Application at 15.

[213] EPUC August 7, 2026 Opening Brief at 23-24.

[214] EPUC August 7, 2026 Opening Brief at p. (v.) and 23-24.

comparisons, and weaken the Commission's ability to evaluate whether projects continue to provide the best value to ratepayers."[215]

In response to these recommendations, the Joint IOUs reiterate the need to adopt a single definition of backcasting and recommend the definition relied upon by Energy Safety.[216] The Joint IOUs state backtesting should only be performed at the same level of detail as the original analysis.[217] Thus, if a BCR was calculated for a project chosen at the circuit segment level, any future backtesting for that project should only be performed at the circuit segment level to avoid misalignment between comparisons.[218]

The Commission finds it reasonable to retain the Resolution SPD-37 definition of backcasting, recalculating BCRs, and unit costs using updated RRU structures and risk model inputs, and require that backcasting be performed at the RRU or subproject level, consistent with the RDF (R.20-07-013). Consistent with the RDF, the Commission finds that backcasting should also recalculate pre-mitigated risk, post-mitigated risk, and total mitigation benefit, as well as the O&M Costs and O&M Savings underlying the BCR, so that both sides of the BCR are restated on the new reporting unit. If the utility elects the Subproject Designation later during implementation, the new reporting unit (i.e., the RRU or subproject) may differ materially in size, cost, and risk from the reporting unit (i.e., the project) reported in the SB 884 application with the 10-year electric

[215] EPUC August 7, 2026 Opening Brief at p. (v.) and 23-24.

[216] Joint IOUs August 7, 2026 Opening Brief at 14-15.

[217] Joint IOUs August 7, 2026 Opening Brief at 14-15.

[218] Joint IOUs August 7, 2026 Opening Brief at 15.

underground plan. Or, to put this another way, given that significant changes can be made to the forecasted economic metrics of an undergrounding project as it is more accurately scoped,[219] if the utility, after running any less-than-fully-scoped "projects" (the ones it first disclosed to the Commission during its Phase 2 Application) through any further filters and screens established by Energy Safety, later decides, after looking at any project's full scope, to only implement a portion of such project (i.e., an RRU or subproject, e.g., only a portion of previously scoped circuit), then the economics and cost-efficiency of such portion may differ materially from what was originally forecast during Phase 2 Application proceeding. Projects enter an *EUP at the Energy Safety EUP Guidelines* at Screen 2 on the basis of preliminary scoping, and their cost and risk estimates change as detailed engineering is completed. Without backcasting, as adopted by the Commission herein, a change in the reported BCR (i.e., where the actual BCR of a project differs from its Phase 2 Application proceeding forecast BCR) could reflect either (i) a genuine change in project scope, cost, or risk, or (ii) merely a change in how the project was subdivided or modeled. Without backcasting as adopted herein, the Commission and parties would be unable to tell what drove the change in the BCR from forecast to actual. Backcasting as adopted herein, isolates the former reflection (i), by restating prior values as they would have been calculated had the new structure and inputs been used at the time of the Phase 2 Application. Since the Phase 2 Conditions for balancing account treatment necessitate comparisons between actual, recorded BCRs and original,

[219] Joint IOU Application at 31–32

forecasted BCRs, we need to create a means for a granular apples-to-apples comparison. Adopting the Joint IOUs proposal to only backcast at the same level of detail as the original analysis would not allow for this.

In their comments on the Proposed Decision, the Joint IOUs argue that the backcasting requirements adopted herein conflict with the Energy Safety EUP Guidelines and the additional Phase 2 Conditions adopted in this decision. We find no error on this basis. The purpose of the backcasting requirement adopted herein is not to recreate or reevaluate the original project-selection decision made under the Energy Safety EUP Guidelines. Rather, its purpose is to create an apples-to-apples comparison between forecasted and actual values for purposes of evaluating BCRs, unit costs, and compliance with Commission-adopted Phase 2 Conditions.

The Joint IOUs support backcasting at the circuit-segment level at which projects are selected.[220] But the Phase 2 Conditions are applied, and actual costs and benefits are recorded and audited, at the project level: the RRU, or the Subproject where a large electrical corporation elects the Subproject Designation. A forecast restated at a level different from the one at which actuals are recorded would not produce the comparison those conditions require. Moreover, backcasting below the level at which a project was initially evaluated arises only where the large electrical corporation elects the Subproject Designation. Where project scope, reporting structures, or risk models change over time, comparisons

[220] Joint IOU Application at 14–15; Resolution SPD-37 at 28; see also Joint IOUs November 5, 2026 Opening Comments on the Proposed Decision at 11.

between forecasted and actual results cannot be meaningfully evaluated unless prior values are restated on a comparable basis.

The Joint IOUs also argue that the use of updated risk model inputs creates cost-recovery uncertainty because previously forecasted BCRs may change when recalculated. We disagree. Backcasting addresses this concern rather than creating it. Because the forecast is restated using the same risk model and inputs used to calculate actual values, a model change affects both the forecasted and actual values, so the comparison between them reflects changes in project performance rather than the model change itself. Restating values on the current model, rather than freezing them on the model in use at project selection, is also consistent with the requirement that actual benefits be calculated using the risk model version in effect at the time of the audit, and with the Energy Safety EUP Guidelines' requirement to backtest when a risk model version changes.[221] The purpose of backcasting is not to reevaluate whether a project should originally have been selected. Rather, it is to isolate the effects of changes in project performance from changes in reporting structures, model inputs, or other methodological changes. Without backcasting, the Commission would be unable to determine whether differences between forecasted and actual BCRs or unit costs reflect actual project performance or merely changes in the methods used to calculate those values.

Backcasting is intended to identify and reconcile the effects of changes in project scope, reporting structure, risk models, and model inputs. Backcasting

[221] See COL 59; Energy Safety EUP Guidelines § 2.8.5.3 at 52.

restates the forecast on the current reporting structure and risk model; it does not change the applicable Phase 2 Condition or its threshold. A change in a risk model or model input occurring after a project has entered construction, standing alone, shall not establish noncompliance with a Phase 2 Condition. [222] Where a large electrical corporation contends that a difference between forecasted and actual values is attributable to such a change in a risk model or model input, it bears the burden of demonstrating that effect, including by reporting, for comparison purposes only, the actual BCR calculated under the risk model version underlying the Screen 4 forecast.

Finally, we agree with EPUC that an apples-to-apples comparison between original and updated project evaluations is critical to assessing changes in project cost-effectiveness over time; and that "[c]onditioning backcasting on subjective utility determinations would reduce transparency, hinder meaningful comparisons, and weaken the Commission's ability to evaluate whether projects continue to provide the best value to ratepayers,"[223] in contradiction to the directive in Resolution SPD-37 to promote "comparability, transparency, and traceability in BCR calculations across large electrical corporations."[224]

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[222] See Joint IOU Application at 15 (proposing to backcast only upon "substantive updates" to risk models); EPUC Opening Brief at 23–24 (opposing backcasting contingent on utility determinations); See Joint IOUs November 5, 2026 Opening Comments on the Proposed Decision at 11 (arguing that updated risk inputs would change BCRs post hoc and render previously cost-effective projects unrecoverable)

[223] EPUC August 7, 2026, Opening Brief at p. (v.) and 23-24.

[224] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5.

5.6. Net Salvage Values

Net Salvage value means the salvage value of an electrical infrastructure related asset that has been retired less the cost of removal of that asset.[225]

The RDF proceeding (R.20-07-013) did not address Net Salvage values.

Resolution SPD-15 does not address the use of Salvage Values as a component of the BCR.

In Resolution SPD-37, the Commission stated that the Joint IOU proposal on Total Capital Costs and the BCR should address "[t]he relationship between Total Capital Costs and other categories, such as Operating and Maintenance (O&M) Costs, O&M Savings, or **Net Salvage values**, …."[226]

The Joint IOUs propose not adding net salvage values as a stand-alone element to the BCR requirements in this proceeding and state that the RDF does not require utilities to include net salvage values as a stand-alone component in a BCR calculation.[227] The Joint IOUs state that salvage values are addressed by the utilities in different ways, through existing cost-recovery and accounting practices. For example, PG&E relies on "group accounting," which studies all its distribution assets to develop depreciation rates as opposed to individual assets in separate filings. [228] The Joint IOUs state that:

> "In group accounting, all units having like mortality characteristics or all units of an account are considered together. Accruals for the

[225] Resolution SPD-37 at 26 (fn. 69).

[226] Resolution SPD-37 at 26 and Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 5-6 (footnote in original omitted and emphasis added).

[227] Joint IOUs Application at 15.

[228] Joint IOUs Application at 15.

> group are based on composite or weighted average values of salvage and service life expectancy. The resulting values are applied to the surviving plant balances each year or each accounting period. A deficiency due to early retirement of a particular unit is made up through other accruals on a unit which outlives the average. … Because of greater simplicity in maintaining records, the group basis is more feasible for most 'classes of utility property' where large numbers of units are involved. It is the more generally used among electric gas, telephone, and water utilities."[229]

The Staff BCR White Paper and MGRA do not directly address net salvage value as a component of the BCR. However, EPUC, Cal Advocates, and TURN oppose omitting net salvage value from the BCR calculation.[230] Cal Advocates suggests that the Commission require the Joint IOUs to incorporate all costs, both direct and indirect (including taxes, rate of return, net salvage values) incurred by undergrounding projects into their BCR calculations, be it via PVRR multipliers or some other method.[231]

The Commission finds that net salvage value should be accounted for at the project level as part of the PVRR cost treatment expressed as the Cost element in the BCR. This finding is reasonable because omitting net salvage from costs will lead to an underestimate of project costs, inflating the BCR. The Commission also finds that, in the absence of the use of net salvage value, electric

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[229] Joint IOUs Application at 16 and fn. 37, *citing* CPUC, Water Division, *Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals* at 8.

[230] EPUC August 7, 2026 Opening Brief at 21-22 Cal Advocates June 9, 2026 Opening Comments at 11; and TURN June 9, 2026 Opening Comments at 7.

[231] Cal Advocates June 9, 2026 Opening Comments at 9-11 and 50-54.

undergrounding could result in the abandonment of infrastructure, such as old poles, which would become "stranded costs" borne by other parties rather than the utilities.[232] In short, only including direct project costs is not sufficient since projects also include indirect costs. These indirect costs include end-of-life costs represented by net salvage value and the true costs of undergrounding projects can only be captured through the inclusion of indirect costs in the BCR calculation and that net salvage value should be part of that calculation. Net salvage shall be reflected once, and only once, in the PVRR used as the Cost element of the BCR. If net salvage or removal costs are already reflected in the project's PVRR (*e.g.*, through a large electrical corporation's depreciation rates, group-accounting treatment, PVRR multiplier, or another component of its PVRR calculation), the large electrical corporation shall identify and quantify that treatment to the extent reasonably practicable and shall not separately add the same costs. If the PVRR does not otherwise reflect net salvage, the large electrical corporation shall include a reasonable estimate based on the best available information.

5.7. Present Value Revenue Requirement

Present Value Revenue Requirement (PVRR) is a financial metric used by utilities in rate cases and long-term planning to evaluate the cost of investments or programs over the life of the asset. The revenue requirement is the full cost to be funded by ratepayers. Providing a PVRR is currently optional under the *SB*

[232] EPUC March 16, 2026 Protest at 7; Cal Advocates June 9, 2026 Opening Comments at 51–53; TURN June 9, 2026 Opening Comments at 7.

884 Project List Data Requirements Guidelines. PVRR includes all project costs such as the capital investment, incremental O&M and net salvage value. O&M Savings are not included in the PVRR; they are reflected in the BCR numerator. PVRR is calculated by adding up the costs for each year of the project, determining the revenue required to compensate for the costs, and then discounting back to the BCR year zero.[233]

TURN addresses the PVRR. Specifically, TURN believes that PVRR should be used to represent costs in the denominator of the BCR calculation.[234] TURN believes that this will more accurately reflect the true cost of mitigation as opposed to capital costs only.[235] When calculating PVRR, TURN also recommends applying a discount rate to the PVRR and omitting inflation. They argue that this will avoid overestimating PVRR.[236]

The Commission finds it reasonable to require the utilities to use the PVRR for BCR calculations. The PVRR shall reflect the full revenue requirement associated with the project, including net salvage, but shall not include any net salvage or removal cost more than once. If net salvage or removal costs are already reflected in the project's PVRR (*e.g.*, through a large electrical corporation's depreciation rates, group-accounting treatment, PVRR multiplier, or another component of the PVRR), the utility shall identify and quantify that

[233] Resolution SPD-37, CPUC Guidelines, Table 5, at A1-29; see also TURN Counterproposal and Comments at 6; Cal Advocates June 9, 2026 Opening Comments at 51–52.

[234] TURN June 9, 2026 Opening Comments at 16.

[235] TURN June 9, 2026 Opening Comments at 6.

[236] TURN June 9, 2026 Opening Comments at 1.

treatment to the extent reasonably practicable and shall not separately add the same costs. If the PVRR does not otherwise reflect net salvage, the utility shall include a reasonable estimate based on the best available information. The PVRR constitutes the Cost element (Capital Costs and O&M Costs) of the BCR. If utilities do not have a PVRR for the mitigation project, the utilities are required to make a best estimate using available data.

5.8. Definition of BCR Year Zero

For the purpose of the proceeding, the Commission in Resolution SPD-37 requested that parties address whether to define BCR Year Zero as follows: the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits.[237] Resolution SPD-15 did not address the issue.[238] The Commission did not address this issue in the RDF proceeding (R.20-07-013).

In responding to the Commission's request above, the Joint IOUs recommend against the above definition proposed in Resolution SPD-37.[239] Instead, the Joint IOUs recommend that BCR Year Zero be defined as the year that a utility's 10-year electric undergrounding plan becomes effective.[240] The

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[237] Resolution SPD-37 at 27 (quotes in the original) and Attachment A, *SB 884 Program Guidelines (Dec. 10, 2025*) at 6 and A1-15 Table 1 Data Set: "The year the risk and costs for Undergrounding_Alternative_Mitigations program for the RRU [Risk Reporting Unit] (or Project) are discounted to."

[238] For purposes of the SB 884 process, the *SB 884 Project List Data Requirements Guidelines* at 15 define the term "used and useful" as: "Used and useful means to be fully complete and providing service to customers."

[239] Joint IOUs Application at 16.

[240] Joint IOUs Application at 16.

Joint IOUs explain that this date would be the year a utility begins recording project costs to the balancing account.[241] For example, the Joint IOUs explain, if a utility's SB 884 application is approved by October 31, 2027, and the utility begins recording costs to its balancing account on January 1, 2028, the effective date of the utility's 10-year electric undergrounding plan is 2028 – and BCR Year Zero is permanently set at 2028.[242] The Joint IOUs state that defining BCR Year Zero as a single year—the year a utility's 10-year electric undergrounding plan becomes effective as evidence by costs recorded in the balancing account —ensures consistency when comparing the BCRs for all the projects in a utility's portfolio.[243] In contrast, the Joint IOUs state that, requiring utilities to have a different BCR Year Zero for every project and every subproject based on operative year, referring to the concept of "used and useful" in Resolution SPD-37, would make comparison, prioritization, and aggregation of BCRs inconsistent.[244] In this respect, the Joint IOUs state that establishing the approval year of the 10-year electric undergrounding plan as BCR Year Zero is reasonable and consistent with how utilities forecast costs in their general rate cases where all costs are based on a test year forecast that does not change and all cost analyses are anchored to the test year values.[245]

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[241] Joint IOUs Application at 16 (fn. 39).

[242] Joint IOUs Application at 16 (fn. 39).

[243] Joint IOUs Application at 16.

[244] Joint IOUs Application at 16.

[245] Joint IOUs Application at 16.

The Staff BCR White Paper did not address this issue. Cal Advocates, MGRA, and Communications Providers do not address this issue.

TURN supports the Joint IOUs' position, with qualifications, stating "[i]t is difficult to tell based on this language exactly how this calculation will be accomplished, but it may not be problematic as long as 1) costs are the present value of revenue requirement (discussed above) and 2) all dollars are nominal and therefore include inflation and other expected cost increases for future projects. These values can then be discounted from nominal dollars."[246]

EPUC disagrees with the position of the Joint IOUs. According to EPUC, "[t]he relevant question is not whether a common reference year would simplify comparisons across projects, but whether the BCR accurately reflects the costs and benefits of each project from a ratepayer perspective." EPUC states that the Commission's objective must be to ensure that each project's BCR accurately reflects the timing of its costs and benefits.[247] EPUC's concern is that "[b]y replacing the Commission-approved definition with a portfolio-wide reference year, the IOUs would decouple the discounting analysis from the point at which project benefits actually begin to accrue, undermining the very purpose of BCR Year Zero."[248]

The Commission adopts the Resolution SPD-37 definition of BCR Year Zero as the year a project becomes "used and useful," the single, project-specific

[246] TURN June 9, 2026 Opening Comments at 7; TURN August 7, 2026 Opening Brief at 10-11.

[247] EPUC August 7, 2026 Opening Brief at 26.

[248] EPUC August 7, 2026 Opening Brief at 26.

reference year to which all of that project's costs and benefits are discounted. In Resolution SPD-37, the Commission adopted the "used and useful" definition through the Technical Working Group process and recorded that all stakeholders, including the Joint IOUs and TURN, unanimously agreed to it, directing that the definition be included in the utilities' BCR methodology proposal.[249]

This Commission finding is reasonable because the Joint IOUs' single effective-year alternative would defeat the very purpose of the metric. The timing effect the Joint IOUs seek to remove is precisely what the BCR should capture. Anchoring every project to a common early effective-year discounts costs and benefits to a date that may precede a project's actual in-service by years, so that projects delivering benefits on very different schedules are scored as if they delivered them at the same time. For a project with a delayed in-service date, its capital costs are compounded (inflated) forward over a longer horizon to reach the early anchor, inflating the present-value denominator, while its benefits, which do not begin until the later in-service date, are discounted back over that same longer horizon. A used-and-useful anchor, by contrast, ties each project's discounting to the year it actually begins delivering benefits, preserving the schedule differences that distinguish a fast project from a slow one. Flattening those differences to an administratively convenient year strips the BCR of its value as a prioritization tool.

[249] Resolution SPD-37 at 6 and 27 & fn. 72 (*citing* PG&E Responses to Post-Workshop Questions, Apr. 25, 2025, at 19; TURN Responses to Post-Workshop Questions, Apr. 25, 2025, at 29).

5.9. Baseline Scenario for Reference Conditions to Compare BCR

In the context of a BCR, the Baseline Scenario represents "the reference conditions against which all benefits and costs are measured."[250]

Resolution SPD-15 does not address the concept of Baseline Scenarios.

In Resolution SPD-37, the Commission stated that the Joint IOU proposal should include "O&M Savings, defined as the avoided O&M expenditures eliminated by the proposed project as compared to the **No-Build Baseline**."[251] The Commission explained that "No-Build Baseline" represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU) implementation."[252] In contrast, the Commission stated that "[t]he Build Baseline is used to compare the relative costs and benefits of various design or implementation alternatives."[253]

The Staff BCR White Paper recommends the Commission adopt a specific Baseline Scenario to promote consistency and recommends the Baseline Scenario referred to as the No-Build Baseline Scenario.[254] The Staff BCR White Paper describes the No-Build Baseline Scenario, in part, as follows:

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[250] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 14 and fn. 59, *citing* L. B. Mohr, *Impact Analysis for Program Evaluation*, 2nd. Edition, 1995.

[251] Resolution SPD-37 at 26 and fn. 70 (emphasis added).

[252] Resolution SPD-37 at 26 (fn. 70).

[253] Resolution SPD-37 at 26 (fn. 70).

[254] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 15.

> "The No-Build Baseline establishes the current risk profile of the system, incorporating all infrastructure and risk controls that are already funded, approved, or implemented (e.g., existing VM [Vegetation Management] and inspection cycles). This baseline serves as the calibrated reference point for determining the marginal (i.e., incremental) value of any single new investment.
>
> In this baseline scenario, the BCR quantifies the incremental benefit of a specific new mitigation given the presence of the existing controls (i.e., No-Build Baseline). By accounting for the benefits of the existing programs into the baseline, Scenario 2 ensures that the new mitigation is only credited for the additional risk reduction it provides beyond what is already achieved."[255]

Similarly, the Joint IOUs and some of the parties agree that the baseline scenario for the BCR should be the No-Build Baseline Scenario. The Joint IOUs agree with Staff that consistent baseline treatment and clear identification of individual components are foundational to a robust BCR framework.[256] The Joint IOUs, however, differ with some parties on whether mitigations, such as EPSS and PSPS, should be reflected in the No-Build Baseline.

Cal Advocates supports including all mitigations in the baseline, stating that "[t]he benefits of a mitigation (i.e., the risk reduction) is a function of the baseline to which the mitigation is compared."[257] According to Cal Advocates, the Commission should require the Joint IOUs to use a Baseline Scenario that include all existing mitigations, which may vary based on the utility and the

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[255] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 15.

[256] Joint IOUs June 9, 2026 Opening Comments at 16.

[257] Cal Advocates June 9, 2026 Opening Comments at 49.

location.[258] Cal Advocates proposes that "[t]he baseline used to measure the impacts of mitigations should represent real-world conditions" and recommends including in any baseline all existing mitigations, such as EPSS and PSPS.[259] For these reasons, Cal Advocates recommends that "[f]or the calculation of BCRs, the Joint IOUs should be required to use a baseline scenario that includes all existing mitigations. While this may vary based on utility and location, it is reasonable to expect a baseline to consist of bare overhead wire, PSPS, fast-trip programs, and current O&M and vegetation management programs."[260]

TURN recommends the Non-Build Baseline and that the Commission require the utilities to explicitly report the O&M expenses for the No-Build Baseline, the avoided O&M costs (O&M Savings) resulting from displacing existing activities, and the new incremental O&M Costs introduced by the mitigation itself.[261]

The Joint IOUs do not support including all mitigations in the Non-Build Baseline. For example, the Joint IOUs state: "Assuming EPSS in the baseline would remove a key distinguishing element of that mitigation alternative and complicate the ability to measure the incremental benefits and disbenefits associated with its deployment. Therefore, to maintain consistency with Energy Safety guidance and to support a clear, mitigation-neutral comparison, EPSS

[258] Cal Advocates June 9, 2026 Opening Comments at 9 and 49.

[259] Cal Advocates June 9, 2026 Opening Comments at 9 and 49.

[260] Cal Advocates June 9, 2026, Opening Comments at 50.

[261] TURN June 9, 2026, Opening Comments at 18.

must be evaluated as part of the mitigation alternatives rather than assumed in the baseline."[262]

The Commission adopts the No-Build Baseline as a single, well-defined reference condition and requires that every component of the BCR be measured against it. The No-Build Baseline should be defined as the status quo of the existing system, the expected conditions in the absence of any new project or RRU, incorporating all infrastructure, mitigations, and risk controls that are already funded, approved, or implemented (e.g., current O&M, vegetation management and inspection cycles, PSPS, EPSS and fast-trip programs).

In the context of the use and application of a BCR, all four components must be calculated against a common baseline, both to ensure an accurate and comparable BCR result, and to remain consistent with the RDF (R.20-07-013), which itself measures risk reduction against a defined Baseline. The RDF (R.20-07-013) defines "Baseline Risk" as the residual risk evaluated at the Baseline "after taking into account all risk reduction Benefits from all risk mitigation activities projected to have been performed by the start of the new GRC [General Rate Case] cycle," including those classified as Controls.[263] In BCR terms, the Baseline Scenario is "the reference condition against which all benefits and costs are measured."[264]

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[262] Joint IOUs July 7, 2026, Reply Comments at 35.

[263] D.25-08-032 (Phase 4 RDF Decision) Appendix A at A-3.

[264] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 14 and fn. 59.

Resolution SPD-37 itself specifies such a baseline: the "No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU) implementation."[265] Building on that definition, the Staff BCR White Paper recommends that the Commission adopt the No-Build Baseline as the single, uniform, and most comprehensive reference against which all four components are calculated, to promote consistency across projects and utilities. The Staff BCR White Paper describes the No-Build Baseline Scenario, in part, as follows: "The No-Build Baseline establishes the current risk profile of the system, incorporating all infrastructure and risk controls that are already funded, approved, or implemented (e.g., existing VM [Vegetation Management] and inspection cycles). This baseline serves as the calibrated reference point for determining the marginal (i.e., incremental) value of any single new investment."[266]

In this baseline scenario, the BCR quantifies the incremental benefit of a specific new mitigation given the presence of the existing controls (i.e., No-Build Baseline). By accounting for the benefits of the existing programs into the baseline, this ensures that the new mitigation is only credited for the additional risk reduction it provides beyond what is already achieved.[267]

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[265] Resolution SPD-37 at 26, fn. 70.

[266] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 15.

[267] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) Attachment, *Staff BCR White Paper* at 15 (§ 4.3).

Finally, for the avoidance of doubt, all decisions made in this Section 5 will apply to all BCRs presented to the Commission at any point in connection with the SB 884 program.

6. Audit - Audit of Costs Recorded to Balancing Account

Within the SB 884 program, if, after reviewing a Phase 2 Application, the Commission decides to conditionally approve any EUP costs, the large electrical corporation will then establish a one-way balancing account wherein it may record and recover any conditionally approved costs, but only so long as such costs meet the program's Phase 2 Conditions. Resolution SPD-15 established the concept of Phase 2 Conditions to protect ratepayers from unexpected and inefficient cost overruns during the 10-year term of the program. In connection therewith, Resolution SPD-15 also established an initial framework for periodic audits of costs recorded in the balancing account, stating:

> "[P]eriodic audits of the established balancing account will be performed to ensure that costs booked [by the IOU] to the one-way balancing account meet the Phase 2 Conditions. If the audit [of the balancing account under the Phase 2 Conditions] demonstrates that costs were incorrectly recorded or failed to meet the Phase 2 Conditions, the Commission may order a refund. The details of this audit, including but not limited to who will perform it, content, frequency, venue, method for true-up and refund mechanism will be determined in a future decision or order."[268]

On April 8, 2025, Commission Staff held a Technical Working Group which included further details about the audit process.[269] Following the

[268] Resolution SPD-15 at 15.

[269] Resolution SPD-37 at 18.

Technical Working Group, Staff sought additional feedback via written responses questions to stakeholders.[270] Parties offered written responses to questions by Staff. These responses have been incorporated into the record of this proceeding.[271]

Subsequently, in Resolution SPD-37, the Commission established both (i) the cadence of the audit, stating it shall "occur annually," and "result in an audit report that will be filed and served to the Phase 2 Application docket within five days of its completion and approval"[272] and (ii) established what it referred to as the "Primary" and "Secondary" objectives of the audit.[273]According to Resolution SPD-37 (and in alignment with the initial directive in Resolution SPD-15), the "Primary Objective" of the SB 884 program audit is to determine, after costs are recorded to the balancing account, whether such costs do, in fact, meet the Phase 2 Conditions.[274] At the time of Resolution SPD-37's issuance, the Commission had established five Phase 2 Conditions, as follows:[275]

> (1) total annual costs for each year of the 10-year program must not exceed an annual cost cap (such cap to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #1);

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[270] Resolution SPD-37 at 18, *citing* Responses to Staff Questions after April 2025 Workshop.

[271] ALJ Ruling *Email Ruling Entering Documents into Record* (June 5, 2026).

[272] Resolution SPD-37 at 23.

[273] Resolution SPD-37 at 22, 23, and 29.

[274] Resolution SPD-37 at 34, Finding of Fact 23.

[275] Resolution SPD-15, Attachment 1, *Senate Bill (SB) 884 Program: CPUC Guidelines* at 11.

(2) all third-party funding obtained throughout the duration of the program shall be applied to reduce any established cost cap for the year in which the third-party funding is obtained (Phase 2 Condition #2);

(3) the average, actual unit costs for all projects completed in any given two-year period must not exceed some approved average unit cost (such unit cost to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #3);

(4) the average, actual BCR for all projects completed in any given two-year period must not fall below some approved average BCR (such BCR to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #4); and

(5) any further conditions (to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #5).

As for the Secondary Objectives of the audit, they are: (1) verifying project costs recorded to the balancing account tie to projects that are used and useful (herein, the Used and Useful Requirement); and (2) verifying the incrementality showing found in Application Requirement No. 2, i.e., that recorded costs in the balancing account do not duplicate any costs already authorized by another Commission decision, mechanism, or those received from a third party (herein, the Incrementality Requirement).[276]

Resolution SPD-37 directed the Joint IOUs to include, in the instant Application, a detailed description of a proposed methodology that establishes

[276] Resolution SPD-37 at 28-29.

how the auditor will validate whether the large electrical corporation has satisfied the "Primary" and "Secondary" objectives of the audit.

Given the fact that "Phase 2 Condition #5" as described above refers to any additional Phase 2 Conditions that the Commission may later establish during Phase 2 Application proceeding, i.e., Phase 2 Condition #5 remains undefined), when the Commission specified, in Resolution SPD-37, that the instant Application should address the SB 884 program's "Primary Objective" (i.e., how costs meet the Phase 2 Conditions), the Commission only mentioned Phase 2 Conditions #1 through #4, stating the instant Application must include an approach for:

> "(a) verifying that the total annual costs did not exceed the approved cost cap for a given year of the EUP ([Phase 2] Condition #1); (b) verifying that any third-party funding obtained was applied to reduce the established cost cap for the specific year in which the third-party funding was obtained ([Phase 2] Condition #2); (c) determining that the average recorded unit cost for all projects completed in any given two-year period did not exceed the approved average unit cost cap ([Phase 2] Condition #3); (d) determining that the average recorded CBR [BCR] for all projects completed in any given two-year period equals or exceeds the approved threshold CBR [BCR] value. ([Phase 2] Condition #4)."[277]

Within this context, the Assigned Commissioner's Scoping Memo included the following issue for consideration in this proceeding regarding the audit:

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[277] Resolution SPD-37 at 4, stating "This Resolution identifies primary and secondary objectives for the audit process and requires large electrical corporations to propose a methodology for conducting the audit in a joint Phase 1 Application," and at 28-29.

> "What audit and accountability framework should be adopted to verify costs are properly recorded by a large electrical corporation to the balancing account associated with work performed pursuant to Pub. Util. Code Section 8388.5?"[278]

6.1. Process to Review Compliance to Primary and Secondary Objectives

As set forth above, in Resolution SPD-37 the Commission states that an audit process should be adopted in this proceeding for confirming compliance with the Primary and Secondary Objectives during the auditor's review of the balancing account. The Joint IOUs present proposals for confirming compliance with each of the Primary and Secondary Objectives established by Resolutions SPD-15 and SPD-37. These proposals are summarized in Table 3 through Table 8 in the Application.[279] The Tables include various data requirements, and substantive findings that would be required by auditors.

However, while both Resolution SPD-37 and the Assigned Commissioner's Scoping Memo requested that the Joint IOUs address whether (and if so what) additional Phase 2 Conditions (beyond the already established Phase 2 Conditions #1 through #4) might be necessary to add to the SB 884 program,[280] the Joint IOUs argued that no additional Phase 2 Conditions are necessary.[281] Hence, as can be seen in Tables 3 through 8 in the Joint IOUs'

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[278] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at 5. This issue applies to subsection (c) of Pub. Util. Code Section 8388.5.

[279] Joint IOUs Application 17-29.

[280] Resolution SPD-37 at 30; *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at 5-6.

[281] Joint IOUs Application at 29-33.

Application, the Joint IOUs' audit proposal vis-a-vis the program's "Primary Objective" of ensuring costs meet the Phase 2 Conditions only speaks to Phase 2 Conditions #1 through #4. More specifically:

- In Table 3, the Joint IOUs present an audit framework for verifying that the total annual costs did not exceed the approved cost cap for a given year, which ties to Phase 2 Condition #1;[282]
- In Table 4, the Joint IOUs present an audit framework for verifying that any third-party funding obtained was applied to reduce the established annual cost cap, which ties to Phase 2 Condition #2;[283]
- In Table 5, the Joint IOUs present an audit framework for determining that the average recorded unit cost for all projects completed in a two-year period did not exceed the approved average unit cost cap, which ties to Phase 2 Condition #3;[284] and
- In Table 6, the Joint IOUs present an audit framework for determining that the average recorded BCR for all projects completed in any given two-year period equals or exceeds the approved threshold BCR value, which ties to Phase 2 Condition #4.[285]

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[282] Joint IOUs Application at 19-20.

[283] Joint IOUs Application at 21-22.

[284] Joint IOUs Application at 23-24.

[285] Joint IOUs Application at 24-26 and stating at 24: "The Auditor should only audit costs (denominator) in the BCR calculation and not the risk reduction benefits (numerator). It is not possible for the utility to provide the actual risk reduction achieved (e.g. the actual amount of wildfire risk removed from the system) from implementing a particular undergrounding project or subproject. Rather, the utility can provide the estimated effectiveness of the mitigation at that location. Additionally, it is not possible for the utility to validate the actual amount of O&M savings achieved by implementing a particular undergrounding project or subproject. For

Footnote continued on next page.

As for the Secondary Objectives of the audit—the Used and Useful Requirement and the Incrementality Requirement—the Joint IOUs propose frameworks for verifying they are met in Tables 7 and 8, respectively.[286]

In the Application, the Joint IOUs further state that (i) the auditors should be provided with the directives of this decision, (ii) that compliance criteria based on this decision be established, and (iii) then the auditor perform a statistically appropriate level of sampling, at the portfolio level, to confirm that costs are properly recorded to the one-way balancing account.[287] The Joint IOUs also recommend the auditor be required to meet specific professional auditor standards, the American Institute of Certified Public Accountants (AICPA) Consulting Standards.[288]

The Staff BCR White Paper does not address the topic of the audit. Several parties offered different recommendations on topics related to the audit in response to the recommendations put forward by the Joint IOUs.

For example, Cal Advocates focuses on the drawbacks of accepting the Joint IOUs' proposed portfolio-level review and states that portfolio-level review will negatively impact the audit by introducing an unacceptable level of

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example, the utility assumes that relocating an overhead line underground will require fewer inspections and maintenance activities on that overhead line."

[286] Joint IOUs Application at 26-29, stating at 26, with respect to the Used and Useful Requirement that: "Each IOU determines if a project and/or subprojects is used and useful based on its own criteria. The auditor will apply the individual IOU's criteria to those projects and/or subprojects the IOU has determined are used and useful to validate that each project and/or subproject meets the established used and useful criteria."

[287] Joint IOUs Application at 18, and Joint IOUs August 7, 2026 Opening Brief at 34.

[288] Joint IOUs Application at 18.

subjectivity into how to allocate costs by, for example, the year.[289] To address these concerns, Cal Advocates recommends additional guardrails on the utilities to prevent this, as follows: (1) any subproject deemed used and useful in a given year should be considered a Qualifying Project and counted against the *cost cap* during that audit period and (2) any subproject deemed used and useful in a given year should be considered a Qualifying Project and counted against the average unit cost cap during that audit period.[290] Similarly, TURN recommends project-level auditing and supports Cal Advocates' proposed auditing rule.[291] TURN supports Cal Advocates' proposed auditing rule, above, stating that the proposal resolves the subjectivity concern without sacrificing transparency.[292] EPUC's position is consistent with Cal Advocates' and TURN's, with EPUC arguing that (1) project-level compliance would be consistent with the Commission's determination, in Resolution SPD-37, that any BCR methodology "shall apply to the project level...."[293] and (2) given this is how the Commission will evaluate forecasted metrics during the Phase 2 Application proceeding, the same granularity of evaluation should apply during Phase 3.[294]

These recommendations are addressed in the sections that follow below and the Commission also clarifies several other topics related to the audit, at the

[289] Cal Advocates August 7, 2026 Opening Brief at 11-12.

[290] Cal Advocates June 9, 2026 Opening Comments at 11-12.

[291] TURN August 7, 2026 Opening Brief at 19.

[292] TURN August 7, 2026 Opening Brief at 19.

[293] Resolution SPD-37 at 26.

[294] EPUC Opening Brief at 32.

request of the Joint IOUs.[295] The clarifications apply to the audit process overall. However, as an initial matter, the Commission generally finds that the audit process articulated and proposed by the Joint IOUs, as described in Tables 3-8 of the Application does not reasonably address the need for an audit process to confirm compliance with the Primary and Secondary Objectives for the recorded costs in the balancing account, as directed in Resolution SPD-37. The Commission further finds that the process set forth in the Tables does not provide a reasonable level of certainty to all stakeholders in terms of how the process will be implemented. Accordingly, the audit process set forth by the Joint IOUs is not adopted, except as noted below. Instead, the Commission adopts the audit process as described below.

6.2. Verifying the Audit Primary Objectives

6.2.1. Confirm Cost Cap Amount

As part of the audit, the auditor will verify that the total annual costs recorded to the balancing account did not exceed the approved cost cap for a given year (Phase 2 Condition #1).

The Joint IOUs recommend that the amount of the cost cap be confirmed by the auditor based on the value adopted for the audit year in any Phase 2 Application decision. Parties did not comment on this topic. The Staff BCR White Paper did not address this topic.

The Commission finds it reasonable to adopt the recommendation of the Joint IOUs for the methodology of verifying Phase 2 Condition #1, where the cost

[295] Joint IOUs Application at 17-29.

cap amount is to be confirmed by the auditor based on the value adopted in the Phase 2 Application decision.

6.2.2. Third Party Funding

As part of the audit, the auditor will verify whether third-party funds were received and how such funds were applied and accounted for in the utility's internal systems (Phase 2 Condition #2).

The Joint IOUs propose a three-step audit process for Phase 2 Condition #2: (1) the utility affirmatively states in writing whether any third-party funding was received in the audit year; (2) if funding was received, the auditor independently reviews the terms of that funding to determine whether it is eligible to offset the cost cap; and (3) the auditor then reviews the utility's books and records to confirm that any eligible funding was actually applied to reduce the cap.[296] No intervening parties commented on this proposal.

The Commission finds it reasonable to adopt the Joint IOUs' proposal regarding third-party funding to ensure the efficient application of the audit.

6.2.3. Average Recorded Unit Cost and BCR Methods

As part of the audit, the auditor will verify that the average, actual unit costs for all projects completed in any given two-year period do not exceed some approved average unit cost (to be determined by the Phase 2 Application decision) (Phase 2 Condition #3).

The Joint IOUs propose that the auditor validate the average recorded unit cost for all projects completed in a given two-year period against the Phase 2

[296] Joint IOUs Application at 21-22.

Application decision threshold. The Joint IOUs do not specify a standardized method for calculating that aggregate average unit cost; instead, they propose that the auditor audit the average unit cost based on a method "developed by the Auditor."[297]

Resolution SPD-37 already defines the average recorded unit cost as cost "per mile of undergrounding performed,"[298] yielding the aggregate as the total recorded undergrounding cost divided by the total miles undergrounded across all completed projects.

Hence, for Phase 2 Condition #3 no separate method or auditor discretion is needed. The Commission adopts Resolution SPD-37's definition for average recorded unit costs for the auditing of Phase 2 Condition #3.

With respect to Phase 2 Condition #4, as part of the audit, the auditor will verify that the average, actual BCR for all projects completed in any given two-year period does not fall below some approved average BCR (to be determined by the Phase 2 Application decision). And, as they did in their proposal for auditing Phase 2 Condition #3, the Joint IOUs likewise propose, for auditing Phase 2 Condition #4, that the auditor validate the average recorded BCR for all projects completed in a given two-year period against the Phase 2 Application decision threshold. However, again, the Joint IOUs do not specify a standardized method for calculating the average recorded BCR. Instead, again, they propose

[297] Joint IOUs Application at 23-24.

[298] Resolution SPD-37 Attachment A, *SB 884 Program: CPUC Guidelines* at 14.

that the auditor audit the BCR average based on a method "developed by the Auditor."[299]

Cal Advocates argues the Joint IOUs' proposal is deficient because it does not articulate how subproject costs and risk are to be weighted within the portfolio average, which risks a misleading aggregate figure. Cal Advocates recommends, alternatively, that a specific, miles-weighted-average BCR calculation be used for Phase 2 Condition #4 rather than leaving the method to the auditor's discretion.[300]

In reply, the Joint IOUs refine their position for Phase 2 Condition #4 and propose calculating the aggregate BCR as total recorded benefits divided by total recorded costs.[301]

As was the case for Phase 2 Condition #3, the Commission finds that leaving the aggregation method to auditor discretion is inadequate, and that an undefined method undermines the transparency, comparability, and auditability that Phase 2 Condition #4 is meant to secure.

However, the Commission does not adopt Cal Advocates proposal for Phase 2 Condition #4, noting mileage is not a proxy for cost or risk-reduction benefit and can overweight long, lower-benefit segments while underweighting short, higher-benefit ones. Instead, for Phase 2 Condition #4, the Commission adopts the Joint IOUs' refined proposal for calculating the average recorded BCR

[299] Joint IOUs Application at 25.

[300] Cal Advocates June 9, 2026 Opening Comments at 55-56.

[301] Joint IOUs July 7, 2026 Reply Comments, Attachment 1 at 37–38.

(as total recorded benefits divided by total recorded costs for all projects, or Subprojects where the Subproject Designation is elected, that became used and useful in the two-year period (the economically consistent aggregation of a benefit-cost ratio, which weights each project's BCR (or Subproject's BCR) by its actual cost and benefit and requires no proxy)).

Furthermore, the Commission adopts the following definitions: "Unit cost" means total recorded (or, for forecasts, total forecasted) capital and expense costs of a project, or of a Subproject where the Subproject Designation is elected, divided by the circuit miles of undergrounding installed. "Average recorded unit cost" in the two-year period means the sum of recorded costs for all projects (or Subprojects) that became used and useful in the two-year period, divided by the sum of circuit miles of undergrounding installed in those projects (or Subprojects). This is consistent with the aggregate method adopted above for the average recorded BCR, and the auditor shall not substitute a different averaging method.

6.3. Compliance with Annual Cost Cap for Balancing Account

In the Application, the Joint IOUs also propose that the three primary cost recovery conditions established in Resolution SPD-15 (Phase 2 Conditions #1, #3, and #4 – i.e., the annual cost cap, BCR values, and unit cost targets) be revised to include a 2% variance threshold before utilities are required to record individual project costs to the memorandum account in Phase 3. More specifically, the Joint IOUs propose the following changes:[302]

[302] Joint IOUs Application at 34-35.

- Phase 2 Condition #1 be revised to: Total annual costs must not exceed 102% of a cap based on the approved cost cap for that specific year.
- Phase 2 Condition #3 be revised to: The average recorded unit cost for all projects completed in any given two-year period (the current year, and the prior year) must not exceed 102% of the approved average unit cost cap for the current year.
- Phase 2 Condition #4 be revised to: The average recorded BCR for all projects completed in any given two-year period (the current year, and the prior year) must exceed or be within 2% of equal or exceed the approved threshold BCR value for the current year.

In support of this recommendation, the Joint IOUs cite the 15% variance threshold previously approved for PG&E's system hardening costs in its 2020 general rate case.[303] However, we take note of three points. First, the variance threshold in PG&E's 2020 GRC was a negotiated term in a settlement in a different context and was not a litigated standard for cost recovery. Second, here, the Joint IOUs seek to change the Phase 2 Conditions previously adopted by the Commission in Resolution SPD-15. However, as previously established by the Commission, no variance was included in such Phase 2 Conditions (i.e., the cost cap, unit costs, and BCR conditions).[304] And third, the Commission finds that, because, in the SB 884 program, each large electrical corporation will have the opportunity to recover amounts accrued above the balancing account caps through the separate Phase 3 memorandum account process, adding variances to

[303] Joint IOUs Application at 34-35.

[304] Resolution SPD-37 at 17-18.

the Phase 2 Conditions is not needed. For these reasons, the recommendation by the Joint IOUs to revise Resolution SPD-15 to include 2% variance thresholds due to forecast uncertainty is not adopted.[305]

6.4. Verifying the Audit Secondary Objectives

The Secondary Objectives of the audit are: (1) verifying project costs recorded to the balancing account tie to projects that are used and useful (Used and Useful Requirement); and (2) verifying the incrementality showing found in Application Requirement No. 2 (i.e., that recorded costs in the balancing account do not duplicate any costs already authorized by another Commission decision, mechanism, or those received from a third party (Incrementality Requirement)).[306]

6.4.1. Used and Useful Requirement

In order to qualify for inclusion in the balancing account, costs must tie to infrastructure that is "used and useful."[307] In their Application, the Joint IOUs propose they be afforded some flexibility in deeming when certain projects and subprojects are considered used and useful.[308] Specifically, the Joint IOUs

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[305] Joint IOUs Application at 34-35.

[306] Resolution SPD-37 at 28-29.

[307] Resolution SPD-15 at 8.

[308] Joint IOUs Application at 20, see Table 3 Note" stating "(A) Over the life of the EUP a utility will complete some number of undergrounding miles in a given year for a project or subproject but will not complete the entire project or subproject until the following year. For example, if a project or subproject consists of 5 undergrounding miles, a utility may complete 2 miles in Year 1 and 3 miles in Year 2. The entire 5-mile project or subproject would be considered qualified in Year 2. However, there may be circumstances in the EUP process (e.g. meeting the Energy Safety Plan Tracking Objectives) where it is reasonable to account for the 2 miles completed and energized in Year 1 even though the 5-mile project or subproject will not be considered a Qualifying Project until Year 2."

propose that each utility determine whether a project or subproject is used and useful based on its own individual criteria, with the auditor applying that same criteria (rather than a single Commission-wide definition) to validate the determination.[309]

Relatedly, while Resolution SPD-37 clarifies that each EUP Audit shall review EUP projects that become "used and useful" during the 12-month period covered by the audit, the Joint IOUs recommend that the "audit year" be defined by the auditor.[310]

In response to these proposals, Cal Advocates notes that the Joint IOUs' proposals permit arbitrary assignment of subprojects to an audit year, meaning that the utility may account for miles completed and energized in one year even though the full project may not be considered used and useful until the following year. As such, Cal Advocates recommends that any subproject deemed used and useful in a given year should be considered and counted against the cost cap and average unit cost cap during the same audit period.[311]

As for determining when certain projects and subprojects are considered used and useful (and therefore, which projects and subprojects are assigned to the audit each year), the Commission adopts the definition of used and useful set forth in Resolution SPD-15 and Resolution SPD-37 and the *SB 884 Data Guidelines*, which essentially states that a project is "used and useful" when

[309] Joint IOUs Application at 26-27.

[310] Joint IOUs Application at 19.

[311] Cal Advocates July 7, 2026 Reply Comments at 11.

complete and providing service to customers. Furthermore, the Commission also requires that any circuit segments that are deemed used and useful (based on this definition) in a given year must be included in the audit covering that same given year. Where a utility elects the Subproject Designation, the audit will be performed at the subproject (RRU) level. Each subproject will be included in the audit covering the year it becomes used and useful and compared against its backcasted values. Recorded costs and benefits for each subproject must be traceable to, and reconcile with, the project from which the subproject was designated.

6.4.2. Incrementality Requirement

Within the SB 884 program, Application Requirement No. 2 requires large electrical corporations to "clearly identify all undergrounding targets [(miles)] and cost forecasts in the Plan [EUP] that overlap with undergrounding targets … and cost forecasts either approved or under consideration in the large electrical corporation's most recent GRC or any other cost recovery venue."[312] The audit will confirm that recorded costs in the balancing account for undergrounding projects and/or subprojects are not also included in a utility's general rate case or other proceeding.

At a high level, the Joint IOUs propose a structure for auditing the incrementality of projects that consists of looking at the previous general rate cases and comparing it against a list of projects submitted by the Joint IOUs.[313]

[312] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 10.

[313] Joint IOUs Application at 28.

No intervening parties commented on this subject.

The Commission adopts the Joint IOUs' proposal with a clarification. We agree the audit should determine incrementality, at a high level, by comparing amounts submitted in the general rate case against a list of projects submitted by the utility, but we clarify that incrementality must be demonstrated by comparing general rate case-authorized (or other Commission-authorized) undergrounding mileage completed (not just amounts spent) against proposed mileage in the EUP.

6.5. Additional Audit Objectives

According to Resolution SPD-37, the "Primary Objective" of the SB 884 program audit is to determine, after costs are recorded to the balancing account, whether such costs do, in fact, meet the Phase 2 Conditions.[314] This decision adopts five additional Phase 2 Conditions, as further discussed in Section 7 below (Phase 2 Conditions #6 through #10). The Commission will apply these five additional Phase 2 Conditions to the Audit.

However, this decision does not adopt a methodology for verifying whether a large electrical corporation satisfies these five new Phase 2 Conditions.

Resolution SPD-37 directed the large electrical corporations to propose, in their instant Application, a methodology for verifying compliance with the existing Phase 2 Conditions, to be addressed in this proceeding. We take the same approach for these five new Additional Phase 2 Conditions. The Commission finds that any large electrical corporation that files a Phase 2

[314] Resolution SPD-37 at 34, Finding of Fact 23.

Application shall propose, in that Phase 2 Application, a methodology for verifying whether it satisfies each of the five new Additional Phase 2 Conditions. Where more than one large electrical corporation files a Phase 2 Application, the proposed methodologies should be consistent, and any difference shall be identified and justified. The appropriate verification methodology for the Additional Phase 2 Conditions will be addressed in the Phase 2 Application proceeding and resolved in the Phase 2 Application decision. Once adopted, that methodology shall be applied within the audit methodology framework adopted in this decision.

6.6. Audit Framework – Project Level

In the Application, which includes no additional Phase 2 Conditions, the Joint IOUs argue the auditor should perform a statistically appropriate level of sampling, at the portfolio level, to confirm that costs are properly recorded to the one-way balancing account.[315]

TURN and Cal Advocates recommend that the audit be conducted on a more granular level, described as the individual project-level, rather than on the portfolio-level, which can be generally described as a higher level. TURN points to potential problems with cost-shifting among various projects to make BCRs and unit costs appear misleading if portfolio-level is relied upon.[316] TURN also points out that the term "portfolio" is undefined.[317] According to TURN, portfolio-level auditing "would also provide utilities considerable discretion in

[315] Joint IOUs Application at 18; Joint IOUs August 7, 2026 Opening Brief at 34.

[316] TURN June 9, 2026 Opening Comments at 2 and 12.

[317] TURN August 7, 2026 Opening Brief at 18.

grouping subprojects, allocating costs and benefits, and determining which projects are included within a portfolio."[318]

Cal Advocates similarly argues that portfolio-level evaluation may obscure individual projects that do not meet cost-effectiveness thresholds by allowing high-performing projects to subsidize underperforming ones.[319] EPUC's position is consistent with Cal Advocates' and TURN's, with EPUC arguing that (1) project-level compliance would be consistent with the Commission's determination, in Resolution SPD-37, that any BCR methodology "shall apply to the project level..."[320] and (2) given this is how the Commission will evaluate forecasted metrics during Phase 2 Application proceeding, the same granularity of evaluation should apply during Phase 3.[321]

The Communication Providers also support project-level audit, stating:

> "A portfolio-level BCR can conceal projects that impose disproportionate costs on communications providers, while project-level review ensures that each project can independently justify its own costs and benefits. Project-level review also better reflects actual project conditions, including inflation, environmental constraints, permitting requirements, and other factors that can significantly affect projects over time. By evaluating projects individually, the Commission can better assess the real-world costs and benefits associated with each undergrounding decision."[322]

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[318] TURN August 7, 2026 Opening Brief at 19.

[319] Cal Advocates June 9, 2026 Opening Comments at 13.

[320] Resolution SPD-37 at 26.

[321] EPUC Opening Brief at 32.

[322] Communications Providers August 7, 2026 Opening Brief at 3.

The Communication Providers maintain that the Joint IOUs are permitted to manage projects but must demonstrate to the Commission each project's "own cost-effectiveness before it imposes costs on third parties. Portfolio-level management is an internal business practice; it should not be a basis for denying visibility for the Commission and affected parties into individual project performance."[323]

In opposition to the proposal by TURN, Cal Advocates, Communication Providers, and EPUC, the Joint IOUs continue to recommend that the audits be performed on the portfolio-level because the Commission's SB 884 review process, as reflected in Resolution SPD-37, is based on portfolio-level review. The Joint IOUs recount that *Draft* Resolution SPD-37 (August 15, 2025) included project-level audits, a proposal that the Joint IOUs argue "would have introduced significant cost recovery risk and uncertainty into the EUP process..."[324] The Joint IOUs state:

> "SPD-37 establishes portfolio-level cost recovery conditions because undergrounding programs are planned, prioritized, and executed as portfolios of projects over multiple years. Individual projects and subprojects may differ in cost, timing, constructability, and forecasted benefits, but the relevant question for cost recovery is whether an approved portfolio satisfies the Commission's adopted requirements. Imposing additional project-level audit tests or balancing-account conditions would effectively create new compliance requirements that are not contained in SPD-37 and

[323] Communications Providers August 7, 2026 Opening Brief at 2-5.

[324] Joint IOUs August 7, 2026 Opening Brief at 4-5.

> would undermine the flexibility intentionally built into the Commission's framework."[325]

First, we note that Resolution SPD-37 specifically asked that the Joint IOUs consider adding project-level conditions to the Phase 2 Conditions. Second, and as will be further discussed in Section 7 below, we adopt herein, several new project-level conditions to the Phase 2 Conditions. Considering this, as well our findings with respect to backcasting, as discussed above in Section 5.5, we find that the SB 884 program is largely based on an analysis of project-level information, rather than portfolio-level information. We agree with TURN, that symmetry between project approval and subsequent auditing will improve transparency and facilitate comparisons between approved forecasts and actual project performance. Therefore, the Commission finds that, to ensure consistency across the SB 884 program, that the audit will be performed at the Risk Reporting Unit (RRU) level. The RRU is the most granular unit at which risk, cost, and BCR are reported. Where a large electrical corporation does not elect the Subproject Designation, the RRU is the "project," and the audit will be performed at the project level. Where it elects the Subproject Designation, the RRU is the Subproject, and the audit will be performed at the Subproject level.

Each subproject will be audited in the year it becomes used and useful. The audit will compare actual results against the subproject's forecasted values, backcast as required in Section 5.5 to reflect the current RRU structure and any updated risk models or risk model inputs. Recorded costs and benefits for each

[325] Joint IOUs July 7, 2026 Reply Comments at 22.

subproject must be traceable to, and reconcile with, the project from which the subproject was designated.

6.7. Auditor Selection

Resolution SPD-15 and Resolution SPD-37 did not address the method to use for the selection of an auditor. No party raised this issue. The Staff BCR White Paper did not address this issue.

As noted above, the Scoping Memo asks what audit and accountability framework should be adopted in this proceeding to verify costs are properly recorded by a large electrical corporation to the balancing account.[326] A comprehensive audit framework inherently includes the selection of the audit team, mandating that auditor selection criteria evaluate both objectivity and technical competence to fulfill the audit objectives. Further, the Commission should establish a process for the selection of an auditor as part of this proceeding because the timeline for resolving a proceeding initiated by a utility for review of a 10-year electric undergrounding plan is compressed, set at nine months, and is shorter than the typical Commission proceeding of 18-months. Any process regarding the selection of an auditor that can be put in place now will facilitate the expeditious resolution of any future proceedings within the nine-month timeframe.

Therefore, to promote the expeditious resolution of any future proceedings under the SB 884 process, and because the selection of an auditor is required by what is in scope in this proceeding, the Commission directs the Joint

[326] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026) at 5.

IOUs to submit via Tier 2 Advice Letter within 45 days of the effective date of this decision, a list of auditors qualified to perform this audit, together with a description of how the auditors meet the Audit Standards, set forth below.

6.8. Audit Standards

The Joint IOUs recommend that the audit be conducted under the American Institute of Certified Public Accountants (AICPA) Consulting Standards.[327] In support of this recommendation, the Joint IOUs state that (1) AICPA provides for flexibility to accommodate unique circumstances, such as those presented under SB 884; (2) the AICPA is designed for commercial entities, such as the utilities, while other standards, such as the Generally Accepted Government Auditing Standards (GAGAS), are primarily focused on government entities; and (3) the AICPA provides comprehensive guidance for performing consulting engagements and reflects recognized professional practices, such as objectivity, competency, and due professional care.[328]

EPUC recommends that the auditor be required to meet the standards of the Generally Accepted Government Auditing Standards (GAGAS) because these standards are used for government-mandated audits to ensure greater public accountability.[329]

The Commission finds the use of standards for government-mandated audits (GAGAS) reasonable and, therefore, requires the audit to meet the Generally Accepted Government Auditing Standards because these standards

[327] Joint IOUs Application at 18-19.

[328] Joint IOUs Application at 18-19.

[329] EPUC March 16, 2026 Protest to Application at 8.

govern third-party audits of government entities and are also used for audits of entities that receive public or ratepayer funds.

6.9. Single Audit Report

The Joint IOUs recommend a single report structure to promote efficiency. The Commission agrees. The Commission finds that a single audit report structure is adopted for the audit. The single audit report will cover all Phase 2 Conditions and the used and useful and the incrementality showings. The audit report will be filed into the application proceeding initiated by the utility for approval of its 10-year electric undergrounding plan. The Commission will accept filing of the report, even if the proceeding is closed, and parties are permitted to file comments in response to the report.

6.10. Auditing the Benefits

The Joint IOUs state that that "[t]he Auditor should only audit costs (denominator) in the BCR calculation and not the risk reduction benefits (numerator)" because "it is not possible for the utility to provide the actual risk reduction achieved…."[330] The Joint IOUs reason that realized risk reduction and realized O&M savings "are not feasible" to audit because they are "inherently modeled or estimated rather than directly observable ex post.[331]

TURN responds to the Joint IOUs and disagrees, stating:

> "That objection has a straightforward response. Two implementation-level facts about a completed project can be compared against the forecast without independently remodeling risk. These two implementation-level facts are the actual number of

[330] Joint IOU Application at 24.

[331] Joint IOUs July 7, 2026 Reply Comments at 23.

> overhead miles undergrounded versus the forecast, and whether the specific circuit segments identified in the forecast were the segments actually undergrounded. Where actual miles differ from forecast, the auditor can scale the forecasted benefit proportionally, or the utility can provide the risk/risk-reduction value specific to the additional or omitted segments. Where different segments were undergrounded than forecast, the utility — not the auditor — bears the burden of recalculating risk reduction using its own approved risk model. This mechanism requires no independent risk modeling by the auditor and directly responds to the Joint IOUs' stated objection that any benefit-side auditing is infeasible."[332]

The Commission adopts the recommendation of TURN for "auditing" benefits in the BCR because the process is feasible and will enhance the transparency of the SB 884 process. More specifically, the Commission finds that if the circuit segments actually undergrounded differ from those identified in the applicable forecast , the large electrical corporation must recalculate its risk value benefits for the actually, as-built segments using the risk model version and inputs applicable under the backcasting methodology adopted in Section 5.5. Further, the large electrical corporation must provide the auditor with the recalculated risk values and supporting inputs. Where a large electrical corporation contends that a difference between forecasted and actual values is attributable to a change in a risk model or model input, it bears the burden of demonstrating that effect, including by reporting, for comparison purposes only, the actual BCR calculated under the risk model version underlying the Screen 4 forecast.

[332] TURN August 7, 2026 Opening Brief at 19-20 (footnotes in original omitted).

6.11. Meaning of Audit Report

The Joint IOUs request clarification of the meaning of the term "audit report." Resolution SPD-37 states at Attachment A (SB 884 Program: CPUC Guidelines) that the audit will result in an "audit report."[333] The Joint IOUs recommend that the Commission clarify that the audit report will address compliance with the Primary and Secondary Objectives regarding the cost recovery conditions for the SB 884 program and not, as described by the Joint IOUs, a "true financial audit."[334]

In Resolution SPD-37, the Commission uses a variety of terms, including "EUP Audit," "audit," "audit process," "audit procedure," "audit details," "audit objectives," and "audit methodology." The terms "audit report" is largely described in Resolution SPD-37, as follows:

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

[333] Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025)* at 17.

[334] Joint IOUs Application at 17.

> Phase 2 Application proceeding to consider refunds as described below."[335]

The Commission finds that in the context of the Commission's future review of any applications filed under the SB 884 process, that the scope of the audit report is to confirm compliance with the Primary and Secondary Objectives (also referred to as Conditions).

7. Additional Phase 2 Conditions

The April 10, 2026, Assigned Commissioner's Scoping Memo set forth the following third and final issue to be considered in this proceeding: "What additional Phase 2 Conditions, if any, are necessary to ensure that any costs recorded to the balancing account by an electric utility are just and reasonable?"[336]

7.1. Background

As discussed above, in Resolution SPD-15, the Commission adopted five initial Phase 2 Conditions (Phase 2 Conditions #1 through #5).[337] These five initial Phase 2 Conditions can be summarized as follows:[338]

> (1) total annual costs for each year of the 10-year program must not exceed an annual cost cap (such cap to be determined by the Phase 2 Decision based on the record in the Phase 2 proceeding) (Phase 2 Condition #1);
>
> (2) all third-party funding obtained throughout the duration of the program shall be applied to reduce any established

[335] Resolution SPD-37 at 23 (fn. 63 in original omitted).

[336] *Assigned Commissioner's Scoping Memo and Ruling* A.26-02-005 (April 10, 2026).

[337] Resolution SPD-15, Attachment 1, *SB 884 Program: CPUC Guidelines* at 10-11.

[338] Resolution SPD-15 Attachment 1, *SB 884 Program: CPUC Guidelines* at 11.

cost cap for the year in which the third-party funding is obtained (Phase 2 Condition #2);

(3) the average, actual unit costs for all projects completed in any given two-year period must not exceed some approved average unit cost (such unit cost to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #3);

(4) the average, actual BCR for all projects completed in any given two-year period must not fall below some approved average BCR (such BCR to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #4); and

(5) any further conditions (to be determined by the Phase 2 Application decision based on the record in the Phase 2 Application proceeding) (Phase 2 Condition #5).

When the Commission established these five initial Phase 2 Conditions, it stated that the Phase 2 Conditions "represent the conditions that **the Commission finds are necessary and sufficient to determine that the costs authorized for recovery in the balancing account are just and reasonable**."[339]

However, after the Commission established these five initial Phase 2 Conditions, Energy Safety issued its own review process that includes filtering potential undergrounding projects through four increasingly specific screens (*Energy Safety EUP Guidelines* Screens 1, 2, 3, and 4). Each screen reduces the

[339] Resolution SPD-15 at 5 (emphasis added).

uncertainty associated with any project's forecasted costs and benefits, as it moves towards becoming "fully scoped."[340]

The Commission quickly recognized that "significant changes" can be made to the forecasted metrics of any potential undergrounding project as it moves through *the Energy Safety EUP Guidelines* Screens 1-4.[341] And that this is especially true when projects have yet to move through Screen 3. As we noted in Resolution SPD-37:

> "PG&E recognized that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs. PG&E stated that Screen 2... "is *well before a utility has developed a sound project cost estimate*. In PG&E's case, a sound cost estimate is developed after project estimating." [footnote omitted.] … It is only at [*Energy Safety EUP Guidelines*] Screen 4 when an undergrounding project is fully scoped, and estimating is complete that a reasonably accurate cost forecast can be provided."[342]

The issue, in the case of the Commission's review of an EUP, is that "only a small fraction" of the projects presented to the Commission for review in any Phase 2 Application will have moved through Screen 3 (i.e., the large majority of projects that the Commission reviews during a Phase 2 Application proceeding will have only passed through the *Energy Safety EUP Guidelines* Screen 2).[343]

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[340] Resolution SPD-37 at 6-8.

[341] Resolution SPD-37 at 8.

[342] Resolution SPD-37 at 20, *citing* PG&E responses to the "Technical Working Group Questions," June 24, 2025, at 7 (emphasis added), and at 6 ("PG&E indicates that Screen 2 cost estimates can vary from +100% to -50%, whereas at the completion of estimating that range is reduced to +20% to -15%.").

[343] Resolution SPD-37 at 7.

For this reason, in Resolution SPD-37, we clarified that:

> "...the large majority of forecasted data available to the Commission at the time a Phase 2 Application is filed, and upon which its EUP cost approval conditions in the Phase 2 Decision will be based, will not be sufficiently precise to provide the intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15. Accordingly, this Resolution requires a future Phase 1 Application process to close any such gaps and ensure the Commission has the information essential to determining the appropriateness of cost recovery."[344]

The Commission then directed the Joint IOUs to file the instant Application and include:

> "a proposal for any additional portfolio or project-level conditions necessary to ensure that costs booked to balancing accounts are just and reasonable. At a minimum, large electrical corporations shall consider the following types of quantitative conditions: conditions that address how an undergrounding project compares to alternative mitigations; conditions that address how the actual BCR of a project compares to its forecasted BCR; conditions that address how the actual unit cost of an undergrounding project compares to its forecasted cost. For each quantitative condition, large electrical corporations should propose a numerical threshold that can be used to evaluate whether the condition has been met."[345]

Under the SB 884 framework, compliance with the Phase 2 Conditions is first asserted by the utility and later verified by the Commission. As Resolution SPD-37 explains: "The large electrical corporation initially asserts that EUP project costs have met the Phase 2 Conditions upon recording in the one-way

[344] Resolution SPD-37 at 8 (emphasis added).

[345] Resolution SPD-37 at 7 (emphasis added).

balancing account. It is only during the audit process that the Commission verifies whether the Phase 2 Conditions were met (Primary Objectives)."[346] Because the utility makes its assertion when costs are recorded, the choice of account (balancing account or memorandum account) is made at that time. Costs that do not meet the Phase 2 Conditions may not be recorded to the one-way balancing account. The utility may record those costs instead to the Phase 3 memorandum account, subject to the memorandum account cap and review for justness and reasonableness in a Phase 3 Application. The utility's discretion is limited to that choice. The utility may not transfer costs from the one-way balancing account to the memorandum account after they are recorded

7.2. Discussion

The Joint IOUs do not recommend any additional Phase 2 Conditions for the SB 884 program.[347] According to the Joint IOUs, the information already required in either the Commission *SB 884 Data Guidelines* and/or *Energy Safety EUP Guidelines* provides sufficient information to ensure that the costs recorded to the balancing account are just and reasonable.[348] The Joint IOUs oppose applying any Phase 2 Conditions on a project or subproject-level.[349] Rather, the Joint IOUs support portfolio-level Phase 2 Conditions for evaluating cost recovery and do not recommend adding any project-level conditions.[350]

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[346] Resolution SPD-37 at 11.

[347] Joint IOUs Application at 29.

[348] Joint IOUs Application at 29.

[349] Joint IOUs Application at 29.

[350] Joint IOUs Application at 29.

According to the Joint IOUs, the already established portfolio-level cost recovery Phase 2 Conditions recognize the real-world challenges inherent in managing a complex utility system hardening program and allow utilities to prudently manage a portfolio of work within established metrics.[351] The Joint IOUs state that managing undergrounding program costs at the portfolio level is "consistent with the well-established process for approving funding and managing programs at the portfolio-level in a utility's GRC [General Rate Case]."[352]

As to Resolution SPD-37's specific direction to consider conditions that address how an undergrounding project compares to alternative mitigations,[353] the Joint IOUs argue no such conditions are necessary. According to the Joint IOUs, information regarding alternative mitigations is provided to Energy Safety and the Commission through the existing data requirements.[354] The Joint IOUs also state that additional information would potentially create inconsistencies in data filings.[355]

As to Resolution SPD-37's specific direction to consider conditions that address how actual BCRs and actual unit costs compare to forecasts,[356] the Joint

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[351] Joint IOUs Application at 29.

[352] Joint IOUs Application at 29.

[353] Resolution SPD-37 at 30.

[354] Joint IOUs Application at 30.

[355] Joint IOUs Application at 30-31, and fn. 46, 47 and 48 *citing* Resolution SPD-37, Attachment A, *SB 884 Program: CPUC Guidelines (Dec. 10, 2025),* Appendix 1, *SB 884 Project List Data Requirements* at A1-11 to A1-22, Tables 1 and 2.

[356] Resolution SPD-37 at 30.

IOUs argue no such conditions are necessary. The Joint IOUs support portfolio-level cost recovery Phase 2 Conditions, stating:[357]

> "The IOUs support the portfolio-level cost recovery conditions for costs recorded to the balancing account with the opportunity to record certain project costs to the memorandum account for further review. These cost recovery conditions address project execution realities where some projects cost less than forecast and others cost more, while still requiring a large electrical corporation to prudently manage its overall project portfolio. The IOUs do not recommend any additional portfolio-level conditions beyond those already included in the Energy Safety EUP Guidelines and the Commission's SB 884 Program Guidelines, which address how the actual unit cost of an undergrounding project compares to its forecasted cost. The IOUs do not recommend any project-level cost recovery conditions."[358]

According to the Joint IOUs, scoping, or project planning, involves estimating the location and route of the underground asset based on desktop mapping reviews.[359] The project cost estimate is refined as the large electrical corporation more fully develops the project, which includes more accurately determining the undergrounding route to address obstacles in the planned route that are varied through field visits by grid design engineers, project estimators, and public safety specialists.[360] The scope of the actual construction and materials

[357] Joint IOUs Application at 3.

[358] Joint IOUs Application at 31.

[359] Joint IOUs Application at 31.

[360] Joint IOUs Application at 31.

needed are not fully confirmed until the underground project estimating is complete.[361]

TURN, EPUC, Cal Advocates, and Communications Providers make recommendations. The Staff BCR White Paper does not address this topic. MGRA does not address this topic.

TURN frames this issue as a matter of concern in its March 13, 2026, Protest to the Application. Responding to the Joint IOUs' position that Energy Safety and Commission existing Requirements provide sufficient information, TURN states that "cross-filing information requirements do not substitute for enforceable cost recovery conditions." TURN notes that without project conditions, the Commission has no means to deny cost recovery in instances where undergrounding was selected over a more cost-effective alternative.[362] In later filings, TURN provides no specific recommendations, but argues that the Joint IOUs' proposal (that no additional Phase 2 Conditions are needed) is not reasonable.[363] TURN supports project level information.[364] TURN also states, "[i]ndeed, exactly how a 'portfolio' will be defined appears to be entirely up to IOU discretion."[365]

Cal Advocates supports project-level analysis. Cal Advocates states that more granular information, such as project information, is necessary for

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[361] Joint IOUs Application at 31.

[362] TURN March 13, 2026 Protest at 7-8.

[363] TURN March 13, 2026 Protest at 7-8.

[364] TURN June 9, 2026 Opening Comments at 7; TURN August 7, 2026 Opening Brief at 17-18.

[365] TURN August 7, 2026 Opening Brief at 18.

efficiency, because portfolio-only evaluation could approve inefficient (BCR < 1) subprojects, and there is no rational basis for recovering the cost of an inefficient subproject.[366] Cal Advocates agrees with TURN that additional Phase 2 Conditions are needed.[367] Cal Advocates' proposals are based on a project level analysis because, according to Cal Advocates, project level analysis with projects demonstrating a forecasted BCR greater than 1, is required by Resolution SPD-37.[368]

EPUC makes recommendations to improve the proposals by other parties.[369]

The Communications Providers offer several recommendations that, generally, support project level review under the Phase 2 Conditions.[370] Communications Providers seek assurance that undergrounding should only be selected when the record demonstrates that it is the most cost-effective mitigation after all costs, including communication provider relocation and undergrounding costs, are considered.[371] This position does not directly address additional Phase 2 Conditions but appears to provide indirect support.

After considering each of these arguments, the Commission finds that additional Phase 2 Conditions are needed to provide the intended cost

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[366] Cal Advocates June 9, 2026 Opening Comments at 11, 12, 56, and 65.

[367] Cal Advocates June 9, 2026 Opening Comments at 56; Cal Advocates August 7, 2026 Opening Brief at 24-29.

[368] Cal Advocates June 9, 2026 Opening Comments at 56.

[369] EPUC August 7, 2026 Opening Brief at 36.

[370] Communications Providers August 7, 2026 Opening Brief.

[371] Communications Providers August 7, 2026 Opening Brief at 10.

containment controls and ratepayer protections anticipated in Resolution SPD-15. The additional Phase 2 Conditions (Phase 2 Conditions #6 through #10) are set forth and adopted below.

7.3. Adoption of Additional Phase 2 Conditions

This decision adopts the five additional Phase 2 Conditions set forth below:

Phase 2 Condition #6: All costs must be associated with a project whose forecasted undergrounding BCR (as presented in the Phase 2 Application proceeding) was at least as high as the forecasted BCR (as presented during the Phase 2 Application proceeding) of the best-performing alternative mitigation.

Phase 2 Condition #7: Once any project passes through the *Energy Safety EUP Guidelines* Screen 4, if its fully scoped Energy Safety Screen 4 forecasted undergrounding BCR has fallen below the forecasted BCR of the best-performing alternative (as presented during the Phase 2 Application proceeding), then a large electrical corporation must re-evaluate the best-performing alternative using updated inputs consistent with those used for the Screen 4 undergrounding forecast and reconfirm that undergrounding project (as fully scoped and forecasted) remains at least as cost-efficient as the best-performing alternative.

Phase 2 Condition #8: Any project's actual BCR may not be more than 30% less than its fully scoped, *Energy Safety EUP Guidelines* Screen 4 forecasted BCR.

Phase 2 Condition #9: Any project's actual unit cost may not be more than 30% more than its fully scoped, *Energy Safety EUP Guidelines* Screen 4 forecasted unit cost.

> **Phase 2 Condition #10**: Any project's fully scoped, *Energy Safety EUP Guidelines* Screen 4 forecasted BCR must remain at or above 1.

The Commission finds these new conditions are needed given the large uncertainties associated with Phase 2 Application cost forecasts. As already recognized by the Commission in Resolution SPD-37, the large majority of project data that the Commission will have during its Phase 2 Application assessment will be very early stage (i.e., it will have only passed through *Energy Safety EUP Guidelines,* Screen 2). As we noted in Resolution SPD-37:

> "PG&E recognized that Screen 2 data is not sufficiently mature to determine reasonably accurate project costs. PG&E stated that Screen 2... "is *well before a utility has developed a sound project cost estimate*. In PG&E's case, a sound cost estimate is developed after project estimating." [footnote omitted.]… It is only at [*Energy Safety EUP Guidelines*] Screen 4 when an undergrounding project is fully scoped, and estimating is complete that a reasonably accurate cost forecast can be provided."[372]

This was confirmed, during the course of this proceeding, when PG&E shared that only after projects move through *Energy Safety EUP Guidelines* Screen

[372] Resolution SPD-37 at 20, *citing* PG&E responses to the "Technical Working Group Questions" June 24, 2025 at 7 (emphasis added) and at 6 ("PG&E indicates that Screen 2 cost estimates can vary from +100% to -50%, whereas at the completion of estimating that range is reduced to +20% to -15%.")

4 do their cost estimates become materially more certain.[373] Indeed, the Screen 4 estimate is the most mature forecast available before construction.[374]

For this reason, in Resolution SPD-37, the Commission (1) stated it would not have sufficiently precise data at the time of a Phase 2 Application to provide the "intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15"[375] and (2) it directed the Joint IOUs to consider at least three types of conditions: (a) those that compare undergrounding to alternatives, (b) those that compare actual BCRs to forecasted BCRs, and (c) those that compare actual unit costs to forecasted unit costs. We find that all three types of conditions are needed. While the Joint IOUs argue that information regarding alternative mitigations is provided to Energy Safety and the Commission through the existing data requirements, we agree with TURN that without a project condition that ties to alternative mitigations, the Commission will have no means of protecting ratepayers from instances where undergrounding is selected over a more cost-effective alternative. Moreover, we note the importance

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[373] Joint IOU Responses to the ALJ Ruling on June 18, 2026, Attachment 1, at 1-4, where PG&E shows that, at the time of the Phase 2 Application, the majority of projects will have completed only a Class 5 AACE (Association for the Advancement of Cost Engineering) International estimated forecast, which corresponds to Screen 2 in the OEIS Guidelines. The uncertainty of Class 5 estimates can be as wide as -50 to +100 percent. Thus, the forecast at the Phase 2 Application is not very certain and does not lend itself to comparison with a completed project except at a very wide threshold level. However, by the time a project has passed through Screen 4 (Project Prioritization) of the OEIS Guidelines, the OEIS requires that a project passes a more stringent Screen 4, which PG&E also shows its estimate corresponds to a more certain AACE Class 4 (−30 percent to +50 percent) estimate.

[374] TURN June 9, 2026 Opening Comments, Attachment (SPD-37-JointIOU-PhI_DR_TURN_001), PG&E Answer 010(b) at 17.)

[375] Resolution SPD-37 at 8.

of comparing undergrounding to alternative mitigations is found in subsection (c) of Section 8388.5. The additional Phase 2 Conditions #6 and #7, create conditions that allow the Commission to protect ratepayers from instances where undergrounding is selected over a more-cost effective alternative, with the additional Phase 2 Condition #7 continuing the protection through the *Energy Safety EUP Guidelines* more accurate Screen 4. For clarity, additional Phase 2 Conditions #6 and #7 govern whether costs associated with an undergrounding project qualify for recording in the one-way balancing account. They do not alter Energy Safety's authority to evaluate, screen, approve, or deny a project or EUP under Public Utilities Code Section 8388.5(d).

Furthermore, while we do recognize the challenges inherent in managing a complex utility system, and that managing costs is often, as the Joint IOUs point out, done at the portfolio level (for example in connection with general rate case filings), we note that the SB 884 program is unique in that costs are potentially "conditionally approved" within it across a 10-year time frame. This is precisely why Resolution SPD-15 established Phase 2 Conditions #1 through #5[376] -- the same Phase 2 Conditions Resolution SPD-37 later directed the Joint IOUs to consider supplementing here. Moreover, the Phase 3 memorandum account that was established in Resolution SPD-15 exists precisely to address the inherent uncertainties associated with planning across a 10-year time frame. All costs that are incurred to execute the EUP that do not meet the Phase 2 Conditions can

[376] *See* Resolution SPD-15 at 9-10 *citing* the "lengthy period of construction" as the reason for, among other things, ratepayer protections like the Phase 2 Conditions.

potentially be recorded in the Phase 3 memorandum account. For these reasons, coupled with the large uncertainties associated with any Phase 2 Application cost forecasts, we find new project-level conditions are needed to ensure costs booked to the balancing accounts are just and reasonable.

Furthermore, TURN, supported by EPUC, argues that, at the project-level, a project's forecasted economic metrics should be compared to its actual performance (after the project is implemented).[377] We agree, and we find that the additional Phase 2 Condition #8 and Phase 2 Condition #9 represent reasonable versions of the project-level quantitative conditions that the Commission directed the Joint IOUs to consider in the instant Application for comparing actual BCRs and unit costs to forecasted BCRs and unit costs.[378]

We also find a 30% threshold value is reasonable for both Phase 2 Condition #8 and Phase 2 Condition #9. The applicable "forecast" to be used when applying both Conditions will be the *Energy Safety EUP Guidelines* Screen 4 forecast, which, according to PG&E, links to the AACE Class 4 estimate accuracy range, which states deviations between the forecast and actuals should range from -30% to +50%.[379] PG&E states that it aligns its cost estimating processes with the AACE classification system,[380] and the Joint IOUs rely on the same

[377] TURN June 9, 2026 Opening Comments at 11; EPUC August 7, 2026 Opening Brief at 32.

[378] Resolution SPD-37 at 30.

[379] Joint IOU Responses to June 18, 2026, ALJ Ruling, Attachment 1, at 2 (PG&E Answer 1(a), Table 1), 4 (PG&E Answer 1(c), Table 3).

[380] Joint IOU Responses to June 18, 2026, ALJ Ruling, Attachment 1 at 2 (PG&E Answer 1(a)).

framework to support their proposed 30% uncertainty factor.[381] A 30% threshold is therefore modestly more restrictive than the upper bound of the AACE Class 4 estimate range. The same holds on the benefit side: with benefits held constant, a 30% decline in BCR corresponds to a cost increase of roughly 43%, which is also within the Class 4 upper bound.

We find the 30% threshold represents a reasonable cost-containment threshold that leaves reasonable room for execution risk (as the large electrical corporations move their projects from Screen 4 through implementation) while also ensuring that material departures from Screen 4 forecasts are not recovered through the balancing account.

As for Phase 2 Condition #10, we find it also is reasonable, as it brings forward the existing Phase 2 Application Requirement (that only projects with BCRs greater than or equal to 1 may be included in the Phase 2 Application) to the *Energy Safety EUP Guidelines* Screen 4 stage.

8. Consideration of Other Factors in Selecting Mitigation Alternatives

The Joint IOUs recommend allowing a large electrical corporation to consider other local factors along with BCR values when selecting mitigation alternatives. According to the Joint IOUs,

> "[w]hile large electrical corporations use sophisticated risk models to analyze system risk and select the most appropriate mitigation solution for a specific location, there are still limitations to these models. It is appropriate, therefore, to supplement these modeling results by considering other factors to ensure that the large electrical corporation is selecting the most effective mitigation considering

[381] Joint IOUs Application at 36, fn. 50.

> other environmental factors and state policy objectives. Because each IOU's risk models and service territory are different, each IOU necessarily considers other factors specific to their operations. It is therefore reasonable to allow each IOU to identify and consider those other criteria that may factor into mitigation selection and prioritization."[382]

The Joint IOUs state that, because "wildfire risk models are not designed to model all exogenous environmental factors, or the vulnerability of populations in proximity to wildfire prone locations, utilities recognize the need to supplement their modeling results by considering additional factors such as ingress/egress risk, tree-strike risk, and PSPS risk."[383] Therefore, the Joint IOUs recommend that "[a]dopting a more holistic approach to project selection by considering factors outside of the wildfire risk model acknowledges the importance of these additional considerations."[384]

The Joint IOUs suggest that a number of local factors may be evaluated to determine if undergrounding is the "appropriate mitigation."[385] The Joint IOUs describe some of these factors as "local factors not well represented in risk models" and state that these could include Ingress/Egress Risk, Addressing Tree Strike Risk, Considerations Around PSPS Risk.[386] The Joint IOUs state that they will "continue to consider undergrounding if the BCR for an undergrounding project is within 70 percent of the BCR for an alternative mitigation like covered

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[382] Joint IOUs Application at 35.

[383] Joint IOUs Application at 36.

[384] Joint IOUs Application at 36.

[385] Joint IOUs Application at 36.

[386] Joint IOUs Application at 37-38.

conductor plus fast trip settings (this is referred to as an "estimate uncertainty factor")."[387] In such situations—where the BCR of an undergrounding project is less than the BCR of an alternative, but still within 70 percent of the alternative's BCR—the Joint IOUs propose that they will then evaluate the aforementioned "local factors" that, according to the Joint IOUs, are "not well represented in the risk models."[388]

The Commission does not adopt the recommendation by the Joint IOUs for permission to consider local factors outside risk models when forecasted BCRs for undergrounding projects are less than but within 70 percent of the BCRs forecasted for alternatives. The Commission finds consideration of other local factors outside the BCR unnecessary under the SB 884 process.

First, we note PG&E already captures ingress/egress risk in its Wildfire Consequence Model v4 through the AFN (egress) and Terrain Difficulty Index (ingress).[389] We also note PG&E already incorporates granular PSPS lookback data into the BCR as well.[390] Likewise, SDG&E applies an ingress/egress

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[387] Joint IOUs Application at 36-37, states: "The local factors may include PSPS dynamics, tree-strike risk, and ingress/egress risks (discussed in Sections A(1) through A(3) below) informed by engineering studies and subject-matter-expert reviews conducted during the project scoping phase. For example, PG&E leverages Public Safety Specialists, generally retired fire fighting professionals, to evaluate local conditions including detailed ingress/egress considerations." (emphasis added.) The Joint IOUs use of the phrase "may include" suggests that other factors not specifically identified will also be evaluated.

[388] Joint IOUs Application at 36.

[389] Joint IOU Responses to ALJ Ruling (June 18, 2026), Attachment 1 at 14.

[390] Joint IOU Responses to ALJ Ruling (June 18, 2026), Attachment 1 at 20.

multiplier in its consequence model,[391] and models vegetation contact at the span level within the BCR.[392] Second, we agree with Cal Advocates that deriving the proposed uncertainty factor of 30% from the Association for the Advancement of Cost Engineering (AACE) ranges, which apply to capital-cost estimating, seems more appropriate for addressing uncertainty in realized construction costs than modelling uncertainty.[393] Third, we note, in agreement with Cal Advocates, that the Joint IOUs proposal is asymmetric, in that it only ever operates to keep undergrounding projects in consideration.[394] It operates exclusively to relax the BCR threshold for undergrounding relative to alternative mitigations. Finally, we also note that the additional Phase 2 Condition #6 requires that all undergrounding costs recorded to the balancing account be associated with a project whose forecasted BCR is at least as high as the forecasted BCR of the best-performing alternative. Adopting the Joint IOUs' proposal here would conflict with the intent of newly adopted Phase 2 Condition #6.

9. Incorporating Previously Scoped Projects

The Joint IOUs state that it may be reasonable to include a previously scoped project in the EUP undergrounding portfolio of work.[395] The Joint IOUs explain that in the past years, utilities have scoped several projects that may not meet certain EUP requirements because, for example, projects selected and

[391] Joint IOU Responses to ALJ Ruling (June 18, 2026), Attachment 1 at 16.

[392] Joint IOU Responses to ALJ Ruling (June 18, 2026), Attachment 1 at 18–19.

[393] Cal Advocates June 9, 2026 Opening Comments at 63.

[394] Cal Advocates June 9, 2026 Opening Comments at 64.

[395] Joint IOUs Application at 39.

scoped were based on a previous version of the risk model.[396] Because a project was selected based on the previous risk model, the Joint IOUs state it may not be possible to demonstrate that it meets the Energy Safety screening requirements, even though at the time it was selected it was a high-wildfire-risk-ranked circuit segment.[397] The Joint IOUs claim that "[e]ven if the project does not meet all the EUP requirements, it is reasonable to pursue such an undergrounding project because, at the time it was selected and scoped, it was forecast to significantly reduce wildfire and reliability risk—the two key factors in selecting and pursuing projects in the EUP."[398]

The Staff BCR White Paper does not address this topic. No parties address this topic, except for TURN.

TURN states that the proposal by the Joint IOUs functions as a "blanket exception" that could allow projects of questionable cost-effectiveness to enter the program and recover costs through the balancing account without meaningful review.[399]

The Commission finds that costs of undergrounding projects that a large electrical corporation scoped, or that were authorized and funded, before the effective date of its EUP may be recorded to the EUP balancing account only if the large electrical corporation demonstrates that: (1) the miles and costs for

[396] Joint IOUs Application at 39.

[397] Joint IOUs Application at 39.

[398] Joint IOUs Application at 39.

[399] TURN March 13, 2026 Protest at 8. "TURN reserves the right to address the scope and conditions of any such exception." TURN did not further address this topic.

which it requests EUP recovery are incremental to all undergrounding miles and costs authorized or recovered in any general rate case or other cost recovery proceeding, consistent with Application Requirement No. 2 and Phase 2 Conditions #1 through #4 of Resolution SPD-37, and the additional conditions (Phase 2 Conditions #6 through #10) adopted in this decision, and (2) any previously authorized scope, or portion thereof, is reflected in the no-build baseline, with that scope's mileage and associated risk-reduction benefits excluded from the BCR and unit cost calculations. Where a large electrical corporation's authorized undergrounding funding is established at a program or aggregate forecast level rather than by project, the incrementality demonstration shall be made against authorized program.

10. SB 884 Project List Data Requirements Guidelines and SB 884 Project List Data Template

The *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template* should be read consistent with the changes made herein. The Commission staff will prepare a revised version of these documents consistent with the changes made herein.[400] These revised versions of these documents will be shared with the service list of this proceeding.

11. Summary of Public Comment

Rule 1.18 of the Commission's Rules of Practice and Procedure allows any member of the public to submit written comment in any Commission proceeding

[400] Resolution SPD-37, Ordering Paragraph 11: "11. We authorize Safety Policy Division to make future updates and changes to the SB 884 Project List Data Requirements Guidelines and SB 884 Project List Data Template after hosting at least one technical working group meeting to present and discuss the changes." Res. SPD-37 at 37.

using the *Public Comment* tab of the online *Docket Card* for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding. Ten public comments appear on the *Docket Card* for this proceeding. Most comments generally request that the Commission continue to support undergrounding based on concerns that overhead infrastructure may ignite fires and that undergrounding may reduce wildfire and service interruption risks. One public comment expresses support for the proposed decision's benefit-cost framework and consideration of alternatives to undergrounding, including distributed generation and overhead line hardening.

12. Motions

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are denied.

13. Comments on Proposed Decision

The proposed decision of Commissioner John Reynolds in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. EPUC, Joint IOUs, MGRA, Pacific Bell Telephone Company D/B/A AT&T California (AT&T), and TURN filed comments on November 5, 2026, and reply comments were filed on November 10, 2026 by Cal Advocates, TURN, Joint IOUs, and EPUC, and MGRA.

These comments are summarized and addressed in the body of the decision, as appropriate. After reviewing the comments, we have revised the decision as discussed in the body of the decision. We otherwise decline to modify the proposed decision. Furthermore, while the Joint IOUs argue that the decision is inconsistent with SB 884 and improperly limits the role assigned by the Legislature to the Office of Energy Infrastructure Safety (Energy Safety), we find no error on this basis. SB 884 establishes distinct responsibilities for Energy Safety and the Commission. Under Pub. Util. Code Section 8388.5, Energy Safety reviews and approves Electrical Undergrounding plans, while the Commission reviews applications for conditional approval of plan costs. The decision establishes the methodology, audit framework, and cost-recovery conditions the Commission will apply when evaluating requests for conditional approval of costs under the SB 884 program. The requirements adopted in the decision are necessary to carry out the Commission's statutory responsibilities for the SB 884 program and ensure that cost recovery under the program is supported by sufficient information regarding risk reduction, reliability benefits, cost efficiency, and comparison to alternative mitigations.

The Joint IOUs also provide estimates concerning the proposed decision's effect on the mileage and risk reduction associated with PG&E's recently filed EUP. These estimates were introduced after submission of this proceeding, were not subject to discovery or rebuttal, and differ from estimates presented in PG&E's earlier motion to amend the procedural schedule. We therefore give these estimates no evidentiary weight. In any event, the number of projects or miles that satisfy a utility's preferred methodology is not within the scope of this

proceeding and is not a statutory benchmark governing the Commission's review and conditional approval of EUP cost.

We further clarify that the requirements adopted in this decision govern BCRs and cost-recovery determinations made in connection with the SB 884 program. This decision does not, by itself, modify requirements applicable to a Risk Assessment and Mitigation Phase proceeding, general rate case, or other non-SB 884 proceeding. Any question concerning the relevance of the reasoning or methodological principles adopted here to another proceeding shall be resolved in that proceeding based on its scope, record, and governing law.

Per Rule 14.3(c), we give no weight to comments that fail to focus on factual, legal or technical errors, or merely re-argue a party's position, and therefore do not address those comments here.

14. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Regina DeAngelis is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

Background

1. The Commission first established the SB 884 program and its guidelines in Resolution SPD-15.

2. The Office of Energy Infrastructure Safety (Energy Safety) issued its own guidelines on February 20, 2025, titled *10-Year Electrical Undergrounding Plan Guidelines* (*Energy Safety EUP Guidelines*).

3. After Energy Safety released its *Energy Safety EUP Guidelines* and established its four screens, the Commission further updated and refined the SB

884 Program and its guidelines in Resolution SPD-37. The Commission recognized in Resolution SPD-37 that "significant changes" could be made to the forecasted economic metrics (total costs, unit costs, and BCRs) of any undergrounding project as it moved through *Energy Safety EUP Guideline* Screens 1-4 and became more accurately scoped, especially as projects move through Screens 3 and 4.

Benefit-Cost Ratio Methodology

4. The Commission adopted the use of the BCR framework in R.20-07-013, the Risk-Based Decision-Making Framework (RDF).

5. The BCR framework developed in R.20-07-013 is not specific to wildfire and reliability risk; rather, it examines all utility risks, including those related to other safety issues.

O&M Costs and O&M Savings

6. The RDF (R.20-07-013) is silent on where O&M Savings should be placed in the denominator or numerator of the BCR calculation.

7. O&M Savings falls outside every operative definition the RDF supplies.

8. O&M Savings is not defined as a "Benefit" under existing definition of that term in the RDF (R.20-07-013) because the RDF definition covers only risk reduction measured by changes in Attribute levels and not avoided expenditures.

9. O&M Savings are not defined as denominator "cost" under the plain text of D.25-08-032, Appendix A, Row 25 because O&M Savings are not an "expense made necessary by the capital investment;" O&M Savings are the opposite—

representing O&M expenditures rendered *unnecessary* relative to the No-Build Baseline.

10. The Staff BCR White Paper shows that adopting the Joint IOUs' proposal (i.e., Method 1) fails under practical use cases, in that the proposal is "structurally incapable of handling high-savings projects (e.g., of handling substantial vegetation management displacement)."

11. The Staff BCR White Paper's recommended formula (Method 3 or the Disaggregated Formulation) involves disaggregating O&M Savings from O&M costs and placing the O&M Savings in the numerator (as a Benefit) and the O&M costs in the denominator (as a Cost), thereby avoiding situations where the denominator in the BCR becomes zero or negative.

12. Placing O&M Savings in the numerator, as part of the Total Benefit, follows from the RDF's (R.20-07-013) own text: where D.25-08-032, Appendix A, Row 25 directs that the numerator "reflect the full set of Benefits that are the results of the incurred costs."

13. Limiting benefits to risk reduction alone is inconsistent with SB 884, which directs that project prioritization be based on both risk reduction and cost-efficiency.

14. A risk-only focus in the BCR numerator could crowd out cost-efficient opportunities within a constrained budget.

15. O&M Savings "result" from incurred capital costs.

16. O&M Savings only arise after the mitigation is built.

17. O&M Savings are not a capital "cost offset;" they don't reduce the capital recorded to rate base.

18. "Costs" are resources that could have gone to other uses, and benefits are the monetized outcomes of the project.

19. Costs represent the resources consumed to implement a mitigation; benefits represent the results of the incurred costs.

20. O&M Savings are not a resource consumed; they only arise after the mitigation is implemented and are therefore a result of the investment, just as avoided wildfire risk is.

21. O&M Savings are expenditures rendered unnecessary relative to the No-Build Baseline, which leaves the textual argument for including them in the denominator—the argument that the RDF (R.20-07-013) states the denominator should include expenses "made necessary" by the capital investment—unpersuasive.

22. Placing O&M Savings in the numerator aligns with standard benefit-cost analysis, under which avoided costs are consistently treated as benefits, and is consistent with the federal and academic guidance the Staff White BCR Paper relies upon (e.g., Office of Management and Budget, Circular No. A-94, November 2023; U.S. Department of Transportation Benefit-Cost Analysis Guidance for Discretionary Grant Programs, May 2025; and Boardman et al, Cost-Benefit Analysis: Concepts and Practice, 5th ed., Cambridge University Press, 2018).

23. Of the three methods presented, the Disaggregated Formulation (Method 3) is the only structurally robust option: it alone remains mathematically valid across all cost and risk conditions.

24. Only the Disaggregated Formulation (Method 3) avoids both negative and zero denominators, making it stable not just for undergrounding but for evaluating BCRs consistently across capital-intensive and low-capital mitigations alike.

25. O&M costs should be defined as the incremental "additional O&M expenditures required by the project or mitigation relative to the No-Build Baseline" and the RDF (R.20-07-013) locates that component of O&M cost in the denominator of the BCR ratio, directing that "[f]or capital programs, the costs in the denominator should include incremental expenses made necessary by the capital investment."

Risk Scaling

26. The Commission has yet to adopt any particular risk scaling function; and, until R.26-04-016 or another Commission proceeding adopts a particular risk scaling function, the RDF currently *requires* utilities to present BCRs using risk-neutral values and *allows* them to, additionally, and at their own discretion, also present BCRs using risk scaling functions of their own design.

27. One of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects.

28. Resolution SPD-37 directed the utilities to detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications.

29. The Joint IOUs' proposal on risk scaling cannot meet the directives in Resolution SPD-37 because the proposal would have each utility apply its own independently developed risk-averse, scaled function, which would not promote

the "comparability, transparency, and traceability in BCR calculations across large electrical corporations" that Resolution SPD-37 requires.

30. Establishing risk scaling guidance in a Phase 2 Application proceeding of the SB 884 program may not be practical because resolving any party disagreements on risk scaling functions during any expedited Phase 2 Application proceeding, across nine months, where the large electrical corporation will be seeking conditional approval of the costs for a 10-year electric undergrounding plan is not the appropriate venue for making such decisions.

ICE Calculator

31. The SB 884 program is limited to circuit segments located in a Tier 2 or 3 HFTD or a wildfire rebuild area.

32. An objective of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects, as supported by the directive in Resolution SPD-37 to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."

33. A "Blended VOS" for the ICE Calculator could serve to monetize the reliability consequences at specific locations (e.g., circuit, feeder, circuit segment) impacted by a reliability risk event.

34. The *SB 884 Project List Data Requirements Guidelines* require distinctions based on HFTD: Table 6 requires data for every ICE Calculator input for HFTD Region and specifies the residential and non-residential dollar values per customer-minute interrupted for each HFTD Region.

35. A system-wide VOS (as opposed to distinguishing between HFTD and non-HFTD regions) will overstate reliability risk in locations that experience longer duration outages, e.g., HFTDs.

36. Because SB 884 projects will be implemented in HFTDs and wildfire rebuild areas, the measuring of the reliability benefits produced by such projects should distinguish between the Value of Service to customers residing in HFTDs and those residing outside the area.

37. While the ICE Calculator is based on a national, pooled set of surveys that results in customer damage functions that estimate interruption costs for residential and nonresidential customers, because constructing and operating the model are distinct actions, nothing about the survey's customer sampling dictates whether inputs must be system-wide, as opposed to HFTD-specific.

Discount Rate

38. Discount rates are another necessary component of any BCR as they account for the time-value of money and put future costs and future benefits in present-day dollars.

39. Discount rates allow for comparisons both between costs and benefits within a risk mitigation as well as comparisons across risk mitigations.

40. An objective of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects, as supported by the directive in Resolution SPD-37 to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."

41. Because the discount rate is an analytical assumption that directly determines present value of costs and benefits used in the BCR calculation, utility-specific selection of a discount rate scenario could mean differences in estimated BCRs across large electrical corporations are driven not by differences in underlying system risk or mitigation effectiveness, but rather by differing choices of discount scenario assumptions.

42. The RDF (R.20-07-013) allows the utilities to state their preference for one of the three discount rates; it does not provide for outright choice when it comes to ratepayer funding for any risk-based decisions.

43. If each utility chose its own discount rate, the "comparability, transparency, and traceability in BCR calculations across large electrical corporations" required by Resolution SPD-37 would not be promoted.

44. The RAMP and general rate case filings evaluate mitigations at the program level, rather than the project level which is relied upon in the SB 884 program.

45. Because a BCR-related threshold has already been established for the Phase 2 Application stage (wherein all BCRs of submitted projects must be greater than or equal to 1), were the Commission *not* to choose a common discount rate in this proceeding, then any large electrical corporation participating in SB 884 program would, in effect, when submitting its Phase 2 Application, be submitting up to three distinct EUPs.

46. Ratepayers pay utility revenue requirements through rates rather than direct costs, and for capital undergrounding projects the revenue requirement

substantially exceeds direct costs because it includes the authorized return on debt and equity, taxes, and other loaders.

47. Because the BCR operates as a gating condition on project submission and cost recovery from ratepayers, the discount rate analysis should be conducted at the rate ratepayers in fact bear.

Backcasting

48. Backcasting is described in Resolution SPD-37 as a method for recalculating BCRs and unit costs using updated Risk Reporting Unit (RRU) structures and risk model inputs to establish a bridge between prior inputs and new inputs, to ensure an 'apples-to-apples' comparison.

49. Resolution SPD-37 and the *Energy Safety EUP Guidelines* require some type of backcasting, with differences based on whether backcasting is conducted at the circuit segment level, at the subproject level, or the RRU level.

50. Since the Phase 2 Conditions for the SB 884 program for balancing account treatment necessitate comparisons between actual, recorded BCRs and original, forecasted BCRs, a means for a granular apples-to-apples comparison is needed.

51. Adopting the utility proposal to backcast at the same level of detail as the original analysis, meaning that if the BCR was calculated for a project chosen at the circuit segment level any future backtesting for that project should only be performed at the circuit segment level to avoid misalignment between comparisons, would not allow for a granular apples-to-apples comparison.

52. An apples-to-apples comparison between original and updated project evaluations is critical to assessing changes in project cost-effectiveness over time.

53. Conditioning backcasting on subjective utility determinations would contradict the directive in Resolution SPD-37 to promote "comparability, transparency, and traceability in BCR calculations across large electrical corporations."

54. A change in a risk model or model input may change a calculated BCR without a corresponding change in project scope, project cost, physical performance, or expected mitigation effectiveness. Backcasting must distinguish changes attributable to the model or its inputs from changes attributable to the project.

Net Salvage Value

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

56. In the absence of the use of net salvage value, electric undergrounding could result in the abandonment of infrastructure, such as old poles, which would become “stranded costs” borne by other parties rather than the utilities.

57. It is not sufficient to only include direct project costs, since projects also include indirect costs and these indirect costs include end-of-life costs represented by net salvage value.

58. The true costs of undergrounding projects can only be captured through the inclusion of indirect costs in the BCR calculation, and that net salvage value should be part of that calculation.

Present Value Revenue Requirement

59. Present Value Revenue Requirement (PVRR) is a financial metric used by utilities in rate cases and long-term planning to evaluate the cost of investments or programs over the life of the asset.

60. The revenue requirement is the full cost to be funded by ratepayers.

61. Providing a PVRR is currently optional under the *SB 884 Project List Data Requirements Guidelines*.

62. PVRR includes all project costs, such as the capital investment, incremental O&M, and net salvage value, and is calculated by adding up the costs for each year of the project, determining the revenue required to compensate for the costs, and then discounting back to the base year. O&M Savings are not included in the PVRR; they are reflected in the BCR numerator.

63. If the PVRR, as opposed to capital costs, is used to represent costs in the denominator of the BCR calculation, the true cost of mitigation will be more accurately represented.

Definition of Year Zero

64. This proceeding considers whether to define BCR Year Zero as follows: the year a project becomes "used and useful," which serves as the reference year for discounting both costs and benefits.

65. The Joint IOUs' alternative proposal is that BCR Year Zero be defined as the year that a utility's 10-year electric undergrounding plan becomes effective, meaning the year a utility begins recording project costs to the balancing account.

66. The alternative proposal by the Joint IOUs, which relies on a single effective-year, defeats the very purpose of the metric, meaning the timing effect the Joint IOUs seek to remove is precisely what the BCR should capture.

67. By defining the BCR Year Zero as the year a project becomes "used and useful," the adopted methodology aligns the timing of discounted costs and benefits with the project's actual in-service date.

68. A used-and-useful anchor ties each project's discounting to the year it actually begins delivering benefits, preserving the schedule differences that distinguish a fast project from a slow one.

Baseline Scenario for Reference Conditions to Compare BCR

69. In the context of a BCR, the Baseline Scenario represents “the reference conditions against which all benefits and costs are measured.”

70. The Staff BCR White Paper recommends a specific Baseline Scenario to promote consistency, referred to as the No-Build Baseline Scenario.

71. Consistent baseline treatment and clear identification of individual components are foundational to a robust BCR framework.

72. In this proceeding, different opinions exist on whether mitigations, such as EPSS and PSPS, should be reflected in the No-Build Baseline.

73. Resolution SPD-37 specifies that "No-Build Baseline represents a well-defined baseline scenario of the status quo that describes expected conditions in the absence of any new project or Risk Reporting Unit (RRU) implementation."

74. The Staff BCR White Paper describes the No-Build Baseline Scenario, in part, as follows: “The No-Build Baseline establishes the current risk profile of the system, incorporating all infrastructure and risk controls that are already funded,

approved, or implemented (*e.g.*, existing VM [Vegetation Management] and inspection cycles)."

75. The Staff BCR White Paper recommends the No-Build Baseline as the single, uniform, and most comprehensive reference against which all four components are calculated, to promote consistency across projects and utilities.

Audit - Audit of Costs Recorded to Balancing Account

Process to Review Compliance to Primary and Secondary Objectives

76. With some exceptions, the audit process proposed by the Joint IOUs does not reasonably address the need for an audit process to confirm compliance with the Primary and Secondary Objectives for the recorded costs in the balancing account, as directed in Resolution SPD-37.

77. With some exceptions, the audit process proposed by the Joint IOUs does not provide a reasonable level of certainty to all stakeholders in terms of how the process will be implemented.

Verifying the Audit's Primary Objectives

Confirm Cost Cap Amount

78. As part of the audit, the auditor will verify that the total annual costs recording the balancing account did not exceed the approved cost cap for a given year (Phase 2 Condition #1).

Third Party Funding

79. As part of the audit, the auditor will verify whether third-party funds were received and how such funds were applied and accounted for in the utility's internal systems (Phase 2 Condition #2).

Average Recorded Unit Cost and BCR Methods

80. As part of the audit, the auditor will verify that the average, actual unit costs for all projects completed in any given two-year period do not exceed some approved average unit cost (to be determined by the Phase 2 Application decision) (Phase 2 Condition #3).

81. Resolution SPD-37 defines the average recorded unit cost as cost "per mile of undergrounding performed," yielding the aggregate as the total recorded undergrounding cost divided by the total miles undergrounded across all completed projects.

Compliance with Annual Cost Cap for Balancing Account

82. The Joint IOUs propose that three Phase 2 Conditions established in Resolution SPD-15 (Phase 2 Conditions #1, #3, and #4) be revised to include a 2% variance threshold before IOUs are required to record individual project costs to the memorandum account in Phase 3 and justify this proposal as consistent with the 15% variance threshold previously approved for PG&E's system hardening costs in its 2020 GRC.

83. As previously established by the Commission in Resolution SPD-37, no variance was included in such Phase 2 Conditions (i.e., the cost cap, unit costs, and BCR conditions).

84. Since, in the SB 884 program, each large electrical corporation will have the opportunity to recover amounts accrued above the balancing account caps through the separate Phase 3 memorandum account process, adding variances to the Phase 2 Conditions is not needed.

Verifying the Audit Secondary Objectives

85. The Secondary Objectives of the audit are: (1) verifying project costs recorded to the balancing account tie to projects that are used and useful (Used and Useful Requirement); and (2) verifying the incrementality showing found in Application Requirement No. 2 (i.e., that recorded costs in the balancing account do not duplicate any costs already authorized by another Commission decision, mechanism, or those received from a third party (Incrementality Requirement)).

Used and Useful Requirement

86. To qualify for inclusion in the balancing account, costs must tie to infrastructure that is "used and useful."

87. The proposal by the Joint IOUs that the "audit year" be defined by the auditor is not adopted because the proposal is not consistent with Resolution SPD-37 that clarifies that each EUP Audit shall review EUP projects that become "used and useful" during the 12-month period covered by the audit.

Incrementality Requirement

88. The audit will confirm that recorded costs in the balancing account for undergrounding projects and/or subprojects are not also included in a utility's general rate case or other proceeding.

89. At a high level, the Joint IOUs propose a structure for auditing the incrementality of projects that consists of looking at the previous general rate cases and comparing it against a list of projects submitted by the Joint IOUs.

Additional Audit Objectives

90. Five additional Phase 2 Conditions (Phase 2 Conditions #6 through #10) are adopted in this decision.

91. While Resolution SPD-37 found that the "Primary Objective" of the SB 884 program audit is to determine, after costs are recorded to the balancing account, whether such costs do, in fact, meet the Phase 2 Conditions, this decision does not adopt a methodology for verifying whether a large electrical corporation satisfies these five new Phase 2 Conditions.

Audit Framework – Project Level

92. The SB 884 program is largely based on an analysis of project-level information, rather than portfolio-level information.

93. Symmetry between project approval and subsequent auditing will improve transparency and facilitate comparisons between approved forecasts and actual project performance.

Auditor Selection

94. A comprehensive audit framework inherently includes the selection of the audit team, mandating that auditor selection criteria evaluate both objectivity and technical competence to fulfill the audit objectives.

95. A process for the selection of an auditor should be adopted as part of this proceeding because the timeline for resolving a proceeding initiated by a utility for review of a 10-year electric undergrounding plan is compressed, set at nine months, so that any process regarding the selection of an auditor that can be put in place now will facilitate the expeditious resolution of any future proceedings within the nine-month timeframe.

Audit Standards

96. The Joint IOUs propose that the audit be conducted under the American Institute of Certified Public Accountants (AICPA) Consulting Standards because:

(1) AICPA provides for flexibility to accommodate unique circumstances, such as those presented under SB 884; (2) the AICPA is designed for commercial entities, such as the utilities, while other standards, such as the Generally Accepted Government Auditing Standards, are primarily focused on government entities; and (3) the AICPA provides comprehensive guidance for performing consulting engagements and reflects recognized professional practices, such as objectivity, competency, and due professional care.

97. The Generally Accepted Government Auditing Standards govern third-party audits of government entities and are also used for audits of entities that receive public or ratepayer funds.

Single Audit Report

98. The Joint IOUs recommend a single report structure to promote efficiency.

Auditing the Benefits

99. The Joint IOUs state that "[t]he Auditor should only audit costs (denominator) in the BCR calculation and not the risk reduction benefits (numerator)" because "it is not possible for the utility to provide the actual risk reduction achieved."

Meaning of Audit Report

100. For purposes of the SB 884 program, the meaning of the term "audit report" is clarified.

Additional Phase 2 Conditions

101. Phase 2 Conditions provide the intended cost containment controls and ratepayer protections necessary for the Commission to determine whether the costs of an EUP should be approved as just and reasonable.

102. Resolution SPD-15 established Phase 2 Conditions #1 through #5 because the SB 884 program is unique in that costs are potentially "conditionally approved" within the program across a 10-year time frame.

103. After the Commission established five initial Phase 2 Conditions in Resolution SPD-15, Energy Safety issued its own review process that includes filtering potential undergrounding projects through four increasingly specific screens (*Energy Safety EUP Guidelines* Screens 1, 2, 3, and 4).

104. Each screen in the *Energy Safety EUP Guidelines* reduces the uncertainty associated with any project's forecasted costs and benefits, as it moves towards becoming "fully scoped."

105. Additional Phase 2 Conditions are needed given the large uncertainties associated with the Phase 2 Application cost forecasts, as recognized in Resolution SPD-37.

Adoption of Additional Phase 2 Conditions

106. The large majority of projects that the Commission will review in a Phase 2 Application will have only passed through *Energy Safety EUP Guidelines* Screen 2.

107. As stated in Resolution SPD-37, the large majority of forecasted data available to the Commission at the time a Phase 2 Application is filed will not be sufficiently precise to provide the intended cost containment controls and ratepayer protections anticipated in Resolution SPD-15.

108. Only after projects move through the *Energy Safety EUP Guidelines* Screen 4 do cost estimates become materially more certain.

109. The *Energy Safety EUP Guidelines* Screen 4 estimate is the most mature forecast available before construction.

110. While information regarding alternative mitigations is provided to Energy Safety and the Commission through the existing data requirements, the Commission will have no means of protecting ratepayers from instances where undergrounding is selected over a more cost-effective alternative without Phase 2 Conditions that ties to alternative mitigations.

111. The importance of comparing undergrounding to alternative mitigations is found in subsection (c) of Section 8388.5.

112. The SB 884 program is unique in that costs are potentially "conditionally approved" within the program across a 10-year time frame.

113. The Phase 3 memorandum account process established in Resolution SPD-15 exists to address the inherent uncertainties associated with planning across a 10-year time frame.

114. Costs incurred to execute the EUP that do not meet the Phase 2 Conditions can potentially be recorded in the Phase 3 memorandum account.

115. At the project-level, a project's forecasted economic metrics should be compared to its actual performance after the project is implemented.

116. The additional Phase 2 Condition #8 and Phase 2 Condition #9 represent reasonable versions of the project-level quantitative conditions that the Commission directed to be considered in the instant Application for comparing actual BCRs and unit costs to forecasted BCRs and unit costs.

117. The 30% threshold in additional Phase 2 Conditions #8 and #9 represents a reasonable cost-containment threshold that leaves reasonable room for execution risk (as the utilities move projects from *Energy Safety EUP Guidelines* Screen 4

through implementation) while also ensuring that material departures from Screen 4 forecasts are not recovered through the balancing account.

118. The additional Phase 2 Condition #10 brings forward the existing Phase 2 Application Requirement that only projects with BCRs greater than or equal to 1 may be included in the Phase 2 Application to the *Energy Safety EUP Guidelines* Screen 4 stage.

Consideration of Other Factors in Selecting Mitigation Alternatives

119. Consideration of other local factors outside the BCR is unnecessary under the SB 884 process and, in addition, (1) PG&E already captures ingress/egress risk in its Wildfire Consequence Model v4 through the AFN (egress) and Terrain Difficulty Index (ingress); (2) PG&E already incorporates granular PSPS lookback data into the BCR as well; and (3) SDG&E applies an ingress/egress multiplier in its consequence model and models vegetation contact at the span level within the BCR.

120. Deriving the proposed uncertainty factor of 30% from the Association for the Advancement of Cost Engineering (AACE) ranges, which apply to capital-cost estimating, seems more appropriate for addressing uncertainty in realized construction costs than modelling uncertainty.

121. The Joint IOUs proposal for consideration of other factors in selecting a mitigation is asymmetric, in that it only ever operates to keep undergrounding projects in consideration, as it operates exclusively to relax the BCR threshold for undergrounding relative to alternative mitigations.

122. The Joint IOUs proposal for consideration of other factors in selecting a mitigation conflicts with the intent of the additional Phase 2 Condition #6 which

requires that all undergrounding costs recorded to the balancing account be associated with a project whose forecasted BCR is at least as high as the forecasted BCR of the best-performing alternative.

Incorporating Previously Scoped Projects

123. Costs of undergrounding projects that a large electrical corporation scoped, or that were authorized and funded, before the effective date of its EUP may be recorded to the EUP balancing account only if the large electrical corporation demonstrates that: (1) the miles and costs for which it requests EUP recovery are incremental to all undergrounding miles and costs authorized or recovered in any general rate case or other cost recovery proceeding, consistent with Application Requirement No. 2 and Phase 2 Conditions #1 through #4 of Resolution SPD-37, and the additional conditions (Phase 2 Conditions #6 through #10) adopted in this decision, and (2) any previously authorized scope, or portion thereof, is reflected in the no-build baseline, with that scope's mileage and associated risk-reduction benefits excluded from the BCR and unit cost calculations.

Conclusions of Law

Background

1. It is reasonable to adopt additional cost containment controls and ratepayer protections to ensure the Commission has the information needed to determine the appropriateness of cost recovery for an EUP.

Benefit-Cost Ratio Methodology

2. Because the RDF (R.20-07-013) neither classifies O&M Savings as a benefit or cost, nor does it direct where they belong in the ratio, it is reasonable to find

that the RDF (R.20-07-013) leaves a definitional gap that this proceeding must resolve.

3. It is reasonable to adopt the Method 3 or the Disaggregated Formulation where: (1) O&M Costs are added to the denominator (as a cost), and O&M Savings are added to the numerator (as a benefit); and where (2) large electrical corporations shall separately report, for each project or RRU, the baseline O&M expenses under the No-Build Baseline, the O&M Savings, and the incremental O&M Costs used in the BCR calculation.

4. With respect to the methodology for accounting for O&M Savings and O&M costs in the BCR, and in relation to Total Capital Costs, it is reasonable to adopt the following relationship and require that this be used in connection with BCR's calculated in connection with the SB 884 program:

$$BCR = \frac{Risk\ Reduction\ Benefits + O\&M\ Savings}{Capital\ Costs + O\&M\ Costs}$$

5. It is reasonable to define O&M Savings as the avoided O&M expenditures associated with the No-Build Baseline that are eliminated by the project or mitigation.

6. It is reasonable to define O&M costs as the incremental additional O&M expenditures required by the project or mitigation relative to the No-Build Baseline.

Risk Scaling

7. It is reasonable to require each large electrical corporation to use the same risk scaling approach within the context of the SB 884 program because one of the stated objectives of this proceeding is to establish a "standardized methodology" for evaluating undergrounding projects and based on Resolution SPD-37's directive to "detail at least one standardized and consistent methodology for evaluating and comparing the cost-efficiency of undergrounding and alternative mitigations in SB 884-related applications."

8. It is reasonable that unless and until the Commission explicitly adopts an alternative risk scaling function in the recently opened RDF proceeding (R.26-04-016) or another future proceeding the single approach to be used in connection with any EUP will be unscaled (i.e., risk-neutral) risk values.

9. It is reasonable that if the Commission does decide in the new RDF proceeding (R.26-04-016) or another future proceeding to adopt another risk scaling function, then an EUP or Phase 2 Application filed or submitted thereafter may instead choose to use the Commission-adopted risk scaling function.

ICE Calculator

10. For the purposes of the SB 884 program, it is reasonable for the large electrical corporations to use the ICE Calculator Version 2.0 to determine a standard dollar value of electric reliability risk until the utility has time to fully review and evaluate the new information in the ICE Calculator 2.1, and to then incorporate the new version into its risk models and mitigation decision-making tools.

11. Coordinating the integration of the ICE Calculator 2.1—and any new updates to the ICE Calculator during the Commission's consideration of any future 10-year electric undergrounding plans and possibly longer —with risk model "version" changes, as defined in the *Energy Safety EUP Guidelines,* is reasonable.

12. For the purposes of the SB 884 program, it is reasonable for the large electrical corporations to use two ICE Calculator values (distinguishing between HFTD and non-HFTD regions) for each customer class (residential and non-residential) across large electrical corporation's service territory (i.e., four total Value of Service be produced).

13. For projects located in a Tier 2 or 3 HFTD, it is reasonable to use HFTD-region $/CMI (Customer Minute Interruption) values consistent with Table 6 of the Project List Data Requirements in the BCR reliability calculation. For projects located in a Wildfire Rebuild Area outside a Tier 2 or 3 HFTD and for spans outside the HFTD boundary included under *Energy Safety EUP Guidelines* § 2.4.3.1, it is reasonable for the large electrical corporations to use the corresponding $/CMI (Customer Minute Interruption) values (HFTD or Non-HFTD, residential or non-residential).

14. It is reasonable to monetize reliability consequences at specific locations impacted by a reliability risk event and to use the ICE Calculator at each location to get a "blended VOS" but also that such "blended VOS" shall be calculated at the RRU level.

15. Because the SB 884 program is limited to circuit segments located in a Tier 2 or 3 HFTD or a wildfire rebuild area, it is reasonable to find that the Value of

Service values used to monetize reliability benefits in the BCR by the ICE Calculator should be derived from the eligible area customer population (rather than, as the Joint IOUs' propose, the system-wide customer population).

Discount Rate

16. Within the unique context of the SB 884 program, it is reasonable to require large electrical corporations to rely on a single, common discount rate scenario— the WACC rate— for all uses of the BCRs in connection with the SB 884 program, including, but not limited to EUPs, applications, Phase 2 Conditions, ongoing reporting requirements, etc.

17. In the SB 884 program context, it is reasonable to find that (1) a single, common discount rate must be chosen, at the very latest, by the time the Commission issues its Phase 2 Application decision and thereby finalizes the Phase 2 Conditions (as the discount-rate will directly impact any BCR threshold that is tied to any Phase 2 Condition), and (2) that choosing this common discount rate now, as opposed to after a large electrical corporation submits its Phase 2 Application, will significantly facilitate the ability to resolve a Phase 2 Application within the nine-month statutory timeline.

18. The appropriate common discount rate to apply to the SB 884 program is the WACC rate, on the grounds that ratepayers both bear the costs and receive the benefits of undergrounding.

19. It is reasonable to require large electrical corporations to use the WACC rate for all BCRs presented to the Commission, at any point, in connection with the SB 884 program.

20. It is reasonable to require that, for the purposes of the SB 884 program, large electrical corporations use a single discount rate for both numerator and denominator is appropriate to avoid biasing the BCR.

Backcasting

21. It is reasonable to retain the Resolution SPD-37 definition of backcasting, recalculating BCRs, and unit costs using updated RRU structures and risk model inputs, and require that backcasting be performed at the RRU or subproject level, consistent with the RDF (R.20-07-013).

22. Consistent with the RDF (R.20-07-013), it is reasonable to require that backcasting also recalculate pre-mitigated risk, post-mitigated risk, and total mitigation benefit, as well as the O&M Costs and O&M Savings underlying the BCR, so that both sides of the BCR are restated on the new reporting unit.

23. Without backcasting, as adopted herein, it is reasonable to find that a change in the reported BCR (i.e., where the actual BCR of a project differs from its Phase 2 Application forecast BCR) could reflect either (i) a genuine change in project scope, cost, or risk, or (ii) merely a change in how the project was subdivided or modeled.

24. Without backcasting, as adopted herein, it is reasonable to find that the Commission and parties would be unable to tell what drove the change in the BCR from forecast to actual. It is reasonable that backcasting identify and reconcile the effects of changes in project scope, reporting structure, risk models, and model inputs. Backcasting does not replace the forecast or benchmark specified in an applicable Phase 2 Condition, and a change in a risk model or model input occurring after a project has entered construction, standing alone,

shall not establish noncompliance with a Phase 2 Condition. Where a large electrical corporation contends that a difference between forecasted and actual values is attributable to such a change in a risk model or model input, it bears the burden of demonstrating that effect, including by reporting, for comparison purposes only, the actual BCR calculated under the risk model version underlying the Screen 4 forecast.

Net Salvage Value

25. It is reasonable to require that net salvage value be accounted for at the project level as part of the PVRR cost treatment expressed as the Cost element in the BCR because omitting net salvage from costs will lead to an underestimate of project costs, inflating the BCR. It is also reasonable to require that net salvage be reflected once, and only once, in the PVRR; where net salvage or removal costs are already reflected in the project's PVRR (*e.g.*, through a large electrical corporation's depreciation rates, group-accounting treatment, a PVRR multiplier, or another component of the PVRR), the large electrical corporation shall identify and quantify that treatment to the extent reasonably practicable and shall not separately add the same costs.

26. It is reasonable to find that, in the absence of the use of net salvage value, electric undergrounding could result in the abandonment of infrastructure, such as old poles, which would become "stranded costs" borne by other parties rather than the utilities.

Present Value Revenue Requirement

27. It is reasonable to require large electrical corporations to use the PVRR for BCR calculations but if the utilities do not have a PVRR for the mitigation project, the utilities are required to make a best estimate using available data.

Definition of BCR Year Zero

28. It is reasonable to adopt the definition of BCR Year Zero as the year a project becomes "used and useful," the single, project-specific reference year to which all of that project's costs and benefits are discounted because this definition ties each project's discounting to the year it actually begins delivering benefits, preserving the schedule differences that distinguish a fast project from a slow one.

Baseline Scenario for Reference Conditions to Compare BCR

29. It is reasonable to adopt the No-Build Baseline as a single, well-defined reference condition and require that every component of the BCR be measured against it.

30. The No-Build Baseline should be defined as the status quo of the existing system, the expected conditions in the absence of any new project or RRU, incorporating all infrastructure, mitigations, and risk controls that are already funded, approved, or implemented (e.g., current O&M, vegetation management and inspection cycles, PSPS, EPSS and fast-trip programs).

31. It is reasonable that all determinations made in this decision as to how to calculate the BCR be applicable to all BCRs presented to the Commission at any point in connection with the SB 884 program.

Audit - Audit of Costs Recorded to Balancing Account
Process to Review Compliance to Primary and Secondary Objectives

Verifying the Audit's Primary Objectives
Confirm Cost Cap Amount

32. As this matter was uncontested, it is reasonable to adopt a methodology of verifying Phase 2 Condition #1, where the cost cap amount is to be confirmed by the auditor based on the value adopted in the Phase 2 Application decision.

Third Party Funding

33. It is reasonable to adopt a three-step audit process for Phase 2 Condition #2: (1) the utility affirmatively states in writing whether any third-party funding was received in the audit year; (2) if funding was received, the auditor independently reviews the terms of that funding to determine whether it is eligible to offset the cost cap; and (3) the auditor then reviews the utility's books and records to confirm that any eligible funding was actually applied to reduce the cap.

Average Recorded Unit Cost and BCR Methods

34. Because Resolution SPD-37 defines the average recorded unit cost as cost "per mile of undergrounding performed," yielding the aggregate as the total recorded undergrounding cost divided by the total miles undergrounded across all completed projects, for Phase 2 Condition #3, it is reasonable to find that no separate method or auditor discretion is needed.

35. It is reasonable to adopt the definition in Resolution SPD-37 for average recorded unit costs for the auditing of Phase 2 Condition #3.

36. With respect to Phase 2 Condition #4, it is reasonable for the auditor to verify that the average, actual BCR for all projects completed in any given two-

year period does not fall below some approved average BCR (to be determined by the Phase 2 Application decision).

37. For Phase 2 Condition #4, it is reasonable to adopt the Joint IOUs' refined proposal for calculating the average recorded BCR (as total recorded benefits divided by total recorded costs for all projects, or Subprojects where the Subproject Designation is elected, that became used and useful in the two-year period (the economically consistent aggregation of a benefit-cost ratio, which weights each project's BCR (or Subproject's BCR) by its actual cost and benefit and requires no proxy)).

38. It is reasonable to adopt the following definition for "Unit Cost": total recorded (or, for forecasts, total forecasted) capital and expense costs of a project, or of a Subproject where the Subproject Designation is elected, divided by the circuit miles of undergrounding installed.

39. It is reasonable to adopt the following definition for "Average recorded unit cost" in the two-year period: the sum of recorded costs for all projects (or Subprojects) that became used and useful in the two-year period, divided by the sum of circuit miles of undergrounding installed in those projects (or Subprojects).

Compliance with Annual Cost Cap for Balancing Account

40. It is reasonable not to adopt the Joint IOUs' proposal to revise Resolution SPD-15 to include 2% variance thresholds due to forecast uncertainty because the SB 884 program is different than the general rate case context and other avenues exist for cost recovery without a variance.

Verifying the Audit's Secondary Objectives

Used and Useful Requirement

41. For purposes of determining when certain projects and subprojects are considered used and useful (and therefore, which projects and subprojects are assigned to the audit each year), it is reasonable to adopt the definition of "used and useful" set forth in the *SB 884 Project List Data Requirements Guidelines*, which states that a project is "used and useful" when it is fully complete and providing service to customers.

42. It is reasonable to require that any circuit segments that are deemed used and useful (based on this definition) in a given year must be included in the audit covering that same given year.

43. Where a utility elects the Subproject Designation, it is reasonable that the audit will be performed at the subproject (RRU) level.

44. It is reasonable that each project (or subproject) will be included in the audit covering the year it becomes used and useful and compared against its backcasted values; recorded costs and benefits for each subproject must be traceable to, and reconciled with, the project from which the subproject was designated.

Incrementality Requirement

45. As this matter was uncontested, it is reasonable to adopt the Joint IOUs' proposal with a clarification, meaning the audit should determine incrementality, at a high level, by comparing general rate case-authorized (or other Commission-authorized) undergrounding mileage completed (not just amounts spent) against proposed mileage in the EUP.

Additional Audit Objectives

46. Consistent with Resolution SPD-37, it is reasonable to find that a methodology for verifying compliance with the five new Additional Phase 2 Conditions is needed.

47. It is reasonable to require any large electrical corporation that files a Phase 2 Application to, in that Phase 2 Application, include a proposed methodology for verifying whether it satisfies each of the five new Additional Phase 2 Conditions; and that where more than one large electrical corporation files a Phase 2 Application, the proposed methodologies should be consistent, and any difference shall be identified and justified. Once adopted in the Phase 2 Application decision, the verification methodology shall be applied within the audit methodology framework adopted in this decision, including audit at the RRU level and comparison against backcasted values as set forth in Conclusions of Law 49 through 52.

Audit Framework – Project Level

48. The proposal by the Joint IOUs for the auditor to perform a statistically appropriate level of sampling at the portfolio level to confirm that costs are properly recorded to the one-way balancing account should not be adopted because the SB 884 program is largely based on an analysis of project-level information, rather than portfolio-level information.

49. To ensure consistency across the SB 884 program, it is reasonable that the audit be performed at the Risk Reporting Unit (RRU) level, as the RRU is the most granular unit at which risk, cost, and BCR are reported.

50. Where a large electrical corporation does not elect the Subproject Designation, it is reasonable to find that the RRU is the "project," and the audit will be performed at the project level.

51. Where a large electrical corporation elects the Subproject Designation, it is reasonable to find the RRU is the Subproject, and the audit will be performed at the Subproject level.

52. It is reasonable to include each project (or subproject) in the audit for the year it becomes used and useful, with the audit comparing actual results against the RRU's forecasted values, backcast as required in Section 5.5 to reflect the current RRU structure and any updated risk models or risk model inputs.

53. For purposes of the audit, it is reasonable to find that recorded costs and benefits for each project (or subproject) must be traceable to, and reconciled with, the project from which the subproject was designated.

Auditor Selection

54. It is reasonable to promote the expeditious resolution of any future proceedings under the SB 884 process, and because the selection of an auditor inherently includes selection of an audit team, the Joint IOUs should submit via Tier 2 Advice Letter within 45 days of the effective date of this decision, a list of auditors qualified to perform this audit, together with a description of how the auditors meet the Audit Standards, set forth below.

Audit Standards

55. It is reasonable to require that audits be conducted in accordance with Generally Accepted Government Auditing Standards because these standards

govern third-party audits of government entities and are also used for audits of entities that receive public or ratepayer funds.

Single Audit Report

56. It is reasonable to adopt a single audit report structure with the single audit report covering all Phase 2 Conditions and the used and useful and the incrementality showings.

57. It is reasonable to direct the large electrical corporations to file the audit report in the application proceeding initiated by the utility for approval of its 10-year electric undergrounding plan, with the report accepted for filing even if the proceeding is closed and parties being permitted to file comments in response to the report.

Auditing the Benefits

58. It is reasonable to audit the benefits in the BCR because the process is feasible and will enhance the transparency of the SB 884 process.

59. It is reasonable to require that, if the circuit segments actually undergrounded differ from those identified in the forecast presented in the Phase 2 Application, the large electrical corporation must recalculate its risk value benefits for the actually, as-built segments using the risk model version and inputs applicable under the backcasting methodology adopted in Section 5.5; it is also reasonable to require the large electrical corporation to provide the auditor with the recalculated risk values and supporting inputs.

Meaning of Audit Report

60. It is reasonable to find that in the context of the Commission's future review of any applications filed under the SB 884 process, that the scope of the

audit report is to confirm compliance with the Primary and Secondary Objectives (also referred to as Conditions).

Additional Phase 2 Conditions

61. It is reasonable to require additional Phase 2 Conditions to provide the intended cost containment controls and ratepayer protections necessary for the Commission to determine whether the costs of an EUP should be approved as just and reasonable.

Adoption of Additional Phase 2 Conditions

62. It is reasonable to adopt the five additional Phase 2 Conditions set forth below:

> **Phase 2 Condition #6**: All costs must be associated with a project whose forecasted undergrounding BCR (as presented in the Phase 2 Application proceeding) was at least as high as the forecasted BCR (as presented during the Phase 2 Application proceeding) of the best-performing alternative mitigation.
>
> **Phase 2 Condition #7**: Once any project passes through Energy Safety's Screen 4, if its fully scoped Energy Safety Screen 4 forecasted undergrounding BCR has fallen below the forecasted BCR of the best-performing alternative (as presented during the Phase 2 Application proceeding), then a large electrical corporation must re-evaluate the best-performing alternative using updated inputs consistent with those used for the Screen 4 undergrounding forecast and reconfirm that undergrounding project (as fully scoped and forecasted) remains at least as cost-efficient as the best-performing alternative.

Phase 2 Condition #8: Any project's actual BCR may not be more than 30% less than its fully scoped, Energy Safety Screen 4 forecasted BCR.

Phase 2 Condition #9: Any project's actual unit cost may not be more than 30% more than its fully scoped, Energy Safety Screen 4 forecasted unit cost.

Phase 2 Condition #10: Any project's fully scoped, Energy Safety Screen 4 forecasted BCR must remain at or above 1.

63. It is reasonable to adopt the additional Phase 2 Conditions #6 and #7 as they create conditions that will allow the Commission to protect ratepayers from instances where undergrounding is selected over a more-cost effective alternative, with the additional Phase 2 Condition #7 continuing the protection through *Energy Safety's EUP Guidelines* more accurate Screen 4.

64. It is reasonable to require, due to the large uncertainties associated with the Phase 2 Application cost forecasts and additional reasons, new project-level conditions (Phase 2 Conditions #6 through #10), to ensure costs booked to the balancing accounts are just and reasonable.

65. It is reasonable to adopt the additional Phase 2 Condition #8 and Phase 2 Condition #9 as versions of the project-level quantitative conditions that the Commission directed the Joint IOUs to consider in the instant Application for comparing actual BCRs and unit costs to forecasted BCRs and unit costs.

66. It is reasonable to adopt the applicable "forecast" to be used when applying Phase 2 Conditions #8 and #9 will be the *Energy Safety EUP Guidelines* Screen 4 forecast, which links to the AACE Class 4 estimate accuracy range,

which states deviations between the forecast and actuals should range from -30% to +50%.

67. It is reasonable to choose a 30% threshold for the additional Phase 2 Condition #8 and Phase 2 Condition #9, as 30% is modestly more restrictive than the upper bound of the AACE Class 4 estimate range. Furthermore, the same holds on the benefit side: with benefits held constant, a 30% decline in BCR corresponds to a cost increase of roughly 43%, which is also within the Class 4 upper bound.

68. It is reasonable to adopt the additional Phase 2 Condition #10 because it brings forward the existing Phase 2 Application Requirement that only projects with BCRs greater than or equal to 1 may be included in the Phase 2 Application to the *Energy Safety EUP Guidelines* Screen 4 stage.

Consideration of Other Factors in Selecting Mitigation Alternatives

69. It is reasonable to not adopt the recommendation by the Joint IOUs for permission when selecting mitigation alternatives to consider local factors outside risk models when forecasted BCRs for undergrounding projects are less than but within 70 percent of the BCRs forecasted for alternatives.

Incorporating Previously Scoped Projects

70. It is reasonable to find that the costs of undergrounding projects scoped or authorized and funded before the effective date of a EUP may be recorded to the EUP balancing account only if the utility demonstrates that: (1) the miles and costs for which it requests EUP recovery are incremental to all undergrounding miles and costs authorized or recovered in any general rate case or other cost recovery proceeding, consistent with Application Requirement No. 2 and Phase 2

Conditions #1 through #4 of Resolution SPD-37 and the additional conditions, the Phase 2 Conditions #6 through #10 adopted in this decision, and (2) any previously authorized scope, or portion thereof, is reflected in the No-Build Baseline with that scope's mileage and associated risk-reduction benefits excluded from the BCR and unit cost calculations.

71. It is reasonable to find that where the authorized undergrounding funding is established at a program or aggregate forecast level rather than by project, the incrementality demonstration shall be made against authorized program.

SB 884 Project List Data Requirements Guidelines and SB 884 Project List Data Template

72. The *SB 884 Project List Data Requirements Guidelines and SB 884 Project List Data Template* should be read consistent with the changes made herein.

Motions

73. This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are denied.

O R D E R

IT IS ORDERED that:

1. Large electrical corporations shall comply with the directives set forth in Resolution SPD-15 and Resolution SPD-37, together with the SB 884 Program: CPUC Guidelines, *SB 884 Project List Data Requirements Guidelines* and *SB 884 Project List Data Template*, each as revised herein, when filing a 10-year electrical underground plan pursuant to Public Utilities Code Section 8388.5(e)(1) for review and "conditional approval" of the plan's costs.

2. The large electrical corporations, as defined in Public Utilities Code Section 8388.5, shall submit a Tier 2 Advice Letter within 45 days of the effective date of this decision with a list of auditors qualified to perform the audit, together with a description of how the auditors meet the Audit Standards.

3. Application 26-02-005 is closed.

This order is effective today.

Dated November 19, 2026, at Sacramento, California.

JOHN REYNOLDS
President
DARCIE L. HOUCK
KAREN DOUGLAS
MATTHEW BAKER
CHRISTINE HARADA
Commissioners