PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON COMPANY
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SB-884 Resolution SPD-37 Joint IOU – Phase I
Application 26-02-005
Data Response

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Requesting Party:	The Utility Reform Network
Requester:	Reina L. Yanagiba
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SUBJECT: CBR CALCULATION METHODOLOGY, AUDIT METHODOLOGY, AND COST RECOVERY CONDITIONS UNDER SPD-37

The following data requests refer to the Joint Utility Application Requesting Commission Approval of Proposals for a CBR Calculation Methodology, Audit Methodology, and Cost Recovery Conditions as Specified in Resolution SPD-37. Please indicate for each response to which utility(ies) the response applies; if different for each utility, please provide for all utilities and specify to which utility the response applies.

QUESTION 001

Starting on page 4 the Joint Utilities recommend a benefit-cost ratio methodology.

a. Will the Joint Utilities use the same methodology to calculate BCRs? If not, please provide a table outlining the primary differences in the methodologies across IOUs.

b. What level of granularity (circuit level, project level, or something else) will BCRs be provided for?

    i. Will it be possible to calculate the BCRs of alternative mitigations (PSPS, EPSS, covered conductor, etc.) based on utility workpapers? Please explain.

c. Please provide an example calculation, for each IOU, of the methodology employed to calculate BCR using a real or example project. Please provide in Excel with all supporting workpapers and assumptions.

PG&E ANSWER 001

a. The Joint Utilities propose to use a common, standardized Benefit-Cost Ratio (BCR) calculation methodology that is aligned with the Commission-approved Risk-based Decision-making Framework (RDF). As described in the Joint Utilities Application, the proposed BCR methodology calculates the reduction in monetized risk (i.e., pre-mitigation risk minus post-mitigation risk) divided by the present value of mitigation costs.

While the overall structure and methodology are consistent across IOUs, certain utility-specific implementation variables may differ. For example, each utility may apply its own Commission-approved cost accounting frameworks and analytical practices. These differences do not alter the underlying BCR methodology but instead reflect how each IOU implements the common RDF.

To address the question of whether and how methodologies may differ within the common RDF-based BCR methodology, the Joint Utilities provide a comparative table below identifying key BCR framework elements and noting where utility-specific implementation may occur.

Table 1: Common RDF-based BCR Methodology and Utility-Specific Implementation Variables

BCR Framework Element (Common Across IOUs)	How This Element Is Applied / Where Utility-Specific Implementation May Occur
BCR Formula Structure	All IOUs calculate BCRs as the reduction in monetized risk (pre-mitigation risk minus post-mitigation risk) divided by the present value of mitigation costs, consistent with the RDF.
Risk Calculation	Each IOU applies its own risk models to estimate pre- and post-mitigation risk, consistent with the RDF.
Risk Categories included in Total Mitigation Benefit	All IOUs include enterprise risks consistent with the RDF (e.g., wildfire risk and reliability risk). The specific enterprise risks selected may reflect utility specific risk registers.
Risk Scaling	IOUs may differ in whether and how they apply risk-scaling, consistent with the RDF.
Cost Basis (including Cost Representation)	All IOUs will present results using the present value of mitigation costs, including capital costs and net O&M costs, consistent with the RDF. Utilities may differ in how those present-value costs are represented (e.g., PVRR-based or non-PVRR-based approaches), consistent with their individual accounting practices.

Discount Rate	Each IOU will provide all three discount rates, select one based on its preference, and apply it consistently to both benefits and costs.
ICE Calculator Granularity	All IOUs will use monetized reliability impacts using the ICE Calculator at a customer-class level, consistent with the Joint IOU Application.
BCR Year Zero	All IOUs will designate BCR Year Zero as the first year the Electric Undergrounding Plan (EUP) becomes effective, consistent with how utilities forecast costs and anchor cost analyses to the test year in GRCs.

b. BCRs will be provided at the project level (i.e., circuit segment level) consistent with the Energy Safety 10-Year EUP Guidelines.

   i. Yes. The Energy Safety EUP Guidelines require large electrical corporations to compare undergrounding projects to alternative mitigations as part of the Project Acceptance Framework. At multiple screening stages, utilities evaluate undergrounding relative to alternative mitigations and assess cost, risk reduction, and cost-benefit metrics at a common underlying level of analysis.

   Consistent with these requirements, the Joint Utilities' analyses are structured to support comparison of undergrounding and alternative mitigations using a consistent RDF-aligned framework. Where BCRs for alternative mitigations are calculated, those results are developed using the same underlying analytical structure that support EUP screening and are reflected in the project-level information required by the EUP Guidelines.

   The Joint IOU Application does not propose to expand or reformat BCRs for alternative mitigations beyond what is already required under the Energy Safety EUP Guidelines and Resolution SPD-37.

c. PG&E objects to this request as premature and unduly burdensome on the grounds that it seeks project-specific or illustrative BCR calculations prior to the EUP filing. Subject to and without waiving these objections, PG&E responds as follows:

   At this stage in our Joint IOU Application proceeding, detailed project-level cost estimates, final risk calibrations, and associated workpapers are still being developed and refined in preparation for our EUP filing. The underlying assumptions and inputs to the BCR calculations that will be included in the EUP remain subject to further refinement and Commission review, and providing illustrative or interim example calculations could result in confusion or misinterpretation. Thus, PG&E does not provide a project-specific example BCR calculation at this time.

   Consistent with Commission direction and the EUP framework, the utilities will provide project-specific BCR calculations, supporting workpapers, and assumptions as part of their forthcoming EUP filings. Those filings will include the full set of cost inputs, risk model outputs, and methodological documentation necessary for stakeholder review and evaluation of BCR results for individual projects.

SCE ANSWER 001

a. SCE agrees with PG&E's response to part a.

b. SCE will calculate BCRs at the Risk Reporting Unit (RRU), consistent with its forthcoming RAMP filing.

c. SCE objects to this request as premature and unduly burdensome on the grounds that it seeks project-specific or illustrative BCR calculations prior to any submittal of an EUP. SCE is currently developing its forthcoming 2026 RAMP application and does not have example projects with BCR calculations that can be shared at this time.

SDG&E ANSWER 001

a. Yes

b. SDG&E will calculate BCRs at the circuit segment level

c. SDG&E will present BCR calculations for the two alternatives as required by the Energy Safety EUP Guidelines.

   SDG&E is currently working on its GRC filing and, at this time, does not have any available example project with BCR calculations that can be shared in c. As a result, we are unable to provide a real-project example in Excel with all supporting workpapers and assumption.

QUESTION 002

Referring to Table 1 starting on page 6:

a. Please explain the methodology for calculating "O&M savings."

b. Regarding "Total Mitigation Benefit" will it be possible to determine the risk reduction associated with each risk separately (e.g., wildfire, reliability, etc.)?

c. Regarding "Discount Rate" will all IOUs use the same discount rate in the numerator and denominator of the BCR calculation? Please explain.

   i. Will it be possible for intervenors to select a different discount rate than selected by the utility? Please explain.

d. Regarding the "ICE Calculator" please explain what "IOUs will not distinguish between customer type in the HFTD and non-HFTD" means and provide an example.

   i. Will IOUs incorporate backup power benefits into their reliability risk calculations? Please explain.

e. Regarding "Net Salvage Values" will these be included in utility PVRR calculations?

   i. Please list the utilities that will utilize PVRR in the denominator of the BCR. If they will not use PVRR, please describe the methodology used.

PG&E ANSWER 002

a. As described in the Joint IOU Application and consistent with prior discovery responses, O&M savings represent the forecasted operating and maintenance expenditures that would have been incurred under a No-Build Baseline but are avoided as a result of implementing an undergrounding project or subproject.

   Consistent with the RDF and SPD-37, O&M savings are accounted for as part of net lifetime O&M costs, which reflect the difference between forecast lifetime O&M costs of the installed mitigation and forecast lifetime O&M cost of the pre-existing infrastructure, expressed on a present-value basis. These net O&M costs are included in the denominator of the BCR together with capital implementation costs.

   This treatment aligns with RDF guidance that the BCR denominator should include incremental costs that are made necessary by the capital investment; and it can be reasonably interpreted that costs *made unnecessary* receive the same treatment. This approach also reflects prior explanations provided in data request responses that O&M savings are not treated as a standalone benefit, nor are they tracked as realized savings for individual projects. Rather, O&M savings are prospective estimates used for cost-effectiveness evaluation at the time projects are proposed.

b. Yes. As described in the Joint IOU Application and consistent with the RDF, the Total Mitigation Benefit used in the BCR calculation may include risk-reduction benefits associated with multiple enterprise risks, including wildfire risk and reliability-related risks.

   Consistent with Commission guidance, each category of mitigation benefit can be clearly identified and distinguished to facilitate transparency and avoid double-counting. For example, the Joint IOUs' methodology allows wildfire risk-reduction benefits to be distinguished from reliability and other enterprise risk-reduction benefits when estimating Total Mitigation Benefit.

   However, consistent with Resolution SPD-37 and the Joint IOU Application, the BCR is calculated using the aggregate Total Mitigation Benefit, rather than applying separate BCR thresholds to individual risk categories. This approach aligns with the RDF definition of benefit as the reduction in risk resulting from implementation of a mitigation and with SB 884 requirements to prioritize work based on wildfire risk reduction, public safety, and reliability benefits.

c. Each utility will select its own discount rate scenario for purposes of calculating BCRs, consistent with the RDF and the Joint IOU Application. The RDF requires utilities to calculate and present BCR results using three discount rate scenarios: a Weighted Average Cost of Capital (WACC) scenario, a Societal Discount Rate scenario, and a Hybrid Discount Rate scenario.

   Under this framework, utilities are not required to use a single, uniform discount rate across all IOUs, nor are they required to apply the same discount-rate formulation in all circumstances. Instead, each utility may select the discount rate scenario it will rely on for decision-making, while still presenting results under all three scenarios, as required by the RDF.

   Consistent with the RDF, the Hybrid Discount Rate reflects a combination of financial and societal discounting approaches, which may differ by utility, and therefore does not represent a single uniform rate applied identically across all cost and benefit components. This structure is inherent in the RDF methodology and does not represent a deviation from a common BCR framework.

i. PG&E objects to this request as vague and ambiguous. PG&E understands this question to be asking whether intervenors will be able to observe BCR results under all three discount-rate scenarios. Subject to and without waiving this objection, PG&E responds as follows.

The Joint Utilities will present BCR results under all three discount-rate scenarios required by the RDF: the WACC scenario, the Societal Discount Rate scenario, and the Hybrid Discount Rate scenario.

Consistent with the RDF and the Joint IOU Application, each utility selects the discount-rate scenario it relies on for its own risk-based decision-making, while still transparently presenting results under all three scenarios for Commission and stakeholder review.

Providing BCR results under all three Commission-directed discount rate scenarios allows intervenors to review, evaluate, and reference the results associated with any of the presented discount-rate scenarios. In that sense, intervenors may rely on the discount rate scenario they consider most appropriate for their analysis or comments.

d. 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 non-residential customers.[1]

Example: The ICE Calculator assigns a specific dollar-per-customer-minute-interrupted ($/CMI) value to residential customers and a different $/CMI value to non-residential customers. Those values are applied uniformly to all residential and non-residential customers, respectively, regardless of whether a customer is located within an HFTD or non-HFTD area.

i. The Joint Utilities do not explicitly model or credit backup power resources as a separate mitigation in their reliability risk calculations for purposes of the BCR.

Reliability impacts are monetized using the ICE Calculator, which estimates customer interruption costs based on survey-derived customer damage functions. The ICE Calculator's customer damage functions include the Percentage of Customers with Backup Generators as an explanatory variable. However, this input does not represent a utility-controlled or dispatchable mitigation measure.[2]

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1 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

2 ICE-Calculator2 Phase II Final Report 27Jan2026 ICE Calculator 2 Phase II Final Report (Feb. 2026), Ch. 5, at pp. 57-58.

Consistent with the RDF and SPD-37, reliability benefits reflected in the BCR are based on modeled changes in outage frequency and duration resulting from utility-implemented mitigations. Backup power resources (e.g., customer-owned generators or batteries) are generally not utility assets, are not uniformly available, and are not controlled or dispatched by utilities, and therefore are not treated as a reliability mitigation whose benefits can be separately credited or relied upon in BCR calculations.

e. The Joint IOUs do not propose to include net salvage values as a standalone element of the BCR calculation. Consistent with the RDF and SPD-37, net salvage values are addressed through existing cost-recovery and accounting practices, rather than as a separate BCR input.

   To the extent net salvage values are reflected in a utility's analyses, they may be incorporated indirectly through depreciation rates or Present Value of Revenue Requirements (PVRR) calculations, consistent with each utility's Commission-approved accounting methods. For example, some utilities address salvage values through group accounting, which embeds expected salvage and service-life assumptions into depreciation rates rather than calculating salvage on a project-specific basis.

   Resolution SPD-37 and the RDF do not require utilities to include net salvage values in the BCR calculation or to provide PVRR calculations for purposes of evaluating cost-effectiveness under SB 884. Accordingly, utilities may treat net salvage values differently based on their existing accounting practices, without affecting the standardized BCR methodology proposed in the Joint Application.

   i. The Joint IOUs do not propose to require a uniform use of PVRR in the denominator of the BCR. Consistent with the RDF and SPD-37, utilities may apply utility-specific cost methodologies that align with their Commission-approved accounting and ratemaking practices.

      PG&E incorporates net salvage values and other lifecycle cost considerations indirectly through depreciation rates and, where applicable, through PVRR-based analyses that reflect the present value of revenue requirements over an asset's life. This treatment is consistent with PG&E's use of group accounting, under which salvage values and service-life assumptions are embedded in depreciation rates rather than calculated on a project-specific basis. PG&E does not include net salvage values as a standalone input to the BCR denominator.

SCE ANSWER 002

a. SCE agrees with PG&E's response to part a.

b. SCE agrees with PG&E's response to part b.

c. SCE agrees with PG&E's response to part c.

d. SCE agrees with PG&E's response to part d. and d.i

e. SCE does not propose to include net salvage values as a standalone element of the BCR calculation or to provide PVRR calculations for purposes of evaluating cost-effectiveness under SB 884.

SDG&E ANSWER 002

a. SDG&E agrees with PG&E's response to part a.

b. SDG&E agrees with PG&E's response to part b.

c. SDG&E agrees with PG&E's response to part c.

d. SDG&E agrees with PG&E's response to part d. and d.i

e. SDG&E does not propose to include net salvage values as a standalone element of the BCR calculation. Consistent with the RDF and SPD-37, net salvage values are addressed through existing cost-recovery and accounting practices, rather than as a separate BCR input, and therefore net salvage values do not require separate treatment as an incremental BCR input. This approach maintains alignment with existing GRC ratemaking conventions, where salvage effects are embedded within capital-related revenue requirement forecasts rather than evaluated at the project level.

    i. Additionally, SDG&E does not intend to present feeder segment BCRs using PVRR in the denominator. Incorporating PVRR at the segment level would introduce inconsistencies with both the RDF and SPD 37, which evaluate project economics based on direct project costs rather than full revenue requirement modeling. PVRR is appropriately used in GRC filings to assess future cost recovery in the context of overall revenue requirement impacts, but it is not designed to serve as the denominator in a cost effectiveness test for individual feeder segments.

QUESTION 003

Will utilities provide the rate and bill impacts of proposed EUPs? Please explain.

PG&E ANSWER 003

Rate and bill impacts associated with proposed EUPs can be developed and provided when utilities file for cost recovery, consistent with Resolution SPD-37 and established Commission ratemaking processes.

Under the SB 884 framework, utilities are not required to provide rate and bill impact analyses as part of the EUP submitted to Energy Safety. Instead, SPD-37 establishes that EUP-related cost recovery is reviewed by the Commission through a Phase 2 Application, which is the procedural vehicle by which utilities seek authorization to recover EUP costs recorded to balancing and memorandum accounts.

Rate and bill impacts are not determined by the EUP in isolation but depend on a number of factors that are evaluated in the cost-recovery proceeding, including timing of expenditures, interaction with other capital programs, authorized revenue requirements, and rate design considerations. Accordingly, rate and bill impacts are appropriately developed at the time of the Phase 2 cost-recovery filing, when the Commission evaluates whether EUP costs are just and reasonable for recovery in rates.

SCE ANSWER 003

SCE objects to this question as premature. SPD-37 establishes that EUP-related cost recovery is reviewed by the Commission through a Phase 2 application. If SCE chooses to submit an expedited undergrounding plan, the question of rate and bill impacts may be addressed at the appropriate procedural stage as part of a Phase 2 application.

SDG&E ANSWER 003

SDG&E will fully comply with and follow all Commission rules and guidelines related to reporting, transparency, and documentation of EUP cost forecasts. However, SDG&E will not provide rate or bill impacts for its proposed EUP submitted to Energy Safety.

QUESTION 004

Will the cost estimate of the BCR calculation be calculated on a present value revenue requirement basis? Please explain the methodology for each IOU.

PG&E ANSWER 004

Yes. PG&E calculates the cost estimate in its BCR calculation on a present value revenue requirement (PVRR) basis.

For PG&E, initial capital costs used in the BCR denominator are converted to a present value of revenue requirement to reflect the full lifecycle cost of an investment to customers, including authorized returns, depreciation, taxes, and other cost-of-service elements. PG&E applies a PVRR multiplier to capital installation costs and discounts those costs using its Commission-approved after-tax weighted average cost of capital (WACC). This approach aligns with PG&E's cost-of-service ratemaking framework.

In addition to capital costs, PG&E includes the present value of net ongoing O&M costs over the asset life when calculating total project costs for the BCR denominator.

SCE ANSWER 004

SCE will not provide PVRR calculations to assess cost-effectiveness for this EUP.

SDG&E ANSWER 004

No, the cost estimate used in the BCR calculation will not be calculated on a PVRR basis. Consistent with the RDF and the Commission's guidance in SPD 37, SDG&E's BCR methodology relies on direct project costs rather than the full revenue requirement stream associated with those investments.

QUESTION 005

Regarding Table 2 on page 13, do the IOUs object to reporting results for residential versus non-residential reliability benefits separately? Please explain.

PG&E ANSWER 005

PG&E does not object but does not find this requirement necessary or appropriate to report residential and non-residential reliability benefits as separate results for purposes of the BCR.

PG&E's reliability benefits are monetized using the ICE Calculator by first deriving customer-class-specific values of service (residential and non-residential), which are then applied to the customer mix at a given location to produce a single, blended reliability value. That blended value is the basis for modeling reliability risk and benefits and for calculating BCRs, consistent with the RDF, the Energy Safety EUP Guidelines, and the Joint Application.

While the underlying ICE methodology differentiates values by customer class at an input level, PG&E does not calculate, or report separate residential and non-residential reliability benefit totals as standalone outputs. Reporting reliability benefits separately by customer class would not change the BCR calculation and could be misleading, as reliability impacts are experienced jointly at a location and are evaluated on an aggregated basis.

PG&E is, however, open to providing supplemental contextual information, such as the number of residential and non-residential customers used to derive the blended reliability value, to support transparency and allow parties to understand how reliability benefits are constructed, where appropriate.

SCE ANSWER 005

SCE agrees with PG&E's response to this question.

SDG&E ANSWER 005

SDG&E agrees with PG&E's response to this question.

QUESTION 006

Page 15 states "a utility will select projects at the circuit segment level." Will utilities include information regarding whether these circuit segments have already been hardened or have installed mitigations (e.g., covered conductor?).

a. If a utility has previously hardened the circuit segment proposed for undergrounding, is this included in the estimated total risk of the circuit segment and risk reduction of undergrounding? Please explain.

b. Will unit costs for the BCR calculations be calculated based on project-specific unit costs (engineering estimates), general average values, or something else? Please explain and provide an example.

PG&E ANSWER 006

Yes. Utilities will account for existing and planned mitigation work on circuit segments as part of the project evaluation and selection process.

For PG&E, as circuit segments advance through the Project Acceptance Framework, information regarding prior system hardening, undergrounding, or other installed or planned mitigations (including covered conductor and hybrid solutions) is incorporated into the evaluation of circuit segments. In particular, after the Screen 3 evaluation, PG&E will identify portions of circuit segments that have been previously hardened or undergrounded, or that are already planned to be hardened or undergrounded, consistent with the EUP Guidelines and PG&E's reporting requirements.

This information is used to ensure that:

- Risk and benefit calculations reflect current system conditions, and
- Circuit segments are evaluated net of prior or planned mitigation, rather than being treated as greenfield.

Information regarding existing and planned mitigation work is reflected in the circuit segment-level information reported through the EUP and associated progress reports, consistent with the EUP Guidelines' requirements for tracking physical changes to circuit segments.

a. Risk and risk-reduction estimates reflect the incremental benefit of undergrounding relative to the current condition of the circuit segment, including any prior or planned mitigation.

   PG&E's wildfire risk modeling attributes risk to overhead distribution facilities. When portions of a circuit segment have been previously undergrounded and incorporated into the applicable version of PG&E's Wildfire Distribution Risk Model (WDRM), the associated risk is removed from the estimated total risk and is therefore not included in the risk-reduction attributed to a proposed undergrounding project. Where undergrounding has occurred but has not yet been incorporated into the current WDRM version, PG&E accounts for those changes through baseline updates to ensure that only the incremental risk reduction from remaining overhead facilities is attributed to undergrounding.

   This approach is consistent with the Energy Safety EUP Guidelines, which require utilities to evaluate risk and risk reduction net of prior mitigation.

b. Unit costs used in the BCR calculations will be based on the best available cost information at the time of analysis, with the level of specificity refining as projects advance through development.

   For projects with project-specific cost information available (e.g., scoped projects with engineering estimates), the utilities will use those project-specific unit costs in the BCR calculation. Where project-specific information is not yet available, utilities will use engineering estimates or representative average unit costs derived from recent experience, forecasts, or adopted cost data, consistent with prior regulatory filings.

As projects progress and more detailed cost information becomes available, unit costs are updated to reflect the most current information, ensuring that BCR results remain grounded in realistic and auditable cost assumptions.

Example: At an early screening stage, a utility may use an average undergrounding cost per mile derived from recent undergrounding projects or adopted forecasts to evaluate relative cost-effectiveness. Once a circuit segment is fully scoped and engineered, the utility would replace that average with the project-specific unit cost for that circuit segment in subsequent BCR calculations.

SCE ANSWER 006

a. SCE agrees with PG&E's response to this question.

b. SCE will provide similar information using its own risk models at the appropriate Risk Reporting Unit (RRU) level.

SDG&E ANSWER 006

SDG&E agrees with PG&E's response to this question.

QUESTION 007

Page 22 states,

> "The IOUs recommend reporting unit costs as the present value of a specific base year. The base year should be defined as the year a utility's EUP becomes effective which would be consistent with BCR Year Zero."

a. What discount rate will be used to calculate present value?

b. Why is it appropriate to calculate unit cost on a present value basis? Please explain.

c. Please provide an example calculation of this where an EUP is approved for 2028 and a project cost occurs in 2033.

PG&E ANSWER 007

a. Consistent with the RDF, the utilities will calculate and present present-value results using the three Commission-approved discount rate scenarios: the Weighted Average Cost of Capital (WACC) scenario, the Societal Discount Rate scenario, and the Hybrid Discount Rate scenario.

b. Calculating unit costs on a present value basis is appropriate because the costs and benefits of undergrounding and alternative mitigations occur over multiple years, and present-value treatment allows those future costs and benefits to be measured on a consistent, comparable basis.

   Consistent with the RDF and prior Joint IOU filings, present-value calculations ensure that:

   - Costs incurred in different years are appropriately time-weighted,
   - Mitigation alternatives with different capital and operating costs profiles can be compared on an “apples-to-apples" basis, and
   - Benefit-Cost-Ratios reflect the full lifecycle cost of an investment rather than nominal or year-specific expenditures.

   Anchoring present-value unit costs to BCR Year Zero further ensures consistency across projects within a utility’s EUP portfolio and alignment with Commission-approved cost-benefit evaluation practices.

c. Example: Assume a utility’s EUP becomes effective in 2028, which serves as BCR Year Zero, and a portion of a project’s capital cost is incurred in 2033.

   To calculate the present value of that 2033 project cost for purposes of the BCR, the utility would discount the 2033 cost back to 2028 using the applicable discount-rate scenario, consistent with the RDF. For example, if a project incurs $10 million of capital cost in 2033, that cost would be discounted over five years (from 2033 back to 2028) to calculate its present value in 2028 dollars. That discounted value would then be included in the BCR denominator as part of the total present-value project cost.

   Consistent with the RDF, the monetized risk reduction benefits included in the BCR numerator are treated in a parallel manner. Specifically, the utility estimates the annual stream of incremental risk reduction attributable to the project relative to the baseline, monetizes those risk reductions in dollars, and discounts each year’s monetized risk reduction back to BCR Year Zero using the same applicable discount-rate scenario. The present value of those discounted annual risk reductions, summed over the expected life of the asset, constitutes the total mitigation benefit included in the BCR numerator.

   This approach ensures that all costs and monetized risk reduction benefits are expressed in consistent BCR Year Zero terms, allowing costs and benefits incurred in different years to be evaluated on a comparable present-value basis and aligned with Commission-approved cost-benefit evaluation practices.

SCE ANSWER 007

a. SCE agrees with PG&E’s response to this question.

b. SCE agrees with PG&E’s response to this question.

c. SCE agrees with PG&E’s response to this question.

SDG&E ANSWER 007

a. SDG&E agrees with PG&E's response to this question.

b. SDG&E agrees with PG&E's response to this question.

c. SDG&E agrees with PG&E's response to this question.

QUESTION 008

At pages 24-25, the utilities state,

> "While the utility cannot confirm the actual number or cost of avoided inspections and maintenance activities that did not occur, it can instead provide an estimated value of those avoided activities and costs."

Will these estimated savings be incorporated in utility GRC applications to reduce forecast revenue requirements? Please explain.

PG&E ANSWER 008

PG&E objects to this question to the extent it seeks to prejudge how estimated avoided inspection and maintenance costs associated with a proposed EUP would be reflected in future GRC applications.

Subject to and without waiving these objections, PG&E responds as follows: Under SB 884 and Resolution SPD-37, such estimates are used solely to evaluate the relative cost-effectiveness of mitigation alternatives in BCR calculations and do not constitute determinations of revenue-requirement adjustments.

Any determination regarding how realized cost savings are reflected in revenue requirements is appropriately addressed in future GRC proceedings, not through the EUP BCR methodology.

SCE ANSWER 008

SCE objects to this question to the extent it seeks to prejudge how estimated avoided inspection and maintenance costs associated with a potential EUP would be reflected in future GRC applications.

SCE also objects to this question as premature and outside the scope of this proceeding. Any determination regarding how certain savings may be reflected in individual utility GRC revenue requirements is appropriately addressed in future individual GRC proceedings, not through the Phase I Joint Application.

SDG&E ANSWER 008

SDG&E agrees with PG&E and SCE's response to this question.

QUESTION 009

Page 27 states,

> "The audit will confirm that the costs for undergrounding projects and/or subprojects for which recovery is sought in the EUP are not also included in a utility's General Rate Case (GRC) or other proceeding."

Please explain the process by which this will be accomplished and provide an example.

PG&E ANSWER 009

PG&E objects to this question to the extent it seeks detailed implementation procedures that depend on future Commission approvals, including approval of the EUP, establishment of associated balancing and memorandum accounts, and adoption of the proposed audit framework.

Subject to and without waiving these objections, PG&E responds as follows: Consistent with the Joint IOUs Phase 1 Application, PG&E proposes that the audit will verify that costs recorded for EUP undergrounding projects and subprojects are segregated and tracked separately from costs recovered through the GRC or other proceedings. This is accomplished through distinct cost accounting and project-tracking mechanisms, including the use of dedicated work orders, management activity type (MAT) codes, and balancing account entries associated with EUP work.

Under this approach, costs incurred for EUP undergrounding projects are recorded to EUP-specific accounts, while costs for non-EUP system hardening or other distribution activities continue to be recorded and recovered through the GRC or other authorized mechanisms. As part of this audit, the auditor would confirm that costs recorded for recovery through the EUP are not also reflected in GRC revenue requirements or other cost-recovery proceedings.

Example: If PG&E undertakes undergrounding work on a circuit segment as part of the approved EUP, the capital costs for that work would be recorded under EUP-designated work orders and MAT codes and recovered through the EUP cost-recovery mechanism. The audit would verify that those same costs are excluded from GRC plant balances, revenue-requirement forecasts, and other recovery requests, ensuring no double recovery occurs.

Additional details regarding account structures, audit procedures, and documentation requirements will be addressed in the EUP Phase 2 application and associated audit implementation, consistent with Commission direction.

SCE ANSWER 009

SCE objects to this question to the extent it seeks detailed implementation procedures that depend on future Commission approvals, including approval of the EUP, establishment of associated balancing and memorandum accounts, and adoption of the proposed audit framework. SCE also objects to this question as premature because additional details regarding account structures and audit procedures will be addressed in the Phase 2 application process, if a utility submits such an application. Subject to these objections, SCE responds as follows:

Consistent with the Joint IOUs' Phase 1 Application, SCE proposes that the audit would verify that costs recorded for EUP undergrounding projects and subprojects, if any are submitted as part of an EUP, are segregated and tracked separately from costs recovered through the GRC or other proceedings.

SDG&E ANSWER 009

SDG&E agrees with PG&E's response to this question.

QUESTION 010

Page 32 states,

> "the actual costs of an undergrounding project vary from the estimated forecast cost because of the timing and information needed to fully develop a sound project cost estimate."

a. Please provide the expected cost variance from estimate to actual of projects and sub-projects (eg +/- 25%).

b. Why is it not possible to "develop a sound project cost estimate" for the Phase 2 EUP Application?

c. Regarding "forecast cost(s)" for undergrounding project BCR calculations, will utilities estimate the costs of high-risk alternative projects not selected for undergrounding? Or will forecast cost estimates only be provided for the projects selected by the utility? Please explain.

PG&E ANSWER 010

a. Estimated project costs used in the EUP are developed at the Screen 3 stage, after a project has been scoped but before final engineering, permitting, and construction sequencing are complete. As a result, some differences between estimated and actual costs are expected as additional information becomes available and project details are refined.

   Rather than applying a single, fixed percentage variance across all projects or sub-projects, PG&E recognizes that expected variance depends on the level of project definition, site-specific conditions, and external factors such as permitting requirements, material availability, and construction timing. Cost estimates are therefore progressively refined as projects advance through design and execution.

Consistent with Resolution SPD-37, the purpose of Screen 3 cost estimates are to support comparative evaluation and prioritization of projects, not to establish final construction costs. Differences between forecast and recorded costs are addressed through the portfolio-level cost-recovery and audit framework, which is designed to accommodate reasonable variation between estimated and actual costs across a portfolio of projects.

b. At the time of the Phase 2 EUP Application, confirmed undergrounding projects have generally progressed through Screen 3, meaning they have been scoped at a planning level but have not yet completed final engineering, permitting, detailed constructability reviews, or contractor procurement. As a result, key cost drivers that materially affect final project cost are not yet fully known or confirmed.

   In particular, final project costs depend on factors that are resolved later in the project lifecycle, including:

   - Detailed route refinement and final design
   - Permitting conditions and agency requirements
   - Constructability constraints and site conditions
   - Material availability and market pricing, and
   - Construction sequencing and execution approach

   Consistent with the Joint IOU Application, the purpose of Phase 2 cost estimates are to support portfolio-level cost recovery review and auditability, not to establish final construction budgets for individual projects. The EUP and SPD-37 frameworks expressly recognize that undergrounding project costs will vary between forecast and actual because estimates are developed before sufficient information is available to produce a fully mature project-level cost estimate.

   While Phase 2 cost estimates are reasonable for evaluating compliance with portfolio-level cost-recovery conditions, a "sound" final project cost estimate can only be developed after projects advance into final design and construction, when the necessary information becomes available.

c. Forecast cost estimates are provided for the undergrounding projects selected by the utility and included in the EUP, consistent with the EUP Guidelines and SPD-37 data-table requirements.

   As part of the project evaluation and selection process, utilities compare undergrounding to alternative mitigations using modeled cost and benefit inputs to assess relative cost-effectiveness. However, the EUP and SPD-37 reporting requirements do not require utilities to develop or report standalone forecast cost estimates for alternative projects that are not selected for undergrounding.

SCE ANSWER 010

SCE agrees with PG&E's response to this question.

SDG&E ANSWER 010

SDG&E agrees with PG&E's response to this question.

QUESTION 011

Page 36 states,

> "The joint IOUs 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 conductor plus fast trip settings (this is referred to as an "estimate uncertainty factor")."

a. How was the 70 percent determined? Please explain.

b. Please provide a numerical example showing how the 70 percent will be applied or calculated.

PG&E ANSWER 011

a. The 70 percent assessment reflects an estimate uncertainty range applied to BCR results to account for known limitations and uncertainty in cost estimates and risk-model outputs at the project-selection stage.

   Specifically, PG&E plans to apply a 30 percent estimate uncertainty range in the EUP application, which means that a more risk reducing mitigation alternative may be considered when its estimated BCR is at least 70 percent of the BCR for Overhead Hardening + EPSS. The 70 percent framing is simply 100 minus the 30 percent uncertainty range and does not represent a separate or additional threshold.

   This estimate uncertainty range is grounded in:

   - Industry-standard estimating practice, which recognizes that cost estimates developed during project scoping are not yet fully mature;
   - Energy Safety's recommendation in PG&E's 2026-2028 Base WMP to reduce the prior 50 percent estimate uncertainty range to 30 percent, reflecting improvements in data quality and modeling while still acknowledging residual uncertainty; and
   - Inherent uncertainty in modeled risk point estimates, driven by compounding assumptions, variability in inputs, and structural limitations of quantitative risk models.

   Where BCR results fall within this uncertainty range, PG&E evaluates site-specific factors that are not fully captured in quantitative models, such as ingress and egress constraints, tree-strike exposure, and PSPS considerations, to determine whether a more risk-reducing alternative is a more prudent mitigation than overhead hardening. The estimate uncertainty range therefore provides appropriate flexibility to select the safer, more risk-reducing option when modeled BCRs are close and known uncertainty exists.

b. Below is a numerical example of how the 70 percent factor will be applied:

In this example:
$Alt_{\_0}$ = Undergrounding

$Alt_{\_1}$ = Overhead Hardening + EPSS

$Alt_{\_2}$ = Hybrid Mitigation (Note: this mitigation alternative may vary by utility)

Consider Alternative Mitigation if: $(70\%) * BCR_{Alt\_1} \leq BCR_{Alt\_x}$

Using the example data in the table below

Category	$Alt_{\_0}$ (UG)	$Alt_{\_1}$ (OH+EPSS)	$Alt_{\_2}$ (Hybrid)
Benefits	$25	$15	$21
Costs	$4	$2	$3
BCR	6.25	7.5	7.0

Consider highest BCR alternative mitigation that fulfills: $(70\%) * BCR_{Alt\_1} \leq BCR_{Alt\_x}$

$(70\%) * BCR_{Alt\_1}$ is calculated as shown below:

$(70\%) * 7.50 = 5.25$

BCRs for both $Alt_{\_0}$, *6.25*, and $Alt_{\_2}$, *7.0* are greater than 5.25, so a more risk reducing alternative than overhead hardening would be selected in this case contingent on local conditions.

The BCR for $Alt_{\_2}$ is greater than the BCR for $Alt_{\_0}$, therefore, **$Alt_{\_2}$ (Hybrid)** would be selected in this case contingent on local conditions.

SCE ANSWER 011

SCE agrees with PG&E’s response to this question.

SDG&E ANSWER 011

SDG&E agrees with PG&E’s response to this question.

QUESTION 012

Page 37 states,

> "While the BCR is a valuable metric, it is not comprehensive and does not incorporate this type of site-specific risk information. It would be unwise to disregard location-specific considerations and the judgment of subject-matter experts."

Please explain why the listed factors (Ingress/Egress, Tree Strike, and PSPS risk) cannot be incorporated into utility risk models based on more granular/location-specific information.

PG&E ANSWER 012

While utilities' wildfire and reliability risk models are industry-leading and continuously improving, they are designed to operate at a system-wide and programmatic scale using standardized datasets. Certain site-specific risk factors, such as ingress/egress constraints, tree-strike potential, and PSPS impacts, cannot be fully or reliably represented within those models because they depend on localized, dynamic, and qualitative conditions that are not consistently available in structured, model-ready form

- Ingress/Egress risk is inherently location-specific and situational, often requiring street-level assessment of evacuation routes, access constraints, terrain, and community layout. These conditions are not captured in the geospatial and asset datasets that underpin wildfire risk models and therefore require site-specific evaluation during project scoping, informed by subject-matter-expert review.
- Tree-strike risk depends on changing environmental conditions, including tree health, species, growth patterns, and recent weather impacts. While risk models may incorporate high-level vegetation and exposure indicators, they do not reflect real-time or site-specific tree conditions, which are best assessed through field reviews and engineering judgment.
- PSPS risk is influenced by operational, meteorological, and circuit-specific factors that vary by location and event. While models can estimate aggregate outage risk, they are not designed to capture how undergrounding may affect localized PSPS frequency or duration in specific communities, particularly where PSPS exposure is driven by operational or topological considerations.

Because these factors are not uniformly quantifiable, not static over time, and not available at consistent resolution across the system, incorporating them directly into quantitative risk models could introduce false precision or inconsistent results. Instead, consistent with prior filings, utilities incorporate these considerations through structured, site-specific assessments conducted during project scoping, using engineering studies and subject-matter-expert judgment to supplement model-based BCR results.

While the BCR provides a critical quantitative foundation for mitigation selection, it is appropriate, and consistent with the Joint IOU Application, RDF, and prior data-request responses, to consider ingress/egress, tree-strike, and PSPS risk outside the risk models when BCR results are close and additional location-specific information is needed to determine the most prudent mitigation.

SCE ANSWER 012

Based on Commission guidance in its 2025 General Rate Case (GRC) Decision, SCE has taken appropriate measures to account for Ingress/Egress and PSPS risk in its monetized benefits calculations. Additionally, SCE also accounts for Hazard Trees (i.e., Tree Strike) in its probability of ignition model. However, as the Joint IOU application states, these models are not comprehensive and may not incorporate site-specific risk information at certain levels of granularity. For this reason, SCE does not rely solely on modeled outputs in its decision-making process.

SDG&E ANSWER 012

SDG&E's wildfire and reliability risk models are designed to evaluate wildfire, PSPS, and PEDS risks and benefits at the asset-span level using standardized and consistently available data. These models provide an important quantitative foundation for mitigation planning; however, they rely on historical data such as outages, ignition records, weather, and fuels conditions, along with modeling assumptions that may not fully capture highly localized or site-specific risks.

Certain factors, such as ingress and egress constraints, tree strike risk, and PSPS exposure, are inherently location-specific, dynamic, and not uniformly available in model-ready datasets. Given these known model limitations, SDG&E evaluates these factors through additional, site-specific assessments conducted during detailed project scoping and informed by subject-matter expert review.

These qualitative considerations are used to supplement Benefit-Cost Ratio results, particularly in instances where the BCRs for undergrounding and alternative mitigation measures are very similar and additional location-specific information is necessary to determine the most prudent mitigation option.

QUESTION 013

Page 40 states,

> "Certain feeder segments feed critical facilities like public safety facilities, hospitals, and schools."

Do the IOUs assess whether these facilities have backup power when estimating reliability risk? Please explain.

PG&E ANSWER 013

No. The Joint IOUs do not assess facility-specific backup power availability (e.g., whether a particular hospital, school, or public safety facility has on-site backup generation or batteries) when estimating reliability risk for purposes of the BCR calculations.

Reliability risk is monetized using the ICE Calculator, which relies on survey-based customer damage functions and system-level inputs, rather than facility-specific data. These functions and inputs may implicitly reflect average customer behavior, including the prevalence of backup power across customer classes, but they do not represent facility-specific conditions or the operational capability, duration, or effectiveness of backup power at individual locations.

Backup power resources vary widely by facility type, configuration, maintenance practices, and fuel availability. In addition, because these resources are generally not utility-owned, controlled, or dispatchable, they cannot be relied upon as a consistent or verifiable mitigation of reliability risk at the circuit-segment level. Incorporating site-specific backup power assumptions would introduce inconsistency and false precision into reliability risk estimates.

Hence, when feeder segments serve critical facilities, reliability risk estimates reflect standardized, system-wide ICE inputs rather than individualized assessments of backup power at specific facilities.

SCE ANSWER 013

SCE agrees with PG&E's response to this question.

SDG&E ANSWER 013

SDG&E agrees with PG&E's response to this question.