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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Refine the Risk-Based Decision-Making Framework for Electric and Gas Utilities.	Rulemaking 26-04-016

THE PUBLIC ADVOCATES OFFICE OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO REFINE THE RISK-BASED DECISION-MAKING FRAMEWORK FOR ELECTRIC AND GAS UTILITIES

ANNA YANG
MILES GORDON
MERLIN HANAUER
Senior Regulatory Analysts

LARA VANDERBILT
MEGAN THAI
Utilities Engineers

CHRISTOPHER PARKES
Supervisor

Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-2144
Email: Anna.Yang@cpuc.ca.gov

MICHAEL EINHORN
Attorney

Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-4852
Email: Michael.Einhorn@cpuc.ca.gov

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these opening comments on the *Order Instituting Rulemaking to Refine the Risk-Based Decision-Making Framework for Electric and Gas Utilities* Rulemaking (R.) 26-04-016 (Rulemaking) adopted on April 30, 2026.[1] The Rulemaking requests comments on the scope of the proceeding and procedural questions as well as the substantive questions in Appendix A of the Rulemaking that relate to Risk Tolerance, Benefit-Cost Ratio (BCR) modifications, Risk Assessment and Mitigation Phase (RAMP) schedule/process, and small and multi-jurisdictional utilities (SMJU) reporting. Cal Advocates addresses these issues in Sections II. A and B below.[2]

II. COMMENTS

A. Responses to the scoping and procedural questions.

Cal Advocates recommends three general modifications to the scoping and procedural rulemaking. First, the Commission should structure this rulemaking into multiple phases. The scoping topics for each Phase are discussed in subsections below. A phased approach would give parties adequate opportunity to meaningfully engage on

[1] R.26-04-016, *Order Instituting Rulemaking to Refine the Risk Based Decision Making Framework for Electric and Gas Utilities*, April 30, 2026.

[2] Rulemaking at 18-19.

each topic before moving forward. This structure reduces the risk that matters are left unresolved or insufficiently examined. For Phase I topics, the Commission should designate Risk Tolerance, BCR Modifications, RAMP schedule and process, and SMJU reporting.

Second, the Commission should explicitly specify that the proposed scope of topics in Phase 1 shall also include the development of a unified framework for incorporating risk scaling and risk aversion, as discussed in Section A.1.a.

Third, the Commission should clarify and expand the scope of topics in this rulemaking to include the specific topics discussed below for discussion in separate phases.

1. Cal Advocates' proposed issue topics:

In this subsection, Cal Advocates responds to the Rulemaking request for comments on the issue of "[w]hether changes to the preliminary scope of issues should be made?"[3]

a) Proposed Phase I topics:

(1) The Commission should develop and adopt a standard for quantifying risk and risk mitigation ratepayer costs.

The Commission has yet to adopt a specific standard for how to calculate risk or cost, including level of granularity, risk scaling, or risk aversion. As a result, utilities often calculate risk reduction using diverse, inconsistent, and arbitrary methods of assessing risk aversion, risk scaling, risk granularity, and location granularity.[4] Relatedly, utilities calculate costs using diverse and arbitrary methods for assessing mitigation costs. Importantly, utilities may include only installation costs or include only

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[3] Rulemaking at 18.

[4] *See* A.25-05-013/13, *Safety Policy Division Evaluation Report on Sempra's 2025 RAMP Applications (A.)25-05-10* (SPD Report on Sempra's 2025 RAMP), October 10, 2025, at 131 ("SDG&E's risk scaling process does not exhibit a meaningful correlation with either unscaled risk value or unscaled CoRE values of segments. This finding suggests that scaling factors have been applied inconsistently, potentially undermining the integrity of risk prioritization and SDG&E's CBR calculation.").

a subset of total costs recovered from ratepayers. For example, a utility might exclude all associated lifecycle capital and expense mitigation costs recovered from ratepayers, including:[5]

- Future requisite asset retirement and disposal costs
- Maintenance and Operations costs
- Utility return on equity earnings
- Income taxes and property taxes
- Engineering costs
- Other costs

Any future potential assessment of risk tolerance or ratepayer tolerance necessarily requires utilities and the Commission to accurately assess these risks and costs.[6] Without a standard, it is in utilities interest to select methodologies optimized for shareholder value,[7] and the Commission's evaluation will be heavily burdened by myriad approaches.

Furthermore, without a standard for specifying granularity of and locational risk assessment, utilities and the Commission will be unable to ensure that risk mitigations are prioritized and targeted to the locationally specific highest risk areas. A risk reduction methodology that uses average risk reduction valuations regardless of the risk or risk reduction mitigation at a specific location will mask the opportunity to optimize ratepayer funds to prioritize and expedite mitigation of the greatest risks.

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[5] Rulemaking at 13. ("In D.25-08-032, the Commission recognized that a PVRR will make BCR calculations more accurate and representative of the **lifetime costs** of a risk reporting unit and suggests a successor proceeding discuss whether a PVRR metric should be required in BCR calculations.") (Bold emphasis added)

[6] See, e.g., Rulemaking at 11 (asking parties to "[p]ropose an approach to quantifying risk tolerance . . ." to "allow the Commission, in a utility GRC Phase 1 proceeding, to better assess trade-offs between risk mitigation and affordability as well as the progress the utilities are making towards mitigating risk."); SPD Report on Sempra's 2025 RAMP at 131 (if utility applies risk scaling factor inconsistently, it potentially undermines the integrity of risk prioritization).

[7] SPD Report on Sempra's 2025 RAMP at 131, 132. ("…SPD's concern that SDG&E's risk scaling is not meaningfully linked to mitigation planning. Instead, the evidence suggests that SDG&E's risk scaling primarily serves to increase CBR values, rather than to guide risk-informed prioritization.")

Cal Advocates recommends that the Commission develop and adopt a standard for risk and mitigation cost valuation. The Commission's standard should include granular locational assessment of risks, risk scaling and risk aversion (if permitted), and a full disclosure of all mitigation costs recovered from ratepayers, disclosing complete present value revenue requirement (PVRR).

(2) The Commission should fix risk assessment granularity and averaging.

Currently, the RDF defines the Risk Reporting Unit (RRU) as: "*A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates the risk associated with a group of contiguous assets or systems that exhibit high levels of risk.*"[8] The Commission states that the RRU must be:

(a) traceable through most, if not all, stages of a lifecycle, including but not limited to, scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.

(b) forecastable to at least the third post-test year of a GRC cycle.

(c) auditable in terms of timing, location, work units, cost, and risk reduction.

(d) able to aggregate up to the Mitigation Program or Control Program.[9]

Consistent with the above, the risk reduction achieved by a specific RRU must be "auditable" and the Commission and parties should receive the most accurate information possible regarding the risk reduction achieved by utilities. The Commission should, therefore, update the definition of the RRU to specify that the risk reduction achieved by the RRU must be measured at the specific location at which the risk reduction takes place.

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[8] D.25-08-032 at 64-65.

[9] D.25-08-032, Appendix A, A-16.

Current utility practices for reporting risk reduction do not achieve the above objectives. For example, when mitigating wildfire risk on electrical distribution circuits, PG&E's current practice is to use proportional, or *pro rata*, methods[10] of calculating risk.[11] PG&E's methods are inappropriate to measure risk at a specific location. They exhibit two fundamental and related problems. First, proportional methods cannot capture heterogeneity in risk within a circuit segment because they are a function of the average risk in a circuit segment. Second, and more fundamentally, proportional methods target the wrong quantity. The relevant quantity for evaluating subproject-level risk reduction is the actual pre-mitigation risk associated with the specific assets and locations subject to mitigation. By construction, however, proportional methods estimate only the proportional risk implied by the circuit-segment-level average.

Proportional methods will generally be biased when risk varies within a circuit segment. In fact, a proportional estimator will only be accurate under two limiting conditions: (1) when there is no variation in risk within a circuit segment, or (2) when the mitigated portion of the circuit segment happens to exhibit the same risk as the mean of the circuit segment itself. Outside of these special cases, proportional methods will overstate or understate actual risk removed by the mitigation.

RRUs and their projected and actual risk reduction must accurately reflect the benefits of selected mitigations and in turn inform efficient mitigation decisions to ensure that ratepayer funds are prudently spent. To do this, location-specific measures of risk are necessary and the RDF should reflect this necessity.

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[10] For example, a proportional method measures risk a location j as a function of total risk and miles in circuit segment (CS) k: $Risk_j = TotalCSrisk_k \times MitigationMiles_j / TotalCSMiles_k$

[11] For example, PG&E calculate its risk reduction by distributing its risk evenly across the circuit segment, regardless of the actual risk at a given location along the circuit segment, and then calculates its risk reduction based upon that distribution of risk. See Advice Letter 7150-E-A, "Supplemental: PG&E's 2023 General Rate Case OP 24 System Hardening Baseline and Risk Reduction Methodology", February 20, 2024, at 6-7.

(3) The Commission should modify the Risk-Based Decision-Making Framework to require utilities to adopt a unified framework for incorporating risk aversion.

The current Risk-Based Decision-Making Framework (RDF) allows utilities to, "Apply a Risk Scaling Function to the Monetized Levels of an Attribute or Attributes (from Row 6) to obtain Risk-Adjusted Attribute Levels."[12] Currently, each utility implements a different method of incorporating risk aversion into the BCR framework, each of which constitutes a vastly different approach. As a result, BCRs would change, and thus mitigation priorities would change, if one utility were to adopt another utility's approach to risk aversion. This raises a broader concern regarding consistency and comparability across utilities that operate under the same regulatory framework. Further, because the choice of risk-aversion framework directly affects estimated residual risk and the amount of mitigation deemed economically efficient, utility-specific methodological choices will affect the inferred level of residual risk and the implied risk tolerance remaining on the system following mitigation implementation.

To the extent that risk aversion is incorporated into the RDF, its implementation should rely on a common and theoretically sound framework so that differences in estimated risk and mitigation prioritization reflect actual differences in system risk rather than utility-specific methodological choices. The RDF should be modified to require utilities to adopt a unified framework for incorporating risk aversion into the BCR framework that is founded in the expected utility framework and follows best practice in the cost-benefit analysis literature.

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[12] D.25-08-032, *Phase 4 Decision*, August 28, 2025, at Appendix A, Row 7.

b) **Phase 2 topics:**

(1) **The Commission should modify the RDF to require utilities to submit mitigation alternatives that offer the best cost-benefits.**

Decision (D.)14-12-025[13] and D.18-12-014[14] direct utilities to identify two alternative risk mitigations that the utility considered for each RAMP filing. This means that under the current RDF process, a utility may propose any two risk mitigation options but exclude less costly mitigation alternatives with significantly better cost-benefits from its RAMP proposals. To prevent this, the Commission should modify the current RDF rules to require utilities to identify, fully analyze, and compare cost-effective mitigation alternatives in the RAMP or GRC processes. Being able to compare cost-effective mitigation alternatives is vital for the Commission's and parties' efforts to efficiently evaluate ratepayer-funded risk mitigation proposals and ensure they are in the public interest.

(2) **The Commission should require utilities to include an analysis and forecast of ratepayer bill impacts when comparing alternative risk mitigation programs.**

California ratepayers are facing an affordability crisis.[15] Information surrounding the risk of unaffordable utility bills, and the safety impact associated with such, is not yet required. However, unless the Commission requires utilities to produce the rate impact analysis of unaffordable utility bills, the Commission would never know whether the

[13] D.14-12-025, *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004*, December 9, 2014, at 32 and 37-38. ("The Refined Straw Proposal recommends that the utility's RAMP report contain at least the following…For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan… We adopt the following RAMP process...The utility's RAMP submission shall contain the information that the Refined Straw Proposal has described, as summarized above.")

[14] D.18-12-014, *Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications*, December 20, 2018, at 34.

[15] D.25-08-032 at 123, Findings of Fact (FoF) #1. ("California ratepayers face growing challenges in affordability of utility rates.")

program is a just and reasonable solution, or a high-cost alternative of equal or lesser impact.

In Pacific Gas and Electric Company's (PG&E) 2024 RAMP proceeding, Cal Advocates emphasized that, PG&E did not analyze ratepayer bill impacts when evaluating or selecting risk mitigation programs.[16, 17] When PG&E was asked why they did not do so, PG&E responded that it did not conduct an analysis of these issues because there is currently no requirement, guidance, or adopted analytical method in the RDF (developed in R.20-07-013)[18] to perform such an analysis.[19, 20, 21, 22] Thus, it appears utilities, such as PG&E in this example, need to be directed to analyze affordability when choosing their risk mitigation programs. This type of analysis is essential if the Commission intends to make meaningful inroads on affordability.

c) Phase 3 topics:

(1) The Commission should modify the RDF to ensure that utilities adequately assess electric transmission-caused wildfire risk to the public.

Electric Transmission-ignited fires have proven to have some of the greatest consequences to the public, as demonstrated by the Camp Fire, Woolsey Fire, and Kincade Fire, and potentially the Eaton Fire. These first involved transmission

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[16] A.24-05-008, *The Public Advocates Office Corrected Informal Comments on the Application of Pacific Gas and Electric Company (U39m) to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report*, October 15, 2024, at 9-10. (PG&E did not "consider ratepayer bill impacts when considering, evaluating, and selecting alternative risk mitigation programs.")

[17] Opening Comments on PG&E's 2024 RAMP at 6. Accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K970/548970174.PDF

[18] R.20-07-013, *Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities*, July 16, 2020.

[19] PG&E's Data Request Response in Data Request *RAMP-2024_DR_CalAdvocates_001-Q005Supp01,* Question 5e.

[20] PG&E's Data Request Response in Data Request *RAMP-2024_DR_CalAdvocates_002-Q003*.

[21] PG&E's Data Request Response in Data Request *RAMP-2024_DR_CalAdvocates_002-Q004.*

[22] PG&E's Email to Service List A.25-05-009: *[EXTERNAL] A.25-05-009; 2027 General Rate Case Workpapers of PG&E*, Attachment: *WP 1-01_ 2024 RAMP to 2027 GRC Feedback Final.xlsx*, August 11, 2025.

equipment and resulted in loss of life, widespread property destruction, and billions of dollars in damages.[23, 24, 25, 26, 27] While utilities have identified transmission risk in their

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[23] 2018 Camp Fire: Economic loss estimate: $17 billion; 85 lives lost. 2018 Woolsey Fire: Insured loss: $4.5 Billion; 3 lives lost. 2019 Kincade Fire: >75,000 acres; > 370 Structures; 4 injuries. 2025 Southern California Eaton Wildfire: Economic loss estimate: $25 Billion; 19 Lives Lost; investigation is ongoing.

[24] California Public Utilities Commission, Safety and Enforcement Division (SED), *SED Incident Investigation Report for 2018 Camp Fire with Attachments*, November 8, 2019, at 1-2. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/wildfire/staff-investigations/i1906015-appendix-a-sed-camp-fire-investigation-report-redacted.pdf. (CAL FIRE determined that the fire was caused by electric transmission lines owned and operated by PG&E, which burned approximately 153,336 acres, destroyed 18,804 structures, and resulted in 85 fatalities.)

[25] California Public Utilities Commission, Safety and Enforcement Division, Electric Safety and Reliability Branch. *Investigation Report of the Woolsey Fire*, at 1. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/investigations-wildfires/sed-investigation-report---woolsey-fire---redacted.pdf. (CPUC's SED investigation determined that a loose transmission down guy wire contacted an Edison 16 kV jumper wire and caused an arc flash, igniting he brush below. The Woolsey Fire went on to burn 96,949 acres of land, destroy 1,643 structures, cause three fatalities, and prompted the evacuation of more than 295,000 people in the area. The total damage to property is estimated to be approximately $6 billion.)

[26] California Public Utilities Commission, *CPUC Penalizes PG&E for 2019 Kincade Wildfire*, December 2, 2021. Accessed at: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-penalizes-pge-for-2019-kincade-wildfire. (CPUC's SED investigation found the Kincade Fire, which burned more than 77,000 acres and destroyed nearly 374 structures, involved multiple violations of General Order 95 by PG&E transmission infrastructure.)

[27] Southern California Edison Company, Supplemental Report to the California Public Utilities Commission Regarding the Eaton Fire, January 27, 2025. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/electric-safety-incidents-reported-by-ious/2025-incidents/eaton-fire-update-1-27-25.pdf. (SCE reported that the preliminary origin area identified by the Los Angeles County Fire Department is in proximity to three SCE transmission towers in Eaton Canyon, and that a fault was detected on a transmission line at or near the reported fire start time; official cause determination remains pending.)

RAMP filings,[28, 29] the associated safety risk is not meaningfully quantified,[30, 31] and the RAMP does not measure the risk that transmission failures will ignite wildfires that harm the public.

The Federal Energy Regulatory Commission (FERC) regulates transmission systems for reliability,[32] but not safety.[33] The Commission established the Transmission Project Review (TPR) Process through Resolution E-5252 to review utilities' capital transmission projects,[34] but the TPR Process does not require assessment of the public safety consequences of transmission system failures.[35] Furthermore, the RDF does not

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[28] PG&E's 2024 RAMP at PG&E-4 2-1 to PG&E-4 2-16.

[29] A.22-05-013, *Application of Southern California Edison Company (U 338-E) Regarding 2022 Risk Assessment Mitigation Phase (RAMP)*, May 13, 2022, at Appendix C: Transmission and Substation Assets.

[30] A.22-05-013, *Safety Policy Division Staff Evaluation Report on the Southern California Edison Company's 2022 Risk Assessment and Mitigation Phase (RAMP) Application (A.)22-05-013*, at 59. ("Some of the examples above have direct potential wildfire implications, even though the [Transmission and Substation Assets risk] is not classified as a RAMP-level risk. It is not readily apparent why some of the risk remediation activities SCE listed…are not included as part of the analysis in the wildfire risk chapter. By treating this as a non-RAMP risk, SCE did not provide MAVF-level risk analyses and RSE information on the risk and the associated mitigations. By placing some of these mitigations outside of the scope of a RAMP risk, SCE has effectively shielded them from Commission oversight in the RAMP process. SPD recommends that analyses of these risk mitigation activities should be incorporated into the appropriate RAMP risk chapters where appropriate.")

[31] PG&E's 2024 RAMP at PG&E-4 2-1 to PG&E-4 2-16. (PG&E identified Electric Transmission Systemwide Blackout as the transmission risk event, scoped to reliability consequences of outages, not wildfire ignition harm to the public.)

[32] Federal Energy Regulatory Commission, *What FERC Does*. Accessed at: https://www.ferc.gov/what-ferc-does.

[33] Federal Energy Regulatory Commission, *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities*, at slide 15. Accessed at: https://www.ferc.gov/sites/default/files/2020-07/ferc101.pdf.

[34] California Public Utilities Commission, *Transmission Project Review Process*. Accessed at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/transmission-project-review-process.

[35] California Public Utilities Commission, *Resolution E-5252*, April 27, 2023, at 1. Accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K896/507896441.PDF. ("There are no safety considerations with the implementation of the Transmission Project Review Process.")

require utilities to measure the risk that a transmission line failure will start a catastrophic wildfire, in any standardized way.[36]

The Commission's authority to require transmission wildfire risk assessment is not preempted by Executive Order 14308. Executive Order 14308 directs FERC to consider initiating rulemaking proceedings to establish best practices to reduce the risk of wildfire ignition from the bulk-power system.[37] The Commission's authority would be distinct, to ensure utilities assess and disclose the public safety consequences of transmission failures.

The absence of a standardized transmission wildfire risk assessment in the RAMP means the Commission cannot evaluate, on a consistent basis, whether utilities are adequately managing the risks that produce these outcomes. Therefore, the Commission should require every major electric utility to assess transmission-caused wildfire risk to the public as a standardized, mandatory part of their RAMP filings, using data they already collect, in a format that allows the Commission to compare utilities side by side.

(2) The Commission should require utilities to account for the time value of risk associated with risk mitigation implementation timelines.

Risk reduction projects, particularly those involving physical infrastructure deployment, can take multiple years to implement and can involve a lengthy process that includes feasibility assessment, engineering design, permitting, and easement acquisition

[36] *See* D.25-08-032, *Phase 4 Decision*, August 29, 2025, Appendix A, Rows 8 to 25.2.

[37] Executive Order 14308, *Empowering Commonsense Wildfire Prevention and Response*, June 12, 2025, Section 4(d) at 2. Accessed at: https://www.govinfo.gov/content/pkg/DCPD-202500685/pdf/DCPD-202500685.pdf.

before construction can begin.[38, 39, 40] Communities in high fire risk areas remain exposed to wildfire risk during the implementation period. As explained below, overhead covered conductors can shorten the period during which communities remain exposed, as illustrated by comparing PG&E's undergrounding deployment to SCE's covered conductor deployment.

PG&E has completed and energized more than 1,250 total miles[41] of underground powerlines since the announcement of its undergrounding program in 2021. 1,250 miles of undergrounding is equivalent to mitigation of only 1,000 miles of overhead powerlines.[42, 43] Southern California Edison Company (SCE) has installed approximately 7,110 circuit miles[44] of overhead covered conductor in high fire risk areas between 2018 and March 31, 2026, reflecting covered conductor's faster deployment cycle relative to

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[38] Southern California Edison, *Targeted Undergrounding Wildfire Safety*. Accessed June 4, 2026: https://www.sce.com/outages-safety/wildfire-safety/targeted-undergrounding.

[39] San Diego Gas & Electric Company's (SDG&E) undergrounding installation typically takes 24 to 36 months to implement. SDG&E's response to Data Request Number *CalAdvocates-Sempra-2025RAMP-AYN-001*, Q.2.

[40] PG&E's undergrounding and system upgrade projects are typically completed within 12-24 months. Pacific Gas and Electric Company, *System Hardening & Undergrounding*. Accessed June 4, 2026: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program/system-hardening-and-undergrounding.html.

[41] Pacific Gas and Electric Company, *System Hardening & Undergrounding*. Accessed June 4, 2026: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program/system-hardening-and-undergrounding.html.

[42] PG&E's response to Data Request *WMP-Discovery2026-2028_DR_TURN_002-Q009*, Q.9*,* April 10, 2025. ("For hybrid subprojects (partially underground and a combination of overhead hardening and/or line removal) or cases where overhead removal data is unavailable, miles are calculated using a conversion factor: 1 mile of overhead equals 1.25 miles of undergrounding.")

[43] *See* Pacific Gas and Electric Company, *Undergrounding Benchmarking Report*, April 12, 2024, at 6. Accessed at: https://www.pge.com/assets/pge/docs/outages-and-safety/safety/undergrounding-benchmarking-report.pdf. ("The conversion factor used is 1 mile overhead powerline to 1.25 miles underground powerlines, which is a conventional, industry-accepted conversion factor and also used by PG&E. ").

[44] Southern California Edison, *2026-2028 Wildfire Mitigation Plan Fact Sheet*, May 12, 2026. Accessed at: https://download.newsroom.edison.com/create_memory_file/?f_id=68279ba73d63328626179ab2&content_verified=True

undergrounding. SCE reports that, as of year-end 2024, no ignitions have occurred from the risk drivers that covered conductor is designed to mitigate at locations where it has been deployed.[45] The lack of ignitions in SCE's territory as of 2024 indicates that overhead covered conductor alternatives may reduce ignition risk. SCE's example illustrates that overhead covered conductor alternatives, which are quicker to deploy, may reduce risks during the years it takes to complete undergrounding.

The RDF does not require utilities to evaluate the time value of risk[46] when selecting among mitigation measures. Cal Advocates recommends that the Commission require utilities to account for the time value of risk associated with a risk reduction project's implementation timeline when selecting among mitigation measures, including when considering longer-lead measures such as undergrounding over faster alternatives such as overhead covered conductor or ground fault neutralizers (e.g., Rapid Earth Fault Current Limiters).

2. Preliminary categorization of this proceeding.

The Rulemaking asks "[w]hether there are objections to the preliminary categorization of this proceeding?"[47] Cal Advocates do not object to the preliminary categorization of this proceeding as quasi-legislative.

3. Need for hearings.

The Rulemaking asks "[w]hether evidentiary hearings are needed?"[48] Cal Advocates reserve the right to request evidentiary hearings to cross-examine witnesses and ensure that all relevant materials are fully presented and considered by the Commission.

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[45] *SCE's 2026-2028 Wildfire Mitigation Plan Revision 3*, January 22, 2026, at 226.

[46] The concept of "time value of risk" reflects the additional wildfire exposure communities bear while a longer-lead mitigation is being implemented. The Legislature has recognized this gap: SB 1003 (Dodd, 2023–2024) would have required utilities to account for implementation timelines when selecting mitigation measures but did not pass. *See* SB 1003, 2023–2024 Reg. Sess. (Cal. 2024).

[47] Rulemaking at 18.

[48] Rulemaking at 18.

4. Workshops on specific topics.

The Rulemaking asks "[w]hether to hold workshop(s) on any of the following topics: BCR Modifications, RAMP Schedule/Process, and/or SMJU Reporting?"[49] Cal Advocates anticipates that the issues regarding the RAMP schedule/process and SMJU Reporting may be resolved through filed comments, thus a workshop on this topic is not necessary.

However, workshop(s) on Risk Tolerance and BCR modifications would help parties better understand the proposals and issues raised regarding these topics. These topics involve technical complexity that warrant interactive discussion among parties in a way that written comments cannot fully achieve. There are open questions about what Risk Tolerance thresholds are appropriate and how they should be applied,[50] and what costs should be included in BCR calculations.[51] Holding workshops dedicated to these topics will ensure all parties have a full and meaningful opportunity to engage.[52]

5. Additional procedural issues.

The Rulemaking asks "[w]hether there are any additional procedural issues that may impact just and efficient conduct of this OIR?"[53] Cal Advocates does not have input on this question at this time.

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[49] Rulemaking at 18.

[50] D.25-08-032, *Phase 4 Decision*, August 28, 2025, at 10. ("The development of a Risk Tolerance standard will allow the Commission to answer the question of how much risk reduction is sufficient, given the cost of that risk reduction, and allow the Commission to appropriately weigh safety and affordability.")

[51] R.26-04-16 at 13-14. ("In D.25-08-032, the Commission recognized that a PVRR will make BCR calculations more accurate and representative of the lifetime costs of a risk reporting unit and suggests a successor proceeding discuss whether a PVRR metric should be required in BCR calculations.")

[52] Cal Advocates also recommends holding additional workshops on the topics identified in Sections A.1.b. and A.1.c. Many of these items are new topics and would benefit from the interactive exchange that a workshop setting provides.

[53] Rulemaking at 19.

B. Cal Advocates' responses to Appendix A – Substantive Questions.

1. Risk Tolerance

Question 1. Should the definition of Risk Tolerance be updated to reflect affordability concerns?

Yes, the definition of Risk Tolerance should be updated to reflect affordability concerns. Affordability[54] helps determine how much residual risk ratepayers can support.[55] If the cost to achieve an ideal level of residual risk is more than ratepayers can reasonably support, that level of risk reduction may need to be reconsidered or funded through a lower cost mechanism. Affordability shapes what level of residual risk is realistic, and Risk Tolerance should reflect that constraint.

Question 3. Should the Commission adopt a Risk Tolerance Standard or a Framework?[56, 57]

Should the Commission decide to adopt a risk tolerance standard or framework, Cal Advocates recommends that any framework incorporates the tolerance of ratepayers to bill increases. High electric bills in particular can also jeopardize the state's environmental objectives.

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[54] Affordability is defined as "the degree to which a representative household is able to pay for an essential utility service charge, given its socioeconomic status." Rulemaking at 7-8.

[55] D.25-08-032 at 9. ("Risk Tolerance is the maximum amount of overall residual risk remaining in a system managed by the utilities that is deemed **acceptable to ratepayers** after implementation of Controls and Mitigations, weighed against the costs needed for that incremental risk reduction.") (Bold emphasis added)

[56] D.25-08-032 at 17. ("TURN opposes addressing risk tolerance at all, either in Phase 4 of the present proceeding or in a successor proceeding, as it believes that the other proposed changes to the RDF of tracking overall residual risk over time and portfolio optimization can better achieve the goals of a risk tolerance framework.")

[57] D.25-08-032 at 37. ("TURN notes that the output of a budget-constrained optimization process would be a set of portfolios optimized to provide the maximum residual risk reduction for each required budget constraint. That is, the objective function of the optimization process is to minimize residual risk given budget constraints chosen by the Commission with the decision variable being whether or not a given mitigation is included in a portfolio of mitigations for implementation.")

Question 4. How should Risk Tolerance capture the relationship between acceptable level of risk mitigation, tolerance for unmitigated risk, and affordability of rates?

Taking the ratepayers perspective, and tolerance standard should be set in the light of any potential bill impacts. By using optimal mitigation portfolios across the four budget scenarios (85%, 90%, 95%, and 100% of the forecasted costs of mitigations and controls proposed in utility RAMP or GRC filings) adopted in Decision (D.) 25-08-032,[58] Risk Tolerance can capture the relationship between acceptable level of risk mitigation, tolerance for unmitigated risk, and affordability of rates. The optimized risk mitigation portfolio for each budget scenario would help demonstrate which mitigations can be funded at each spending level and the corresponding amount of risk reduction achieved. Each budget scenario represents a different Risk Tolerance. By tying Risk Tolerance to these budget scenarios, cost becomes part of the risk prioritization process from the start and not an afterthought.

Question 5. Should the Commission ask parties to develop Risk Tolerance proposals? If so, what guidance should the Commission provide to parties to develop Risk Tolerance proposals?

See Cal Advocates response to Question 3.

Question 7. How should a benchmark that reflects the level of common risks California utility customers could be reasonably expected to tolerate in their daily lives be calculated?

See Cal Advocates response to Question 4.

2. RAMP

Question 9. Should the Commission also modify the due dates for filing opening and reply comments on RAMP submission and the SPD report?

Yes, the Commission should modify the due dates for filing opening and reply comments on a RAMP submission and the SPD report. The revised GRC application

[58] D.25-08-032 at 125, Conclusions of Law (CoL) #12. ("It is reasonable to require, at minimum, the presentation in the RAMP of the optimal mitigation portfolios for four budget scenarios that are 85%, 90%, 95%, and 100% of the forecasted costs of Mitigations and Controls the filing utility proposed in its RAMP or current GRC.")

filing schedule adopted in D.20-01-002[59] is too compressed and does not provide sufficient time for discovery, workshops, informal comments, and the evaluation of RAMP filings. As the Rulemaking indicates, "SPD staff has found that 110 days is not enough time to complete a thorough and detailed evaluation of a RAMP report and associated workpapers."[60] Since PG&E's 2020 RAMP filing, the Commission has consistently granted extensions for SPD to complete its evaluation of RAMP reports by one to two months.[61] This pattern continued with each consecutive RAMP filing until the recent 2025 RAMP filings from San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company.[62] The consistent need for extensions since 2020 demonstrates that the current due dates are unworkable in practice. Without modification, parties and SPD will continue to request extensions on a case-by-case basis, requiring additional time and effort that could be avoided if the dates were formally updated. Modifying the due dates would formalize what has already become standard practice.

A predictable and realistic schedule is essential to ensure consistency with the Wildfire Mitigation Plan review, which will become aligned with the RAMP review cycle as required by SB254. From 2028 onwards, a utility is required to submit its draft WMP in the same year as its RAMP. Both RAMP and WMP then feed into the same General Rate Case. The Office of Energy Infrastructure Safety's review of the draft WMP will run in parallel with the RAMP. There will be substantial overlap between these filings, consequently consistency and coherence between the two will be essential to avoid the utility and intervenors dealing with potentially conflicting information in the subsequent GRC.

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[59] D.20-01-002, *Modifying the Commission's Rate Case Plan for Energy Utilities*, January 16, 2020, at Appendix A, Table 1.

[60] R.26-04-16 at 12.

[61] Email to Service List: *A.20-06-012 Email Ruling Granting in Part Motion for Extension of Time and Denying Motion for an Order Shortening Time to Respond*, September 23, 2020.

[62] R.26-04-16 at 12-13.

In developing a revised schedule, the Commission should also be mindful that extended deadlines may fall during the Thanksgiving and Christmas holiday periods. Any new schedule should account for the holidays and ensure that deadlines do not fall during those times.

Question 10. How should the formal schedule account for the optional informal comments?

The formal schedule should provide time for informal comments by parties. SPD has indicated that informal comments can aid in its review of utilities' RAMP submissions but requires them to be submitted at least four weeks before its evaluation report is due.[63] Without providing sufficient time for the submission of informal comments into the formal schedule, parties may not have enough time or resources to meet SPD's deadlines. Informal comments filed after that point may not be useful to SPD in developing its evaluation report. Building this time into the formal schedule ensures that the informal comment process remains a meaningful and useful part of the RAMP review.

3. Benefit-Cost Ratio

Question 11. Should the Commission examine how utilities treated O&M expenses in past RAMP filings, the problems these different treatments created, and the lessons learned?

Rather than focus on how utilities treated O&M costs in the past, it is important for the Commission to focus on the conceptual treatment of avoided O&M costs, and avoided costs more generally, within the BCR framework itself. It may be informative to learn how utilities have historically categorized O&M expenses in prior filings. However, rather than focus on past treatment of O&M costs, it is more important to examine whether the handling of avoided O&M costs is grounded in economic theory,

[63] A.25-05-010/013, *Prehearing Conference Reporters' Transcript*, July 23, 2025, at 55-56. ("Discussions with SPD state that they need approximately four weeks for review, revision, in order to approve the final version of the report they issue; That comments coming in at or later than that date can only be appended and not reviewed; That they value intervenor input; And that an optimal amount of time, although SPD like everybody else likes as much time to prepare their work as anybody else, would be three weeks.")

supported by academic cost-benefit analysis literature, and consistent with existing federal and State government guidance. This is explained further in response to question 12, below.

Question 12. Should the Commission examine how other industries, governmental agencies, academia, etc., treat O&M expenses when calculating BCRs?

Yes, the Commission should examine how other industries, government agencies, and academia treat O&M expenses when calculating BCRs. More precisely, the Commission should study how these outside entities treat avoided costs. In their Electrical Undergrounding Plan (EUP) Phase 1 Application, the joint utilities (PG&E, SDG&E, and SCE) propose combining avoided O&M costs with capital expenditures and realized O&M costs in a term they call, "Total Implementation Costs," which would be included in the denominator.[64]

SPD published a white paper that was released with the Scoping Memo for the Phase 1 Application that evaluated alternative BCR formulations based on the placement of avoided O&M costs within the BCR framework.[65] SPD demonstrates that the joint utilities' proposed formulation can produce analytically unstable and economically nonsensical outcomes, including negative and undefined BCR values.[66] SPD further demonstrates that that for all the provided examples, this formulation produced larger BCRs relative to alternative formulations that treat avoided O&M as a benefit in the numerator.[67] In comments responding to the joint utilities' Phase 1 application proposal, Cal Advocates demonstrates that these results are not merely an artifact of the numbers

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[64] A.26-02-005 at 8.

[65] California Public Utilities Commission, Safety Policy Division. *Staff White Paper on Benefit-Cost Ratio Methodology: CPUC Senate Bill 884 Application 26-02-005*. April 10, 2026.

[66] California Public Utilities Commission, Safety Policy Division. *Staff White Paper on Benefit-Cost Ratio Methodology: CPUC Senate Bill 884 Application 26-02-005*. April 10, 2026, at 26.

[67] California Public Utilities Commission, Safety Policy Division. *Staff White Paper on Benefit-Cost Ratio Methodology: CPUC Senate Bill 884 Application 26-02-005*. April 10, 2026. Table 2.

chosen in the SPD white paper.[68] In fact, as long as net benefits are positive, the BCR will be greater when avoided O&M is placed in the denominator rather than the numerator.[69]

In light of these results, it is important that the Commission ensure the adopted BCR formulation is grounded in economic theory, supported by academic cost-benefit analysis literature, and consistent with existing government guidance.

Question 13. Should the Commission adopt a standard method for calculating a PVRR metric or multiplier?

Yes, the Commission should adopt a standard method for calculating a PVRR metric or multiplier. Adopting a standard methodology for calculating PVRR would aid the Commission's evaluation of utility program cost-effectiveness[70] by reducing discrepancies in how utilities calculate BCRs for programs and projects. For example, PG&E already uses a PVRR multiplier in calculating its BCRs,[71] whereas SDG&E does not.[72] Creating a standard framework would eliminate such discrepancies and

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[68] A.26-02-005, *Response of the Public Advocates' Office to A.26-02-005 Scoping Memo Request for Comments and Counter Proposals to Joint IOUs' Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Condition as Specified in Resolution SPD-37*, June 9, 2026 (see explanation that placing avoided O&M costs in the denominator inflates BCRs).

[69] A.26-02-005, *Response of the Public Advocates' Office to A.26-02-005 Scoping Memo Request for Comments and Counter Proposals to Joint IOUs' Proposals for a BCR Calculation Methodology, Audit Methodology, and Cost Recovery Condition as Specified in Resolution SPD-37*, June 9, 2026.

[70] Rulemaking at 13. ("In D.25-08-032, the Commission recognized that a PVRR will make BCR calculations more accurate and representative of the lifetime costs of a risk reporting unit and suggests a successor proceeding discuss whether a PVRR metric should be required in BCR calculations.")

[71] A.24-05-008, *Application of Pacific Gas and Electric Company (U 39M) to Submit its 2024 Risk Assessment and Mitigation Phase Ramp Report,* Excel file "RM-RMCBR-13 PVRR_Charge2020run.xlsx".

[72] *Reply Comments of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 M) on Parties' Comments to Safety Policy Division's Evaluation of the Risk Assessment Mitigation Phase Reports,* December 1, 2025, at 19: : "Although the applicable RAMP framework does not require revenue-requirement modeling or cost-of-service ratemaking inputs, it does require evaluation of direct mitigation costs necessary to accomplish the work. The Companies have provided those costs and will incorporate them in their TY 2028 GRC applications in accordance with the RDF requirements, which includes those adopted in the Commission's Phase 4 Decision."

additionally ensure that a robust, transparent, repeatable, and auditable model is adopted for utility use with appropriate Commission and stakeholder input.

To ensure that the Commission and parties have sufficient information to determine what this standard method should be, the Commission should direct SPD to hold a workshop regarding PVRR metrics that includes a PG&E presentation of its CHARGE tool as a guide. To help guide the discussion and topics of this workshop, Staff should additionally issue a whitepaper regarding currently existing PVRRR metrics, similar to what was issued regarding BCR methods in A.26-02-005.[73] This will provide stakeholders a holistic view of what methods currently exist for calculating PVRR and their respective advantages and disadvantages such that the workshop discussion is as productive as possible.

Question 13.1. If so, what requirements should this standard method include and what costs (e.g., rate of return, taxes, etc.) should the PVRR metric or multiplier account for?

Whichever method the Commission chooses should include (but not be limited to) the following costs that ratepayers incur for capital projects and programs over the life of the asset:

i. Capital costs.
ii. Inspection costs.
iii. Maintenance costs.
iv. Repair costs.
v. Operation costs.
vi. Expense costs.
vii. Engineering costs.
viii. Permitting costs.
ix. Depreciation costs (including negative salvage value costs).
x. Rate of return and debt costs to ratepayers.

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[73] A.26-02-005, 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, *Staff White Paper on Benefit Cost Ratio Methodology,* April 10, 2026.

xi. Asset retirement costs.

xii. Asset removal and asset disposal costs at end of useful life.

xiii. Taxes.

xiv. Other costs recovered from ratepayers.

Question 14. Should the Commission examine how PG&E calculated its PVRR multiplier to estimate costs in its 2024 RAMP?

Yes, the Commission should examine how PG&E calculated its PVRR multiplier to estimate costs in its 2024 RAMP in a workshop setting. This will provide a starting place for the Commission and parties to obtain necessary information to develop a standard PVRR metric or multiplier.

Question 15. Should the Commission adopt a similar approach as PG&E's, with modifications as the Commission deems necessary, for calculating a PVRR metric or multiplier to be applied to the cost of capital projects and programs presented in RAMPs?

As noted in our response to Question 13, the Commission should adopt a standard PVRR metric or multiplier as it will provide the Commission and parties with a more complete picture of the costs of capital projects and programs when comparing alternative mitigations. Cal Advocates does not comment here on whether the approach should be similar to PG&E's. We do recommend a workshop that discusses this question and any possible alternative methods for calculating PVRR.

Question 16. Should the PVRR metric or multiplier be calculated and applied at the Risk Reporting Unit (RRU), program, risk, line of business, enterprise, or other level?

The Commission should require that the PVRR metric or multiplier be calculated and applied at the most granular level that is available at the time it is generated. This would best fulfill the goal of making BCRs "more accurate and representative of the lifetime costs of a risk reporting unit"[74] and thus capturing the true costs of capital investments to ratepayers when comparing alternative mitigations. Cal Advocates recommends that a forthcoming PVRR workshop discuss what the best available data is

[74] Rulemaking at 14, citing to D.25-08-023 at 121.

currently and how more granular data can be generated as needed to get the most accurate PVRR metric or multiplier.

Question 17. Which interest rate or rates should be used to calculate the PVRR metric or multiplier?

Cal Advocates does not have input on this question at this time. Cal Advocates recommends that the Commission hold a workshop on PVRR that discusses this and other topics.

Question 18. Should the Commission modify the RDF, RAMP Data Template Guidelines, and other guidelines/requirements as necessary to explicitly specify that costs of capital projects and programs used in BCR calculations must be based on the estimated PVRR?

Yes, the Commission should modify all applicable guidelines/requirements including those listed above, to specify that costs of capital projects and programs used in BCR calculations must be based on the estimated PVRR. This will ensure that the Commission and parties have a more accurate view of the potential costs of capital projects and programs to California ratepayers when determining the cost-effectiveness of utility proposals.

Question 19. Should the Commission address other outstanding issues relating to BCR methodology and/or calculation? If so, which ones and why?

The Commission should also address the issue of risk scaling and risk aversion as it pertains to BCR calculation, as discussed in Section A, above. Developing a standard framework for incorporating risk aversion will ensure that BCRs accurately incorporate the risk preferences of utility ratepayers.

4. SMJU Reporting

Question 20. What barriers to extending RSAR requirements to Alpine and WCG should the Commission consider?

Cal Advocates supports extending the Risk Spending Accountability Report (RSAR) requirements to Alpine and WCG in compliance with Public Utilities Code

Section 591.[75] Financial and progress tracking is essential for curtailing safety risks. The Commission should keep in mind potential impacts to the current RSAR schedule for SMJU.[76] If the review schedule is not adjusted, there may be limited resources to properly review and comment on Alpine or WCG RSARs.[77] The Commission must also be mindful of the additional work this creates for Alpine and WCG. The implementation of RSARs should allow for a reasonable transition period[78] to allow Alpine and WCG to develop their work processes and documents. Thereafter RSAR should be extended to align with the other SMJUs.[79]

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[75] PUC Section 591:

> "(a) The commission shall require an electrical or gas corporation to annually notify the commission, as part of an ongoing proceeding or in a report otherwise required to be submitted to the commission, of each time since that notification was last provided that capital or expense revenue authorized by the commission for maintenance, safety, or reliability was redirected by the electrical or gas corporation to other purposes.
>
> (b) The commission shall ensure that the notification provided by each electrical or gas corporation is also made available in a timely fashion to the Office of the Safety Advocate, Public Advocate's Office of the Public Utilities Commission, and parties on the service list of any relevant proceeding."

[76] The referenced SMJUs includes Bear Valley Electric Service, Inc., Pacificorp, d.b.a. Pacific Power, liberty Utilities (Cal Peco Electric) LLC, and Southwest Gas.

[77] Pursuant to Ordering Paragraph (OP) 5 of D.22-10-002:

> "b. Energy Division Staff will provide a review of SMJU RSARs by November 1st annually; and
>
> c. The SMJUs shall file their RSARs annually by May 1 in their most general rate case (GRC) proceeding, the GRC proceeding where the RSAR costs are imputed, and with the Energy Division to: energydivisioncentralfiles@cpuc.ca.gov."

[78] D.19-04-020, *Phase Two Decision Adopting Risk Spending Accountability Report Requirements and Safety Performance Metrics for Investor-Owned Utilities and Adopting a Safety Model Approach for Small and Multi-Jurisdictional Utilities*, April 25, 2019, at 50. ("We concur with Southwest Gas that it may be difficult for the SMJUs to strictly follow Staff's suggested approach for the first few years of transitioning to RSAR reporting. Therefore, we approve a general, simplified approach for the SMJUs to follow in their annual RSAR reports for the time-being.")

[79] Pursuant to OP 4 of D.22-10-002.

III. CONCLUSION

Cal Advocates recommends that the Commission adopt the proposed recommendations above to restructure this rulemaking into multiple phases and expand the proposed scope of topics.

Respectfully submitted,

/s/ MICHAEL EINHORN

Michael Einhorn
Attorney for the

The Public Advocates Office
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102
Telephone: (415) 703-4852
Email: Michael.Einhorn@cpuc.ca.gov

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